Docket No. UE 390
Exhibit SC/100
Witness: Ed Burgess

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER, 2022 Transition Adjustment Mechanism	Docket UE 390

Opening Testimony of Ed Burgess

On Behalf of
Sierra Club

Redacted Version

June 9, 2021

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1. Summary of Findings and Recommendations

Q. Please provide a summary of your testimony.

A. My testimony examines the fuel expenditures PacifiCorp proposes to recover through its 2022 Transition Adjustment Mechanism ("TAM"). I identify several problems in the Company's coal fuel expenditures that are leading to higher ratepayer costs than necessary. I also provide several recommendations that help to correct for these issues.

Q. Please provide a summary of your findings.

A. My findings can be summarized as follows:

1. PacifiCorp's Generation and Regulation Initiative Decision ("GRID") model used to forecast Net Power Costs ("NPC") is not a true optimization based on either short-run or long-run marginal costs. Instead, PacifiCorp manipulates the inputs to its GRID model to ensure that enough coal is burned to meet contractual minimum take requirements.
2. Even for fuel supplies that do not include minimum take penalties, such as with coal supplying the Jim Bridger plant, the GRID model inputs are highly distorted and do not reflect the true incremental cost and flexibility associated with fuel from those sources.
3. PacifiCorp's projected 2022 NPC includes a significant amount of costs associated with future coal supply agreements that have not been executed and are speculative in nature.
4. PacifiCorp's use of a supplemental pricing tier at Jim Bridger is inappropriate and skews coal consumption higher than necessary, both in it is NPC forecasts and in actual unit commitment and dispatch decisions.

5. PacifiCorp's new coal supply agreements ("CSAs") for the Hunter plant include high minimum take provisions that equate to up to [redacted] percent of projected generation at the plant.

Q. Please provide a summary of your recommendations.

A. My recommendations are:

1. The Commission should direct PacifiCorp to revise the NPC component of the proposed 2022 TAM to account for inappropriate coal fuel costs forecasted for the Jim Bridger plant which arise from incorrect assumptions about the marginal cost in GRID and lack of consideration for the flexibility of this fuel source.
2. Going forward, the Commission should ensure that PacifiCorp's NPC projections reflect the true incremental costs of fuel, especially when there is no pre-existing shortfall penalty or approved contract, and that other distortions (e.g. erroneous penalty payments, avoidable fixed costs, etc.) are not included in the projection model.
3. The Commission should only approve 2022 TAM rates on an interim basis for any projected costs associated with PacifiCorp's open position fuel supplies at Jim Bridger (Black Butte), Naughton (Kemmerer), and Dave Johnston (Unspecified Powder River Basin "PRB" source). These rates should be updated once the Commission has had a chance to review the specific contract details, which PacifiCorp should provide as a supplemental filing including additional GRID model runs. Reasonable assumptions about these contracts should be used now for GRID modeling purposes, to estimate the remainder of 2022 TAM costs.

4. Similarly, the Commission should defer final approval of any fixed costs for Bridger Coal Company ("BCC") coal included in the 2022 TAM until the Commission has had an opportunity to review what actual costs were incurred, and whether these were prudent.
5. The Commission should require PacifiCorp to provide a tracking report detailing PacifiCorp's daily unit commitment and dispatch decisions for each of its thermal plants over the course of 2022. This report should include details on: 1) marginal fuel costs assumed by PacifiCorp's energy traders, 2) expected operating costs, 3) expected market price, 4) whether the plant was operated as "must run" or economically committed, and 5) what the assumed cycling costs were.
6. As a requirement of future TAM filings, the Commission should require PacifiCorp to include a report on the steps it has taken to reduce ratepayer costs associated with the BCC mine and replace this generation with lower cost sources.
7. The Commission should deem the new Hunter CSA minimum take quantities to be imprudent. As a remedy, any future minimum take penalties that arise from the Hunter CSAs should not be recovered from PacifiCorp customers.
8. The Commission should establish best practices for future coal supply agreements, including limiting the minimum take quantity, shortening contract terms to the extent practicable, including provisions that allow for avoidance of minimum take requirements, and forecasting anticipated generation using average costs in anticipation of coal contract negotiations.
9. The Commission should require PacifiCorp to provide copies of its coal supply agreements and affiliate mine plans as a standard part of future TAM applications.

The process of providing these documents should abide by any and all necessary protective order agreements to ensure any competitively confidential information is protected.

10. I recommend that the Commission conduct a comparison of each cost recovery mechanism to ensure that there are no duplicative depreciation costs for the BCC mine being recovered in both base rates and the TAM.

2. <u>Introduction</u>

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

A. My name is Ed Burgess. I am a Senior Director at Strategen Consulting. My business address is 2150 Allston Way, Suite 400, Berkeley, California 94704.

Q. Please summarize your professional and educational background.

A. I am a leader on Strategen's consulting team and oversee much of the firm's utility-focused practice for governmental clients, non-governmental organizations, and trade associations. Strategen's team is globally recognized for its expertise in the electric power sector on issues relating to resource planning, transmission planning, renewable energy, energy storage, utility rate design and program design, and utility business models and strategy. During my time at Strategen, I have managed or supported projects for numerous client engagements related to these issues. Before joining Strategen in 2015, I worked as an independent consultant in Arizona and regularly appeared before the Arizona Corporation Commission. I also worked for Arizona State University where I helped launch their Utility of the Future initiative as well as the Energy Policy Innovation Council. I have a Professional Science Master's degree in Solar Energy Engineering and Commercialization from Arizona State University as well as a Master of Science in

Sustainability, also from Arizona State. I also have a Bachelor of Arts degree in Chemistry from Princeton University. A full resume is attached as Exhibit Sierra Club/101.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Sierra Club.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to 1) provide an examination of PacifiCorp's Transition Adjustment Mechanism as it relates to coal fuel burn expenditures, 2) describe how PacifiCorp forecasts coal generation costs and identify problems with this approach, 3) examine PacifiCorp's contracting practices regarding its new coal supply agreements, 4) analyze PacifiCorp's treatment of coal fuel costs from the Bridger Coal Company. I also provide recommendations on ways to make improvements to the 2022 TAM and future TAMs.

Q. Have you ever testified before this Commission?

A. Yes. I testified in UE 375, which was PacifiCorp's 2021 TAM proceeding.

Q. Are you generally familiar with electric utilities, and related policy and regulatory issues around the Western U.S.?

A. Yes. I have participated in a variety of activities, projects, and policy forums related to the power system in the West. To provide a few recent examples, I have conducted multiple research projects for the Western Interstate Energy Board. I have participated in technical stakeholder processes at the Western Electricity Coordinating Council and WestConnect. I helped the State of Arizona complete a technical assessment (including power system modeling) of U.S. EPA's Clean Power Plan. I have also engaged in several resource planning and grid modeling activities in Arizona, Nevada, and Colorado. For a recent client project, I conducted a detailed review and comparison of PacifiCorp's retail rate components across its six jurisdictions. I also recently testified before the California Public Utility Commission on PacifiCorp's proposed 2021 Energy Cost Adjustment Clause, which is the California equivalent of the TAM.

Q. Have you ever testified before any other state regulatory body?

A. Yes. I have testified before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General's Office ("AGO") at the evidentiary hearings for D.P.U. 18-150 and D.P.U. 17-140. I have also supported the AGO as a technical consultant in other cases including D.P.U. 17-05, D.P.U. 17-13, D.P.U. 15-155, and D.P.U. 17-146. I have also testified before the South Carolina Public Service Commission on behalf of the South Carolina Solar Business Alliance in evidentiary hearings for 2019-186-E, 2019-185-E, and 2019-184-E. I provided written testimony to the Indiana Utility Regulatory Commission on behalf of the Citizens Action Coalition and Earthjustice on coal fuel costs in two proceedings related to Duke Energy's Fuel Adjustment Clause (IURC Cause No. 38707 FAC 123 S1 and FAC 125). I also recently provided testimony to the Nevada PUC on NV Energy's Integrated Resource Plan (Docket No 20-07023). I have testified before the California Public Utilities Commission on behalf of Sierra Club in PacifiCorp's 2020 and 2021 Energy Cost Adjustment Clause proceedings (A.19-08-002 and A.20-08-002). Additionally, I have represented numerous clients by drafting written testimony, drafting written comments, presenting oral comments and participating in technical workshops on a wide range of proceedings at Public Utilities Commissions in Arizona, California, District of Columbia, Maryland, Minnesota, Nevada, New Hampshire, New York, North Carolina, Ohio, Oregon, Pennsylvania, at the Federal Energy Regulatory Commission, and at the California Independent System Operator.

Q. How is your testimony organized?

A. My testimony is organized into the following five sections:

1. Overview of the key features of PacifiCorp's Transition Adjustment Mechanism;
2. Assessment of how Net Power Costs are forecasted by PacifiCorp using the GRID model;
3. Assessment of PacifiCorp's coal contracting practices, including their application to several new contracts;
4. Analysis of coal fuel expenses at the Jim Bridger plant;
5. Summary of recommendations for how to improve the Transition Adjustment Mechanism in this proceeding and going forward.

3. The Transition Adjustment Mechanism and PacifiCorp's 2022 TAM Application

A. Overview of the TAM

Q. What is the purpose of the Transition Adjustment Mechanism?

A. The Transition Adjustment Mechanism ("TAM") is a rate adjustment that PacifiCorp files annually to update its forecasted Net Power Cost ("NPC") calculation. The NPC is in turn used to determine the power supply rates for customers who have elected to take cost-based supply service (e.g. under Rate Schedule 201). These rates recover costs primarily related to the fuel and purchased power costs associated with power generated or procured to serve PacifiCorp's customers.

Q. What is the significance of the TAM for a typical residential customer's bill?

A. In PacifiCorp's case, fuel costs are on the order of $0.02-0.025/kWh, or roughly 20-25% of standard residential energy rates.[1] Given the impact on captive customers' bills, proceedings like this one are very important for customers.

Q. Does the TAM include a mechanism to true up any discrepancies between the actual NPC and forecasted NPC fuel and power purchase costs?

A. No. The TAM only includes the forward-looking fuel cost component. A separate adjustor, the Power Cost Adjustment Mechanism ("PCAM"), is used to "true up" the actual dollar-for-dollar fuel expenditures that have occurred in both the current and prior year.

Q. Is it possible that the actual fuel costs would differ substantially from the TAM forecast, thereby requiring a substantial adjustment in the PCAM?

A. In previous TAM cases, I would expect that there might not be much discrepancy between the TAM forecast, and the actual costs. Any discrepancy that would occur would likely fall within the PCAM's deadbands, thus requiring no adjustment. For instance, in the 2020 PCAM that PacifiCorp recently filed in May 2021, the Company reported an under-collection of $29.5 million, which does not exceed the $30 million threshold of the deadband, therefore requiring no adjustment (i.e., PacifiCorp absorbs these costs). However, starting with the 2022 PCAM I think there could be a greater possibility that PacifiCorp may claim an under-collection amount that exceeds this threshold.

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[1] Assuming $0.10/kWh for baseline PacifiCorp's residential energy charges.

Q. Can you explain why?

A. Yes. The 2022 TAM is the first time that PacifiCorp has estimated NPC with all "must run" constraints removed from its GRID model. This contributed to a $114 million reduction in coal fuel costs versus the 2021 forecast.[2] Meanwhile, the Company has argued that the removal of this constraint may not reflect real-world operations. Thus, it is very possible that the Company would not change its actual unit commitment and dispatch practices to allow for the economic cycling reflected in the 2022 TAM forecast. If that happens, then the actual coal fuel consumed could be substantially higher than the 2022 forecast, and could lead to the need for a true up in the 2022 PCAM.

Q. Do you have any recommendations based on this?

A. Yes. I think it is critical for the Commission to carefully scrutinize PacifiCorp's unit commitment and dispatch practices going forward to ensure that they are adequately minimizing costs, including through economic cycling of coal units (if warranted). As part of this, I believe PacifiCorp should demonstrate that it is regularly conducting analyses to determine the potential benefits of economic cycling (net of any startup costs) during its actual unit commitment decisions. These decisions should then be closely examined in the PCAM to determine if any requested true up for under-recovery is truly warranted or could have been avoided if more economic commitment and dispatch practices were followed.

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[2] PAC/100 at Webb/20:18-19.

B. PacifiCorp's 2022 TAM Application and Net Power Cost Calculation

Q. Please provide a brief overview of PacifiCorp's application for approval of its 2022 TAM.

A. On April 1, 2021, PacifiCorp submitted an application to this Commission requesting authorization to update certain components of its TAM for 2022. These components include 2022 NPC, NPC adjustments, Production Tax Credits ("PTC"), as well as transmission credits for direct access customers.

Q. Have you reviewed PacifiCorp's testimony and supporting workpapers in this proceeding regarding the calculation of the 2022 TAM?

A. Yes. I reviewed the core components of the TAM as described above. As explained, the primary component of the 2022 TAM is PacifiCorp's forecasted NPC for the year 2022, a portion of which (~25.8%) is allocated to Oregon.

Q. Can you further describe the core components of the TAM—namely the amount of NPC to be included in customer rates?

A. Yes. In the TAM, the NPC is the calculation of projected power costs to be collected in rates and is based on a forecast of PacifiCorp's fuel expenses, wholesale purchase power expenses, and wheeling expenses less wholesale sales revenue for the coming year. It is forward looking and intended to proactively recover PacifiCorp's expected future fuel costs as they occur.

Q. What is the total-company NPC in the TAM for calendar year 2022 (prior to adjustments and tax credits)?

A. The forecasted total-company NPC for calendar year 2022 is $1.445 billion.[3] Corrections on the GHG benefit forecast, the market capacity limits, and the allocation of the Reasonable Energy Price Adjustment were filed on May 25, 2021 and will be fully quantified in the Company's rebuttal testimony. Approximately 26% of the forecasted NPC, or $372 million, is allocated to Oregon.[4]

Q. What adjustments are made to NPC for the purpose of the setting the 2022 TAM power supply rates?

A. The largest adjustment is the subtraction of the PTC, which totals $66.2 million for 2022. Additional Oregon Situs NPC adjustments result in a $1.6 million reduction. Thus, the Oregon-allocated revenue requirement targeted for rate recovery through the TAM is approximately $304 million.[5]

Q. Can you summarize the underlying components of the NPC in TAM 2022?

A. Yes. The main components of the total NPC are summarized in the following table, based on Exhibit PAC/101. Note that these do not include certain corrections PacifiCorp identified in a filing on May 25, 2021, but has not quantified at the time of this filing.

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[3] PAC/101 at Webb/1.
[4] *Id.* at Webb/1.
[5] *Id.* at Webb/1.

Table 1: 2022 NPC Components

Category	Total Company (million)	Oregon allocated (million)
Special sales for resale	$ 253	$ 67
Purchased power	$ 664	$ 175
Wheeling expense	$ 148	$ 39
Fuel expense	$ 887	$ 225
Coal Fuel Burn expenses	*$ 543*	*$ 138*
Gas/Other Fuel Burn expenses	*$ 343*	*$ 85*
Net power cost (per grid)	$ 1,445	$ 372
Oregon situs NPC adjustments	$ (1.6)	$ (1.6)
Total NPC	$ 1,444	$ 371

As the table above shows $543 million of fuel costs are for coal fuel expenses. Thus, nearly 38 percent of the NPC is comprised of costs for burning coal.

Q. How does PacifiCorp estimate its future Net Power Costs for purposes of calculating the 2022 TAM?

A. According to Mr. Webb's testimony, PacifiCorp uses its Generation and Regulation Initiative Decision Tool ("GRID"), which is a production cost model, to simulate the operation of the company's power system on an hourly basis. This provides an estimate of the projected amount of generation that will occur at each of PacifiCorp's generation units, as well as purchased power, to serve its own load and for off-system sales.

Q. Please describe the role of GRID in estimating NPC.

A. GRID is a production cost model. Production cost models find the least cost dispatch of a set of generators that meet the forecasted demand. As such, PacifiCorp could use GRID to forecast the operations of the Company's system that would result in the lowest cost for ratepayers. However, there are certain modeling inputs and choices that the Company makes that result in deviations from the least cost dispatch. Some of these choices can also occur in actual operations, resulting in increased costs for ratepayers.

C. *Cost of Coal Fuel Included in the 2022 TAM*

Q. Can you provide a breakdown of the coal fuel burn expenses that are included in the 2022 NPC Projections?

A. Yes. As reflected in workpaper ORTAM22 NPC CONF, the anticipated 2022 coal fuel burn expenses can be broken down by plant as follows:

Confidential Table 2: Unit Average Cost based on 2022 projected NPC and generation

Plant	2022 Projected Coal Burn Expenses ($)[6]	2022 Projected Generation (MWh)[7]	Average Cost ($/MWh)[8]
Cholla	$ -	-	$ -
Colstrip	14,529,149	[redacted]	[redacted]
Craig	19,084,507	[redacted]	[redacted]
Dave Johnston	61,444,601	[redacted]	[redacted]
Hayden	11,378,872	[redacted]	[redacted]
Hunter	103,544,708	[redacted]	[redacted]
Huntington	99,945,126	[redacted]	[redacted]
Jim Bridger	185,570,462	[redacted]	[redacted]
Naughton	24,416,678	[redacted]	[redacted]
Wyodak	23,501,147	[redacted]	[redacted]
Total	$ 543,415,251	[redacted]	[redacted]

Q. How does the coal fuel burn expense projected in the 2022 TAM differ from the 2021 TAM projection?

A. PacifiCorp's projected coal fuel expense is $114 million lower, or over 17 percent less, than the 2021 TAM forecast because of the lower coal generation volume at PacifiCorp's coal plants.[9]

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[6] PAC/102 at Webb/5.

[7] Confidential workpaper accompanying the Direct Testimony of David Webb (PAC/100) "ORTAM22 NPC CONF.xlsm" at "NPC" tab [hereinafter ORTAM22 NPC CONF (Webb)].

[8] *Id.*

[9] PAC/100 at Webb/20:18-19.

Q. What are the drivers of this substantial decrease?

A. According to PacifiCorp, this is largely due to the Company's continual efforts to update its fueling strategy. As Mr. Ralston states: "[t]his is due to PacifiCorp's continued efforts to work with its coal suppliers and mines for the benefit of our customers."[10]

Q. Do you agree with this?

A. Not entirely. For example, I would agree that the Company is projecting a substantial reduction in coal burn associated with the Naughton plant, which has historically had one of the most expensive fuel sources in PacifiCorp's fleet. However, no coal supply agreement for Naughton is currently in effect for 2022, so it remains to be seen if PacifiCorp's efforts will be successful in reducing these costs by a commensurate level. Additionally, while there was also meaningful reduction in the relatively expensive cost of coal fuel at the Jim Bridger plant, it is not apparent that all steps were taken to reduce these costs. I will explore this more fully in Section 6 of my testimony. Finally, I believe that another major reason for the reduction is not necessarily PacifiCorp's fueling strategy, but rather the fact that PacifiCorp removed the "must run" constraint from the GRID model. When operating as "must run," GRID assumes that PacifiCorp's coal plants operate year around at a specific minimum operating capacity. The removal of this constraint was required as part of the TAM 2021 settlement and is discussed further below. In other words, ratepayers will benefit because the Company was asked to forecast a more economic method for dispatching its coal fleet, rather than assuming that coal units should operate irrespective of their cost—a practice that PacifiCorp was following in previous years.

[10] PAC/200 at Ralston/23:13-14.

Q. What do you conclude from comparing coal unit average costs?

A. Across PacifiCorp's coal fleet, there is a significant range in coal fuel related costs projected for 2022. On average, the NPC for all of PacifiCorp's coal plants is expected to be $[redacted]/MWh, however for some plants the cost is much higher. For example, the Jim Bridger and Naughton plants have projected coal fuel burn expenses of $[redacted]/MWh and $[redacted]/MWh, respectively.

Q. Do these costs, recovered through the TAM, include all of the anticipated costs to PacifiCorp customers for obtaining coal fuel?

A. No. For PacifiCorp's affiliate mines, some of the ongoing costs are recovered as capital expenditures in rate base. For example, PacifiCorp's share of Bridger Coal Company ("BCC") is included in the Company's rate base while other costs including mining costs, depreciation and depletion, and other operating costs are including in NPC and recovered through the TAM. According to the Company, this is a "cost-based approach, limiting the price of Bridger Coal Company coal in rates to operating expenses, plus PacifiCorp's authorized rate of return on the investment in the mine."[11] In reality, coal from BCC has the [redacted] in TAM out of all of the Company's coal fuel sources and as mentioned earlier this does not even include additional costs (e.g. operations & maintenance, fixed costs in rate base) that make the economics of continuing to operate BCC even worse. Regardless of its economic competitiveness, the Company has an incentive to keep operating the mine and plant because it continues to earn a rate of return on the underlying assets and any future capital improvements to them.

[11] The Redacted Comparison Report related to "PacifiCorp's Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant" at 4 (provided as an attachment to the PacifiCorp Response to Sierra Club Data Request 1.31) (attached as Exhibit Sierra Club/102).

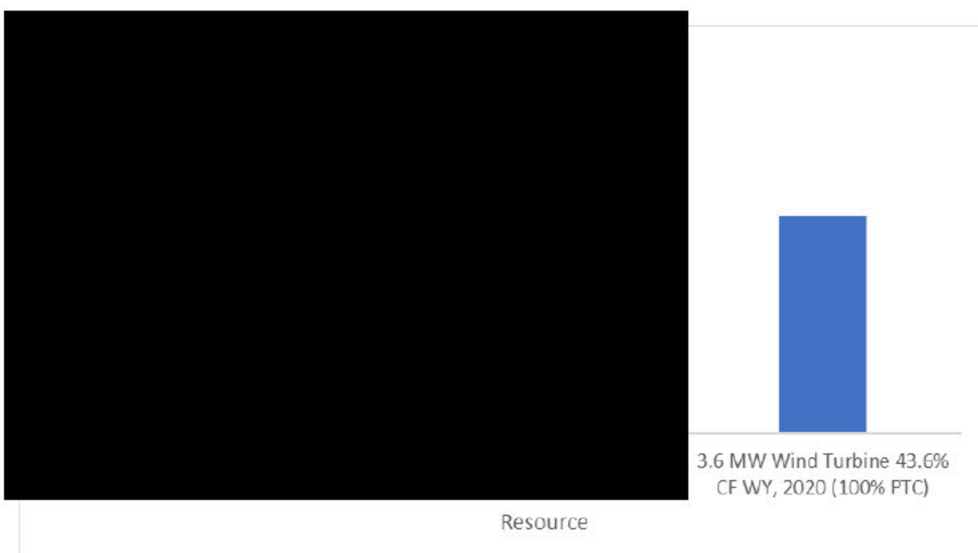
D. <u>2021 Coal Fuel Compared to Alternatives</u>

Q. How do the projected coal burn expenses at Jim Bridger compare to potential alternatives?

A. On a simple $/MWh basis, the average coal burn expenses of the Jim Bridger plant, among others, is significantly higher than costs of potential alternatives including: other PacifiCorp-owned coal plants, PacifiCorp-owned natural gas plants, and new (2020 installation) renewable energy resources that could have been installed prior to the 2022 TAM. The table and chart below provide a cost comparison of these different resources.

Confidential Table 3: 2021 Average Cost of Coal Units and Alternatives[12]

Resource	Average Cost ($/MWh)	Source
Jim Bridger Coal Plant	[redacted]	2022 NPC Projection, Workpaper ORTAM22 NPC CONF
PacifiCorp Gas Fleet Average	[redacted]	2022 NPC Projection, Workpaper ORTAM22 NPC CONF
3.6 MW Wind Turbine 43.6% CF WY, 2020 (100% PTC)	17.08	2019 PacifiCorp IRP Projection



[12] ORTAM22 NPC CONF (Webb) at “NPC” tab.

Q. Can PacifiCorp replace a substantial portion of its coal fleet's generation with these other sources in 2022?

Yes. In fact, this is already occurring. For example, the wind resources associated with the Energy Vision 2020 project are already displacing some of the Company's high-cost fossil fuel generation. The Energy Vision 2020 project adds three new wind projects in Wyoming providing a total 1,150 MW of new wind energy capacity: TB Flats, Cedar Springs II, Ekola Flats, and a power purchase agreement ("PPA"), Cedar Springs I.[13] In addition to the Energy Vision 2020 Projects, the TAM also includes two following wind projects: the 240 MW Pryor Mountain wind project and the 133.3 MW Cedar Springs III PPA.[14]

Q. Is the addition of the Energy Vision wind resources expected to result in NPC savings projected for the 2022 TAM?

A. Yes, according to Mr. Webb's testimony, the new wind resources, which are forecasted to deliver 5,335 GWh of wind in 2022, will result in a $111 million reduction in NPC.[15] The majority of these savings ($76.2 million) comes from reducing high-cost coal generation.[16] Out of the $76.2 million of savings, $[redacted] come from reducing generation from Jim Bridger, $[redacted] from reducing generation from Hunter, [redacted] from reducing generation from Huntington, and the remaining $[redacted] from the other coal units.[17] In addition to the NPC savings, there will be significant PTC

[13] PAC/100 at Webb/25:5-26:2.
[14] *Id.* at Webb/26:5-7.
[15] *Id.* at Webb/27:9-10; 28 (Figure 5).
[16] *Id.* at Webb/28 (Figure 5).
[17] Author's calculation based on the "NPC" tabs in the confidential workpapers accompanying the Direct Testimony of David Webb (PAC/100) "zz_OneOffORTAM22_xNewWind CONF.xlsm" and "ORTAM22 NPC CONF.xlsm".

benefits (over $[redacted]).[18] For owned projects, these savings would be reduced by the (annualized) capital expenses required to build those projects. However, Cedar Springs Wind I, which is contracted through a PPA, provides the clearest cost comparison between the cost of new wind resources and PacifiCorp's existing coal fleet. Specifically, based on the forecasted generation and cost in the Company's NPC analysis, these PPAs appear to have a price around $[redacted]/MWh, which is even more competitive than what was estimated in the 2019 IRP.[19]

Q. Do you think PacifiCorp could have been doing even more to replace some of its high-cost coal generation prior to 2022?

A. Yes. While clearly PacifiCorp has taken some steps in the right direction, it also has known for many years that generation costs at plants like Jim Bridger are very high, and I believe the Company could have taken additional steps to secure lower cost resources in advance of 2022. For example, in the 2022 TAM, PacifiCorp's generation estimates (MWh) at Jim Bridger represent only a [redacted] percent reduction from 2020 actual generation levels[20] and a [redacted] percent reduction versus 2019 generation levels.[21] For comparison purposes, I analyzed the 8760 hourly output profile of a hypothetical Wyoming wind resource and compared it to Jim Bridger's hourly net generation in 2019. I found that a wind resource sized similarly to PacifiCorp's ownership share of the plant could displace at least 50% of the Company's share of Jim Bridger's output on a time-coincident basis. While I recognize there are always practical concerns with this type of simplistic

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[18] Author's calculation based on PAC/100 at Webb/27 (Confidential Figure 4).
[19] Author's calculation based on ORTAM22 NPC CONF (Webb) at "NPC" tab.
[20] Author's calculation based on the confidential workpaper accompanying the Direct Testimony of David Webb (PAC/100) "Actual NPC_2020 CONF.xlsx".
[21] Author's calculation based on estimated 2019 net generation of 11,255 GWh (plant total) as reported in S&P Global Market Intelligence database.

analysis, I think it is still useful as an illustrative example to consider the magnitude of benefits that ratepayers could have been receiving if PacifiCorp had transitioned away from its higher cost resources, such as the Jim Bridger plant, at a faster pace.

4. <u>PacifiCorp's Forecast Methodology for Coal Generation</u>

A. <u>Overview of the GRID Model</u>

Q. How does PacifiCorp estimate its future NPC for purposes of calculating the 2022 TAM?

A. PacifiCorp uses GRID to simulate the operation of the company's power system on an hourly basis. This provides an estimate of the projected amount of generation that will occur at each of PacifiCorp's generation units, as well as purchased power, to serve its own load and for off-system sales.

Q. Have you reviewed the inputs and assumptions used by the GRID model?

A. Yes.

Q. Do you have any concerns about how the GRID model may be operating to calculate NPC based on these inputs?

A. Yes. I'm concerned that some of the inputs included in the GRID model may be leading to excessive projections of coal dispatch at some plants, beyond what may be prudent for PacifiCorp's customers. This excess dispatch may also be occurring during actual operations for similar reasons. Moreover, excess dispatch could also be assumed during coal contract negotiations, which also rely on GRID model runs as a starting point.[22] The GRID model may reflect how PacifiCorp actually operates its system and negotiates new

[22] PacifiCorp Response to Sierra Club Data Request 1.22. All public data responses referenced in this testimony are compiled and attached as Exhibit Sierra Club/103.

coal supply agreements. However, this does not mean that the level of coal generation forecasted by GRID is either appropriate or reasonable. Nor does it mean the amount of coal PacifiCorp contracts for or consumes in actual operations is reasonable either.

B. GRID Model Inputs and their Impact on Coal Generation

Q. How might the GRID model inputs lead to excessive generation at a particular generation unit?

A. Since the GRID model is a production cost simulation, it performs a cost-minimization procedure to determine the least-cost set of resources for meeting PacifiCorp's load in each hour of the year (or some approximation thereof). The resulting generator commitment and dispatch decisions are in turn guided by unit-specific inputs for the cost of production such as fuel commodity prices, heat rates, and variable operation and maintenance ("O&M") costs. Excessive dispatch could occur if the production cost inputs are set too low and do not capture the full range of costs that are ultimately paid by PacifiCorp's customers through the TAM.

i. Removal of Must Run Constraint for 2022 Forecast

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

A. The "must run" setting for coal units in GRID keeps the coal units operating throughout the year regardless of whether they are economic compared to the rest of the available resources. According to company witness, David G. Webb, the "must run" constraint was used in GRID in the past because "the purpose of the TAM is to model actual operations" and during actual operations coal units are typically not cycled off for economic reasons.[23] In some instances, they may be operated at their minimum levels, but are not cycled off entirely.[24] However, the fact that the Company has historically operated coal units as must run does not mean that cycling is infeasible or could not produce additional economic benefits. PacifiCorp's past practice also does not mean that the "must run" setting should be applied in the GRID forecast. On the contrary, an appropriately conducted forecast, without unnecessary "must run" constraints, could be used to help evaluate the reasonableness of PacifiCorp's past practices and identify opportunities to further reduce costs through economic cycling.

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

A. The Company agreed to the removal of the constraints as part of the 2021 TAM settlement agreement.[25]

Q. Does PacifiCorp raise any concerns about the removal of the "must run" constraints?

A. Yes. According to Mr. Webb, economic cycling can result in shutdown of the units and subsequent start-up costs that are not properly reflected within GRID, as well as reliability risks associated with the start time necessary to bring a coal unit back online. PacifiCorp points to these additional costs and reliability risks as the reason that it will cycle a coal unit to its minimum when needed but not entirely shut the plant down during

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[23] PAC/100 at Webb/13:22.
[24] *See e.g.*, *id.* at Webb/13:20-21.
[25] *In the Matter of PacifiCorp, dba Pacific Power, 2021 Transition Adjustment Mechanism*, Docket No. UE 375, Order No. 20-392, Appendix A at 6 of 25 (Oct. 30, 2020).

actual operations.[26] According to Mr. Webb, "determining whether a coal unit can be shut down requires consideration of more than just economics."[27]

Q. Do you share PacifiCorp's concerns about the removal of the "must run" constraints in GRID?

A. Not to the same degree. While I agree that determining whether a unit can be shut down requires consideration of more than just economics, it's likely there are several instances where this can be done safely and where doing so would reduce overall costs. In some instances, cycling off a unit may not be justified due to the additional startup costs incurred from the cycling; however, this is something that should be quantified in a systematic way. Based on recent statements, it appears that there is no formal analysis that the Company regularly conducts to evaluate the costs and benefits of economic cycling prior to making unit commitment or dispatch decisions.[28] Even in the coal cycling study PacifiCorp provided with its testimony, it stated: "[redacted]."[29]

With respect to the 2022 TAM forecast, it is my understanding that GRID has been modified to reflect considerations regarding cycling costs and startup times.[30] The GRID

[26] PAC/100 at Webb/13:2-14:2.
[27] *Id.* at Webb/13:12-13.
[28] PacifiCorp Response to OPUC Data Request 57 (attached as Exhibit Sierra Club/104); *In the Matter of the Application of PacifiCorp (U 901-E) for Approval of its 2021 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue,* Proceeding No. A.20-08-002, Hearing Tr. Vol. 1 at 63:28-64:7 (Cal.P.U.C. May 25, 2021) [hereinafter "2021 ECAC Tr. Vol. 1"] (excerpts attached as Exhibit Sierra Club/105).
[29] PAC/107 at Webb/5.
[30] PAC/100 at Webb/15:5-16:8.

runs including these adjustments *still* led to an outcome where coal generation was substantially reduced, as was the overall NPC.

Q. Do you have any proof that there are instances where the economic losses occurred due to "must run" assumptions?

A. While very preliminary, I have conducted some analysis suggesting that must-run operation of some of PacifiCorp's coal units has led to operating losses that exceed the unit cycling costs on certain occasions.

Q. Has PacifiCorp raised concerns regarding reliability related to economic cycling of coal?

A. Yes. These are briefly described in the Confidential Economic Coal Cycling Study provided as Exhibit PAC/107. However, I did not find the level of detail in this study sufficient to properly evaluate these claims and they warrant further investigation.

Q. Will the NPC savings from the removal of the "must run" setting in GRID necessarily lead to reduced costs for PacifiCorp's customers?

A. It depends. While this change does appear to reduce forecasted NPC and thus will reduce customers' 2022 TAM costs, it does not necessarily mean that the Company will reduce coal operations in practice. To achieve those savings, PacifiCorp will also need to pursue increased cycling in its actual operations. If there is a mismatch between the forecast and actual operations, then PacifiCorp may have an opportunity to recover any additional fuel costs incurred due to "must run" operations through the PCAM, which could increase costs for customers. However, this potential cost increase would be limited due to the PCAM construct which includes a deadband up to $30 million. Thus, the total mismatch in the 2022 NPC forecast and actual operations (including any additional coal fuel burned) would need to exceed $30 million. Nevertheless, I would expect that PacifiCorp would be incentivized to pursue more economic cycling because they could capture the benefits of these savings within the PCAM's deadband, unless those benefits exceeded $30 million.

ii. *Fuel Cost Inputs for the 2022 TAM Forecast*

Q. Have you examined the specific production cost inputs within GRID?

A. Yes. In particular, I have focused my examination on the inputs for fuel costs and variable O&M costs.

Q. How does the GRID model incorporate fuel costs for each generation unit?

A. The GRID model includes two tiers of fuel costs: a "dispatch tier" and a "costing tier." The GRID model estimates plant dispatch using the dispatch tier, but calculates the NPC charged to customers (via the TAM) using the costing tier. More specifically, the model attempts to find the fleet's optimal generation to achieve the lowest feasible production cost based on the dispatch tier. The model's outputs provide the projected generation level for each plant (in MWh), which is then multiplied by the costing tier fuel price to calculate the NPC. The costing tier thus also represents the "average cost" (I will use these terms interchangeably throughout my testimony). The table below summarizes the costing and dispatch tiers as used in the GRID model for forecasting the 2022 NPC.

Confidential Table 4: GRID 2022 Tiers[31]

Coal Plant Name	GRID Costing Tier 2022 ($/MMBtu)	GRID Dispatch Tier 2022 ($/MMBtu)	Difference
Colstrip	[redacted]	[redacted]	[redacted]
Craig	[redacted]	[redacted]	[redacted]
Dave Johnston	[redacted]	[redacted]	[redacted]
Hayden	[redacted]	[redacted]	[redacted]
Hunter	[redacted]	[redacted]	[redacted]
Huntington	[redacted]	[redacted]	[redacted]
Jim Bridger	[redacted]	[redacted]	[redacted]
Naughton	[redacted]	[redacted]	[redacted]
Wyodak	[redacted]	[redacted]	[redacted]

Notably, some of PacifiCorp's coal plants have dispatch tier costs that are significantly lower than the costing tiers. This is especially true for the Jim Bridger, Colstrip, Huntington, and Hayden units.

C. Comparison of GRID Model Inputs to Actual Coal Supply Costs

Q. Have you compared the two tiers within GRID to the actual fuel prices specified in any of PacifiCorp's coal supply agreements?

A. Yes. The table below summarizes this for the Jim Bridger plant, which I have focused on because it is the largest and one of the most expensive coal fuel supplies in PacifiCorp's portfolio. Based on this analysis, the costing tier within GRID ($[redacted]/MMBtu) appears to reflect a blended cost of the different contract prices. However, the dispatch tier price is equal to the supplemental quantity from the Bridger Coal Company mine ($[redacted]/MMBtu).[32] This is significantly lower than the unit price for the two main

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[31] Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.4 [hereinafter "Confidential Attach. SC 1.4"] (attached as Exhibit Sierra Club/106).
[32] Confidential workpaper accompanying the Direct Testimony of Dana Ralston (PAC/200) "BRIDGER.xlsx" at "Detail" tab [hereinafter "Bridger workpaper (Ralston)"].

contracts ($[redacted]/MMBtu and $[redacted]/MMBtu).[33] In other words, GRID assumes that Jim Bridger dispatches with a fuel cost significantly below the estimated fuel price for the large majority of its supply.

Confidential Table 5: Assumed Jim Bridger Coal Supply for the 2022 TAM

Contract	Volume (Million Tons)[34]	Price of Delivered Coal ($/MMBtu)[35]	GRID Costing Tier ($/MMBtu)[36]	GRID Dispatch Tier ($/MMBtu)[37]
BCC (Base)	[redacted]	[redacted]	[redacted]	[redacted]
Black Butte	[redacted]	[redacted]	[redacted]	[redacted]
BCC (Supplemental)	[redacted]	[redacted]	[redacted]	[redacted]

Q. Does this mean the GRID model fuel inputs for some plants, like Jim Bridger, are not truly representative of marginal fuel costs?

A. Yes. As PacifiCorp has previously explained, the Company uses an "iterative [modeling] process" to calculate the dispatch tier pricing in order to ensure that the Company consumes the minimum coal volume in all its coal supply agreements or the target volume for affiliate mines: "If the coal volumes determined by GRID are below the minimum take requirements at a given coal plant, the incremental coal price input is adjusted down (driving up consumed coal volume as determined by GRID) until the minimum coal volume is achieved."[38] Thus, based on PacifiCorp's own admission, the dispatch tier is not truly meant to represent the marginal cost, and is instead simply adjusted to ensure that minimum quantities of coal are consumed. These minimum quantities are in turn based on either a) the terms PacifiCorp has negotiated in its coal

[33] *Id.*
[34] *Id.*
[35] *Id.*
[36] Sierra Club/106, Confidential Attach. SC 1.4.
[37] *Id.*
[38] PAC/100 at Webb/30:3-7, 30:14.

supply agreements (or expects will be included in future agreements), or b) the coal volumes PacifiCorp has planned for at its affiliate mines.

Q. Do you expect the actual generation of the unit to be inappropriately driven higher in the same manner as the GRID model projections?

A. Yes. This is because PacifiCorp similarly appears to assume artificially low fuel costs for operating decisions at some of its plants. Thus, actual generation levels (i.e. MWh) suffer from the same artificial inflation as the projected generation in GRID. Consequently, expensive coal generation displaces cheaper resources, resulting in higher retail costs than necessary.

Q. Are you concerned that PacifiCorp could rely upon similarly inflated generation projections for coal contract negotiations?

A. Hypothetically, if future coal contracts are negotiated assuming reduced dispatch costs, and correspondingly higher dispatch levels, then they could become a “self-fulfilling prophecy” of high coal demand. In my view, this would be inappropriate since at the point where fuel supply agreements are being negotiated, all of the coal-related costs (including any minimum take portion) should be considered as variable costs and modeled as such. In light of these concerns, I am encouraged that PacifiCorp seems to be taking the correct approach for many of its coal contract negotiations by using a forecasted fuel supply need that reflects the full contract costs, not a reduced dispatch cost. I discuss how PacifiCorp has addressed this for the new coal contracts the Company has recently executed in Section 5 of my testimony below. However, it is not apparent that PacifiCorp has taken this approach for the Jim Bridger plant.

D. <u>Considerations for Evaluating Coal Costs Using Marginal (Dispatch Tier) Costs Versus Average (Costing Tier) Costs</u>

Q. What is PacifiCorp's rationale for estimating generation using a dispatch tier fuel price that is lower than the actual NPC fuel cost represented by the costing tier in the GRID model?

A. As explained above, the dispatch tier is intended to better reflect the marginal or incremental cost of production at each plant after taking into account certain contract-related provisions such as take or pay obligations. For example, a coal supply agreement with a take or pay obligation would theoretically have a "zero" marginal cost until the minimum take quantity is met, above which the marginal cost would become the full contracted fuel price. Thus, for modeling purposes in GRID, PacifiCorp uses a dispatch tier price that is between zero and the full contracted fuel price. In PacifiCorp's estimation this better reflects the marginal cost throughout the year.

Q. Is this an ideal way to model PacifiCorp's fuel costs?

A. No. To appropriately model incremental fuel costs, PacifiCorp's GRID model would have both price differentiated and volume restricted tiers. Unfortunately, GRID supports only one dispatch tier. In addition to the use of a single price, however, the narrow definition of "incremental cost" within the TAM timeframe is problematic.

Q. Please elaborate on your concerns around the definition of "incremental cost" within the TAM.

A. The definition of "marginal" or "incremental" cost depends upon the timeframe being considered. In the context of real-time grid operations, the incremental cost is the cost to produce an additional MWh from a power plant that is already online and has received fuel from an existing contract. If it is presumed that all fuel supply agreements are fixed and cannot be changed, then this incremental cost can be used to develop a short-term, least-cost generation forecast for PacifiCorp's fleet. However, this definition may not fully capture certain cost considerations applicable over the course of several months or years (i.e. a long-run marginal cost). This long-run marginal cost perspective is necessary when considering new fuel supply agreements that can last several years or possible modifications to existing supply agreements. In fact, a long-run marginal cost perspective is the *only* way the prudency of a large portion of PacifiCorp's fuel costs recovered through TAM—i.e., the portion of fuel costs that are fixed due to contractual minimum take obligations (or are fixed cost components within the mine plan of an affiliate mine)—could ever be reviewed. For many coal supply agreements, the minimum take portion comprises the majority of the fuel costs. If the definition of marginal costs is so narrow as to only include short-run, real-time marginal costs, then it would appear that there is no time or place to consider the prudency of the large share of fixed fuel costs (i.e. minimum take obligations). To my knowledge, there is no other proceeding than the TAM (or possibly the PCAM) where rate recovery of these costs is examined.

Q. Based on this, how do you recommend the Commission evaluate coal fuel costs in the TAM?

A. I recommend that the Commission's evaluation consider the prudency of fuel costs not only on a short-run marginal cost basis, but also on a long-run marginal cost basis. To this end, I think the Commission should focus its evaluation on coal supplies that are either not fixed or have not yet been reviewed by the Commission. This includes: a) existing fuel supplies with no minimum take penalties, b) open positions where future fuel supplies are expected but contracts have not yet been executed, c) recently executed fuel supplies that have not previously been evaluated or approved in prior TAM proceedings (including those with a minimum take obligations), and d) existing fuel supplies that do have a minimum take obligation but could be readily revised.

Q. Are there any fuel costs included in PacifiCorp's 2022 NPC projections from coal supply agreements that meet any of these criteria—that is, the costs were not fixed (or previously reviewed by the Commission) at the time of the TAM 2022 application filing?

A. Yes, there are a few. These include supply agreements at the following plants:

Confidential Table 6: Coal Supply Agreements Without Fixed 2022 Costs at Time of TAM 2022 Application

Plant	Fuel Supply	Type
Craig	• Trapper Mine[39]	Minimum take is flexible; new contract starting [redacted][40]
Dave Johnston	• Caballo[41] • North Antelope Rochelle[42]	New contracts starting [redacted]; minimum take not previously evaluated[43]
Dave Johnston	• Unspecified PRB source	Open position for future contract (no minimum take established)[44]
Hunter	• Bronco[45] • Wolverine[46]	New contracts starting [redacted]; minimum take not previously evaluated[47]
Naughton	• Kemmerer Mine	Open position for future contract (no minimum take established)[48]
Jim Bridger	• Bridger Coal Company • Black Butte	No minimum take in Bridger Coal Company contract (existing contract) Open position for future Black Butte contract (no minimum take established)
Wyodak	• Wyodak Mine	Existing contract; [redacted][49]

[39] Sierra Club/107 (placeholder), Coal Supply Agreement with the Trapper mine (PacifiCorp has not provided Sierra Club with copies of the highly sensitive coal supply agreements to provide to the Commission. Sierra Club anticipates motioning for inclusion of highly confidential documents into the record at or before hearing.)
[40] PAC/200 at Ralston/9:9-10, 9:18-22.
[41] Sierra Club/108 (placeholder), Coal Supply Agreement with Peabody Coal Sales, LLC (Caballo Mine).
[42] Sierra Club/109 (placeholder), Coal Supply Agreement with Peabody Coal Sales, LLC (North Antelope Rochelle Mine).
[43] PAC/200 at Ralston/3:5-7, 3:14-15, 4:23-5:1.
[44] *Id.* at Ralston/6:16-17, 13 (Confidential Table 1).
[45] Sierra Club/110 (placeholder), Coal Supply Agreement with Bronco Utah Operations, LLC.
[46] Sierra Club/111 (placeholder), Coal Supply Agreement with Wolverine Fuels, LLC.
[47] PAC/200 at Ralston/7:3-9, 7:22-23.
[48] *Id.* at Ralston/19:6-8, 13 (Confidential Table 1).
[49] 2022 TAM Technical Workshop (May 14, 2021).

In addition to these, I would note that there are several existing contracts that also have clauses that might enable PacifiCorp to exit the contract or would make the minimum take unenforceable.[50] If these provisions were exercised, then they could also be added to this list.

Q. In the instances listed above, how do you think PacifiCorp should be estimating generation levels to minimize costs to its customers?

A. In these cases, it would be most prudent for PacifiCorp to estimate generation assuming the full cost associated with the costing tier (or average cost), rather than use a lower dispatch tier cost. Thus, when conducting an NPC forecast in GRID, the costing and dispatch tier values should be nearly equal. Similarly, PacifiCorp's GRID modeling used to inform initial coal contract negotiations should use the costing tier. This would be the only appropriate way to capture the true long-run marginal cost associated with these fuel sources, and their ultimate cost to PacifiCorp customers. Some of these fuel supplies include new contracts with minimum take obligations (e.g. Dave Johnston, Hunter, Craig)[51] that have not yet been evaluated by the Commission. Others are open positions for future contracts that have not even been negotiated, let alone evaluated by the Commission (e.g., Jim Bridger, Naughton, Dave Johnston). Presumably PacifiCorp has (or will have) negotiated the terms of these contracts with the best interests of its customers in mind, in which case it would have considered the full range of costs its

[50] PacifiCorp Response to Sierra Club Data Request 1.28 (PacifiCorp indicated that coal supply agreements for the Naughton, Huntington, and Colstrip plants currently have provisions allowing the Company to avoid minimum take obligations in the event that actual or prospective environmental legislation or regulation would impact coal-burning generation.). The public version of this response is included in Exhibit Sierra Club/103 and all confidential data responses referenced in this testimony (including the unredacted version of 1.28) are compiled and attached as Exhibit Sierra Club/112.]
[51] PAC/200 at Ralston/4:23-5:8, 8:5-9, 10:3-5.

customers would be subject to including any minimum take component. At the point in time of contract negotiations, the take-or-pay portion is not a previously incurred (or "sunk") cost. This suggests that, during the negotiation phase, PacifiCorp should have considered the full costing tier price for estimating the generation quantity that could reasonably be supported by the new contracts.

Q. What if use of the costing tier for these new contracts leads to generation levels less than the minimum take quantity?

A. If the generation quantity estimated using the costing tier price was less than what the minimum take provisions requires, then executing the contract would not have been prudent under the terms PacifiCorp negotiated. Similarly, for the purposes of the TAM, the generation quantity estimated in GRID for expected or newly contracted fuel supplies should reflect the full costing tier price. If GRID showed that the minimum take provision for a new contract was not met, the correct solution is not to tinker with the inputs to ensure that minimum is met. Instead, this result simply reflects the fact that the contract was entered imprudently and the Company should be responsible for any shortfall payments that occur, not its customers.

Q. For any of the fuel supplies at the six plants listed in the table above, has PacifiCorp correctly assumed that the dispatch tier prices are equivalent to the costing tier when modeling 2022 NPC in GRID?

A. Yes, but only for the [redacted] supply fueling the [redacted] plant. For all the other plants the dispatch tier is lower than the costing tier. However, I will note that the dispatch and costing tiers are relatively close for several of the plants including [redacted], and [redacted].

Q. Of those six plants listed in the table above, are there any you are especially concerned about how they were modeled in GRID for the 2022 TAM?

A. Yes. I'm most concerned about the how the coal supply at Jim Bridger has been modeled, which I will discuss at length in Section 6 of my testimony. For five of the six plants listed in the table, the dispatch tier and costing tier values were within [redacted] percent of each other. Meanwhile, at Jim Bridger the dispatch tier is [redacted] percent lower.

Q. Do you have any recommendations for how the GRID model should be adjusted for the purposes of forecasting NPC in the 2022 TAM?

A. My primary recommendation would be to update the dispatch tier cost inputs for Jim Bridger so that they represent the true 2022 marginal cost as I've outlined in this section and in Section 6.

5. Review of PacifiCorp's Coal Contracting Practices and New/Future Coal Supply Agreements

A. Overview of New Coal Contracts Executed Since the 2021 TAM Proceeding

Q. Since the close of the 2021 TAM, has PacifiCorp entered into any new coal supply agreements?

A. Yes. According to Mr. Ralston's testimony, the Company has executed five new coal supply agreements since the 2021 TAM. Two relate to the Dave Johnston plant, two relate to the Hunter plant, and one to the Craig plant.[52]

[52] PAC/200 at Ralston/2:19-21.

Q. Do you recommend that the Commission make a prudency determination on the new coal supply agreements in this proceeding?

A. Yes. Commission review of PacifiCorp's coal supply agreements is critical, as minimum take provisions contained in these contracts have a large impact on PacifiCorp's forecasted and actual dispatching decisions, and resulting costs to customers.

Q. How do you recommend that the Commission evaluate the new coal supply agreements?

A. There are many aspects of the coal supply agreements that deserve review. In particular, I recommend that the Commission pay close attention to any minimum take requirement contained in the new coal supply agreements. As discussed throughout my testimony, multi-year coal supply agreements with inflexible minimum purchase requirements leave the Company with no flexibility to adjust to evolving market conditions or new resource additions. As such, I believe the Commission should conduct additional scrutiny for any coal supply agreements that include a minimum take quantity that is over 50 percent of the forecasted need. This scrutiny could include a requirement for PacifiCorp to provide a detailed explanation for why a minimum tonnage threshold above 50 percent (or would reach 50% in combination with other existing minimums) of the forecasted generation is prudent. During this evaluation, the Commission should review not only whether a coal supply agreement's minimum take requirement exceeds the 50 percent threshold, but also how PacifiCorp forecasted the anticipated generation requiring the coal supply.

Q. How does PacifiCorp forecast anticipated generation in preparation for coal contract negotiations?

According to OPUC 72,[53] the negotiations for the new agreements at Dave Johnston and Craig were based upon a generation forecast that was part of the overall fueling budget for the Company initially developed in July 2020 and further updated in December 2020. For Dave Johnston, these generation forecasts were developed using GRID (and presumably GRID was used for Craig as well).[54] For the new Hunter contracts, the generation forecasts were developed using the Company's May 2020 GRID model runs developed for avoided cost.[55]

Q. Do you have any concerns about the accuracy of these forecasts?

A. Yes. There are several facts that lead me to believe that the generation forecasts conducted in preparation for these contract negotiations may be higher than necessary. These include some of the following information provided by PacifiCorp:

- SC 8.9(b) (CA ECAC 2021)[56] states that: "In addition to the modeled generation output reported by GRID, additional expected generation was added to account for the fuel requirement of the joint owners at Hunter, ramping requirements not captured within the GRID logic, and expected energy imbalance market (EIM) dispatch."

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[53] PacifiCorp Response to OPUC Data Request 72 (attached as Exhibit Sierra Club/113).
[54] *Id.*
[55] *Id.*
[56] A.20-08-002, PacifiCorp Response to Sierra Club Data Request 8.9 (Cal.P.U.C. Feb. 25, 2021) [hereinafter "ECAC Sierra Club 8.9"] (attached as Exhibit Sierra Club/114).

- SC 8.9(c) (CA ECAC 2021) states that: "Hunter Unit 1 and Hunter Unit 2 were allowed to cycle in the spring, consistent with assumptions previously used in Oregon Transition Adjustment Mechanism (TAM) filings[,]" indicating that the forecast for 2021 had "Must Run" constraints applied to all non-spring months, and year-round for Hunter Unit 3.
- SC 8.9(c) (CA ECAC 2021) indicates that different assumptions were made when forecasting the generation in Hunter and Dave Johnston, showing that there is no single forecast, but every unit's generation is projected separately.
- OPUC 72 states that: "Based on the December 9, 2020 top-side adjustments, the coal generation forecast for the Dave Johnston plant for 2021 was reduced . . . in an effort to increase the coal generation forecasts of the Hunter plant and the Huntington plant. Note: the December 9, 2020 updated coal generation forecast also started with a GRID run, and then was adjusted at the report level to keep coal consumption constraints intact."
- OPUC 71-1[57] shows a [redacted] percent increase in the forecasted coal consumption of Jim Bridger between the June and December forecasts without any explanation.

B. Evaluation of Open Positions for Future Contracts in 2022 That Have Not Been Executed

Q. Can you summarize the Company's currently open positions for coal supply in 2022?

A. PacifiCorp currently has open positions for a portion of its 2022 fuel supply at the Jim Bridger and Dave Johnston plants. It also has an open position for all of its 2022 fuel supply at the Naughton plant.

[57] Confidential Attachment OPUC 71-1 to PacifiCorp Response to OPUC Data Request 71 [hereinafter "Confidential Attach. OPUC 71-1"] (attached as Exhibit Sierra Club/115).

Q. Is PacifiCorp seeking to recover costs for fuel associated with these open positions through the 2022 TAM, despite not having coal supply agreements in place?

A. Yes. Specifically, PacifiCorp is projecting the following forecasted NPC costs for these open positions:

Confidential Table 7. Summary of Open Position (Uncontracted) Fuel Supply Costs Assumed in the 2022 NPC Corecast

Fuel Supply	**Plant**	**2022 NPC Forecast**
Lighthouse Resources/Black Butte (excludes 2021 deferrals)	Jim Bridger	[redacted][58]
Westmoreland/Kemmerer	Naughton	[redacted][59]
Unspecified PRB Mines	Dave Johnston	[redacted][60]
Total		[redacted]

Thus, about [redacted] percent of PacifiCorp's projected coal fuel costs or about [redacted] percent of total 2022 NPC are attributable to uncontracted, open position fuel sources.

Q. What fuel costs did PacifiCorp assume for these three open positions in its GRID model?

A. For Kemmerer (Naughton), the assumed price was $[redacted] per ton for [redacted] tons.[61] According to PacifiCorp this pricing is "an estimate based on preliminary discussions with the Kemmerer mine."[62] For Black Butte/Jim Bridger deliveries in 2022 the assumed

[58] Bridger workpaper (Ralston) at "BlackButte Detail" tab.
[59] PAC/102 at Webb/5.
[60] Confidential workpaper accompanying the Direct Testimony of Dana Ralston (PAC/200) "JOHNSTON.xlsx" at "Detail" tab.
[61] Sierra Club/112, Confidential PacifiCorp Response to Sierra Club Data Request 1.14; PAC/200 at Ralston/19:11.
[62] PAC/200 at Ralston/19:11-12.

cost was $[redacted] per ton for [redacted] tons.[63] This includes [redacted] tons from a future supply agreement, as well as [redacted] tons that were deferred from 2021 to 2022.[64] It is unclear from the testimony presented how PacifiCorp estimated pricing for the portion from the future supply agreement. For coal from the Powder River Basin ("PRB") to supply Dave Johnston, the assumed price was $[redacted] per ton for [redacted] tons.[65] As PacifiCorp explained, this pricing reflects the average 2022 forward price of PRB coal as published by Coal Daily.[66]

Q. In developing the TAM 2022 forecast, did PacifiCorp assume that coal supply from these three sources would include minimum take quantities?

A. Yes. According to SC 1.6, PacifiCorp assumed minimum take quantities for each of these sources and used its "iterative process" to adjust GRID inputs to ensure that these quantities would be consumed.[67] For example, for Jim Bridger, the assumed minimum quantity includes the deferred [redacted] tons, and assumed [redacted] tons from the new Black Butte supply, and [redacted] tons from the Bridger Coal Company mine.[68]

Q. Does this contrast with PacifiCorp's business planning for future contracts (i.e. open positions)?

A. Yes. During its business planning, my understanding is that the company considers the full range of costs for future contracts and does not treat any of these as sunk prior to

[63] *Id.* at Ralston/15 (Confidential Table 3).
[64] *Id.* at Ralston/18:11-15.
[65] Sierra Club/112, Confidential PacifiCorp Response to Sierra Club Data Request 1.14; PAC/200 at Ralston/20:10.
[66] PAC/200 at Ralston/20:9-11.
[67] Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.6 [hereinafter "Confidential Attach. SC 1.6"] (attached as Exhibit Sierra Club/116).
[68] PAC/200 at Ralston/18:11-15.

contract execution. As the Company recently testified regarding its analysis of new coal supplies for Hunter: "The modeled incremental fuel costs for Hunter were consistent with the full delivered contract cost (or costing tier) for all volumes and no minimum take obligation was applied to the Hunter plant. As a result, the model results reflect the full range of costs contemplated in the Hunter contracts, and not just the incremental cost component."[69]

Q. Do you agree with PacifiCorp's modeling choice in the TAM 2022 forecast to treat portions of open positions as already sunk costs?

A. No. Even if PacifiCorp's argument about minimum-take payments being sunk costs were accepted for some of the older supply agreements in place, this approach is absolutely incorrect in the case of open positions, where fuel costs are not sunk yet. At the time of the TAM 2022 modeling in GRID, Jim Bridger's 2022 coal supply included a minimum quantity of [redacted] tons from the Black Butte mine which were deferred from 2021. This might reasonably be considered a minimum quantity for Jim Bridger. However, the entire plant is assumed to have a minimum consumption of [redacted] tons which I do not think is reasonable, as PacifiCorp has not yet entered into a contract committing itself to purchase any additional quantity of coal. Moreover, treating the full [redacted] tons as fixed or sunk costs would require Oregon ratepayers to cover costs for fuel contracts where no details are yet known to the Commission and, if reviewed, may ultimately be found to be imprudent. Additionally, the iterative process that PacifiCorp uses to force GRID to consume the minimum take tonnage is even more extreme for Jim Bridger than

[69] A.20-08-002, Rebuttal Testimony of Daniel J. MacNeil on Behalf of PacifiCorp (PAC/1000) at MacNeil/15:5-9 (Cal.P.U.C. May 2021).

it is for other plants. Specifically, PacifiCorp customers pay approximately [redacted]/MMBtu to consume the vast majority of coal at Jim Bridger, but the Company models its operations using a price of only [redacted]/MMBtu. This price discrepancy is further addressed in section 6-B.

Q. What is your recommendation for the recovery of costs associated with those open positions?

A. At present, there is substantial uncertainty around these future contracts regarding their price, term, minimum take quantity, and other key provisions that might affect the ultimate fuel costs that PacifiCorp will seek to recover from its customers.

In the case of Black Butte, where there is both a very high estimated price and the availability of an alternate fuel source, it is not even clear whether a new contract will actually be necessary or prudent. In the case of Naughton, PacifiCorp was unwilling to provide any communications regarding their preliminary discussions with the supplier.[70]

Given these concerns, I recommend that the forecasted costs associated with these open positions only be included in the 2022 TAM on an interim basis until PacifiCorp is able to provide specific details about these agreements for the Commission's review. Based upon this subsequent review, appropriate revisions to the 2022 TAM rates may be warranted and should be made at that time. This could include a new NPC forecast using the final contract terms and pricing.

[70] Sierra Club/103, PacifiCorp Response to Sierra Club Data Request 2.19.

C. Evaluation of Minimum Take Quantities in New Coal Supply Agreements for the Hunter Plant

Q. Have you evaluated the minimum take provisions for any of PacifiCorp's newly executed coal contracts?

A. Yes. Specifically, I focused my review on the new contracts to supply the Hunter plant.

Q. How do the minimum take quantities in the new Hunter coal contracts compare to the future generation levels estimated by PacifiCorp?

A. At the pricing level ultimately set for the Hunter contracts (~$[redacted]/MMBtu),[71] PacifiCorp asserts that the "budgeted and updated forecasted generation showed that the Hunter plant would consume considerably more than the combined [redacted] minimum purchase requirement for coal under contract in 2021."[72]

Q. What did PacifiCorp forecast for coal consumption at Hunter before and after executing this contract?

A. Based on OPUC 71-2, it appears that PacifiCorp initially forecasted annual average consumption at Hunter ranging from [redacted] to [redacted] tons over the 2021-2023 period.[73] Thus, a minimum of [redacted] tons would correspond to [redacted] percent of the estimated annual consumption. My understanding from OPUC 72 is that this forecast was conducted in the May 2020 timeframe. Later, in PacifiCorp's December 2020 budgeting forecast update (provided in OPUC 71-1[74]), the Company forecasted Hunter's consumption to be closer to the lower end of the initial range or about [redacted] tons

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[71] Confidential workpaper accompanying the Direct Testimony of Dana Ralston (PAC/200) "HUNTER.xlsx" at "Hunter Detail" tab [hereinafter "Hunter workpaper (Ralston)"].
[72] PAC/200 at Ralston/9:2-5.
[73] Confidential Attachment OPUC 71-2 to PacifiCorp Response to OPUC Data Request 71 (attached as Exhibit Sierra Club/117).
[74] *See* Sierra Club/115, Confidential Attach. OPUC 71-1.

(i.e. the minimum equates to [redacted] percent of total). These forecasts occurred prior to the contract being executed in early 2021. Just a few months later, as part of its application in this case (filed April 2021) PacifiCorp's GRID forecast for 2022 shows annual consumption at the Hunter plant will be only slightly above the contracted minimum take quantity (i.e., [redacted]).[75] This is true even though the dispatch tier price assumed for the 2022 TAM application was adjusted to be lower than the contractual price.[76] The forecast PacifiCorp is using in this proceeding now shows the Hunter minimum quantity to be approximately [redacted] percent of the total generation forecast.

Q. Do you have any explanation for this change in forecasted consumption?

A. While there are likely several factors at play, the most plausible explanation in my view is that the initial Hunter forecast and the December 2020 budgeting forecast included "must-run" constraints and other post-modeling adjustments as described in OPUC 72[77] that likely increased the forecasted coal consumption, whereas the April 2021 forecast for the 2022 TAM did not include these. The discrepancy shows that the forecasted generation is very sensitive to the Company's pre- and post- modeling assumptions.

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[75] Sierra Club/116, Confidential Attach. SC 1.6.
[76] Sierra Club/106, Confidential Attach. SC 1.4.
[77] Sierra Club/113, PacifiCorp Response to OPUC Data Request 72.

Q. Has PacifiCorp always been accurate in its estimates of future generation needs when developing a fuel plan?

A. No. For example, in 2016 and 2017, the Jim Bridger plant consumed approximately [redacted] percent less[78] than was projected in the GRID model included in the 2015 "PacifiCorp's Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant."

Highly Confidential Table 8: Variance in Projected and Actual Tonnage Consumed at Jim Bridger[79]

	2016	2017
2015 Base Operating Plan for Jim Bridger Plant (tons)	[redacted]	[redacted]
Actual Coal Tonnage Consumed at Jim Bridger	[redacted]	[redacted]
Variance in Tonnage	[redacted]	[redacted]

Consequently, in its 2018 long-term fuel supply plan, PacifiCorp revised its GRID modeling and forecasted significantly different coal requirements for later years, revising them [redacted] by over [redacted].[80]

Q. Is there any additional evidence that PacifiCorp would be at risk of not meeting the minimum take at Hunter?

A. Yes. According to the Company's own analysis in GRID provided in its Supplemental Testimony in the California 2021 ECAC proceeding (which is analogous to TAM), the model inputs required an "iterative adjustment to the incremental prices at Hunter in

[78] Attachment "PacifiCorp Confidential Long-Term Fuel Supply Plan for Jim Bridger Plant" to PacifiCorp Response to Sierra Club Data Request 1.31 (The plan was viewed by Sierra Club over Skype and PacifiCorp has not provided Sierra Club with copies of the unredacted, highly sensitive version to provide to the Commission. Sierra Club anticipates motioning for inclusion of highly confidential documents into the record at or before hearing.) (The redacted version was provided as Exhibit SC-6 to the Prepared Direct Testimony of Ed Burgess in A.20-08-002 and is attached here as Exhibit Sierra Club/118.).
[79] *Id.*
[80] *Id.* at Appendix A (forecasted Generation in 2015 and 2018 Fuel Plans for Jim Bridger).

order that it too would satisfy all contractual obligations."[81] In other words, the fuel price at Hunter had to be manually adjusted, decreasing it from the contract price, just to ensure the minimum quantity was met. Similarly, in this proceeding, PacifiCorp ended up using a dispatch tier cost in GRID for Hunter that is lower than the costing tier.[82] If PacifiCorp had contracted for a more appropriate minimum take quantity, one well below Hunter's generation requirements, then these adjustments would not be needed.

Q. In light of this, does the Hunter minimum take level seem reasonable to you?

A. No. At the time the contract was executed, PacifiCorp projected the minimum take level at the Hunter plant to be [redacted] percent of the plant's annual coal consumption, which is already quite high. Just four months later that share has now grown to be [redacted] percent. In my view, this reflects the general industry trend towards lower coal generation than forecast[83] and is a clear example of why companies like PacifiCorp should be especially careful in avoiding minimum take quantities that are too high. Given the potential risks of penalty payments, I recommend that utilities should seek to avoid entering contracts where the minimum take provisions exceed 50 percent of projected consumption.

Q. Is PacifiCorp at risk of not having enough fuel supplied to the Hunter plant if the minimum take is set too low?

A. No, I don't believe so. PacifiCorp has a very large stockpile of existing coal at the Hunter plant, which equates to approximately [redacted] tons.[84] This should be sufficient to

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[81] A.20-08-002, Corrected Supplemental Direct Testimony of David G. Webb (PAC/600), at Webb/4:5-6. (attached as Exhibit Sierra Club/119).
[82] Sierra Club/106, Confidential Attach. SC 1.4.
[83] *Annual Energy Outlook Retrospective Review*, U.S. Energy Information Administration, Table 1 (Dec. 29, 2020), *available at* https://www.eia.gov/outlooks/aeo/retrospective/ (the "Total Coal Consumption" line showing that 79% of Annual Energy Outlook forecasts since 1994 were overestimated).
[84] Hunter workpaper (Ralston).

account for any unexpected discrepancies between the delivered volumes and plant generation needs within a given year.

Q. Do you have any additional recommendations regarding the Hunter minimum take level?

A. Yes. If consumption levels ultimately do fall below the contractual minimum, then PacifiCorp should be responsible for any shortfall payments (rather than its customers), since those payments stem directly from PacifiCorp's decision to enter the current contract instead of a contract with a lower minimum take. Notably, PacifiCorp may already have some exposure to the cost of shortfall payments due to the PCAM construct and related deadbands. However, to the extent that the shortfall payments exceed these deadbands, then I believe that PacifiCorp should still be responsible for those payments.

Q. Do you have any other recommendations for how PacifiCorp should be forecasting anticipated generation from its coal plants?

A. Yes. As noted elsewhere in my testimony, when negotiating a new coal contract, PacifiCorp should forecast anticipated generation based on the full cost of the coal being purchased, *i.e.*, the incremental/dispatch tier and the average/costing tier should be equal. Utilizing a lower incremental cost of coal in this context would not represent the true cost that Oregon ratepayers will pay and causes the model to forecast more coal-fired generation than is economically reasonable. Before signing a new coal contract, there is no reason to assume that any portion of the coal costs are "sunk" or fixed and thus no reason to use a different incremental coal fuel price.

Q. Did PacifiCorp apply your recommended price modeling approach to the new contracts at Hunter?

A. Based on my interpretation of OPUC 72 and other recent data responses,[85] it appears that PacifiCorp did take this recommended pricing approach for modeling the Hunter contracts prior to execution and should be commended for doing so.[86] However, it is not apparent to me that this is standard practice for all of PacifiCorp's coal contract negotiations. As such, I recommend that the Commission establish on a going forward basis that any new fuel supply agreement executed by PacifiCorp or any other utility must be evaluated based the full contract cost as described above.

Q. Do you have any other concerns about PacifiCorp's generation forecasts related to these contracts?

A. I am concerned that in the process of estimating generation levels, a large portion of PacifiCorp's coal fleet was set as "must run" and not permitted to cycle. I'm especially concerned about the fact that in the forecast for the Hunter contract, Hunter Units 1 and 2 were only allowed to cycle in the spring. I believe they should be permitted to cycle year-round and that Hunter Unit 3 should also be allowed to cycle. Additionally, PacifiCorp utilized GRID to model anticipated coal generation, but there is no indication that the Company completed an alternatives analysis that would have scrutinized whether it was in ratepayers' interest to enter into a new multi-year contract versus soliciting pricing data from other potential new generation sources other than market purchases.

[85] Sierra Club/113, Confidential PacifiCorp Response to OPUC Data Request 72; Sierra Club/114, ECAC Sierra Club 8.9(c).
[86] *See* Sierra Club/114, ECAC Sierra Club 8.9(c) ("the fuel price points evaluated in the Hunter analysis are representative of a contract with identical average and incremental costs").

D. <u>Evaluation of Other Contracting Practices</u>

Q. What other coal contract provisions do you believe are important for the Commission to review?

A. The Commission should review whether PacifiCorp's coal supply agreements contain renegotiation provisions that would allow the Company to avoid or reduce minimum take provisions if certain conditions arise, including when reducing coal purchases would be in the best interest of ratepayers or required by new regulatory requirements. PacifiCorp has been able to include these types of provisions in previous contracts, and the Commission should consider their inclusion as part of contract negotiation best practices. Additionally, some utilities in the region have coal supply agreements that include specific provisions for termination within a certain timeframe of an announced plant closure.

From a practical standpoint, the Commission will need to continuously review whether PacifiCorp is taking advantage of these provisions when appropriate. The Commission may accomplish this goal by directing PacifiCorp to review its coal contracts with renegotiation provisions and provide the Commission with a report analyzing whether such renegotiations would be in the best interest of Oregon ratepayers as part of its yearly TAM application.

Q. Are there any other contract best practices that you would recommend?

A. Yes. First, due to rapidly evolving market conditions, PacifiCorp should seek to only enter into short-term coal supply agreements, ideally no more than 1-2 years. Locking Oregon customers into multi-year contracts, particularly with high minimum take provisions, hinders the Company's ability to adapt to changing market conditions and integrate increasing levels of renewable energy resources. Second, the Commission should require that PacifiCorp provide copies of its coal supply agreements and affiliate mine plans to the Commission as a standard part of its review of all future TAM application filing. Routinely providing the Commission and intervening parties who have signed the applicable protective order with copies of these contracts will eliminate an unnecessary burden on Commission review. Without access to the contracts themselves, it is impossible to truly scrutinize whether the contracts are just and reasonable. While these contracts may be commercially sensitive, the Commission has procedures in place to protect the Company's confidential information.

Q. What is the length of PacifiCorp's new coal supply agreements?

A. The Dave Johnston contracts are both [redacted] in length.[87] The Bronco Utah Operations LLC contract for the Hunter plant is [redacted] in length and the Wolverine Fuels LLC contract for the Hunter plant is [redacted] in length.[88] The contract with the Trapper mine for the Craig plant is [redacted] in length.[89]

Q. Do you have an opinion on the prudency of the new coal supply agreements that PacifiCorp has presented in this proceeding?

A. Yes. In my opinion, PacifiCorp has not done enough to demonstrate that the coal supply agreements at Hunter are prudent. First, as discussed above, the agreements include very high minimum take provisions. Second, although company witness Dana M. Ralston claims that before the two new agreements were signed, the Company completed an

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[87] PAC/200 at Ralston/3:14-15.
[88] *Id.* at Ralston/7:7-9.
[89] *Id.* at Ralston/9:10.

updated generation forecast for the plant that resulted in coal consumption considerably more than the combined [redacted] ton minimum purchase requirement for coal under contract in 2021,[90] the Company still had to adjust the dispatch tier (below contract levels) through its iterative GRID process to ensure that even this minimum take quantity is consumed.[91] This suggests to me that the executed minimum take quantity is at risk of not being met. Third, the 2022 TAM forecast, which removes the must run constraint, shows that Hunter's forecasted generation levels are extremely close to the minimum take quantity. Fourth, the Company's new contracts last from [redacted]. While this is certainly an improvement from previous contracts, the length still limits PacifiCorp's flexibility regarding future fuel and resource procurement practices. Finally, before entering into multi-year contracts, it would be appropriate for PacifiCorp to complete a comprehensive analysis of potential generation alternatives. There is no indication that PacifiCorp has done so.

6. <u>Analysis of Bridger Coal Company Expenses in TAM 2022</u>

A. <u>Marginal Fuel Costs and Minimum Tonnages for Coal Supplying Jim Bridger</u>

Q. Despite your concerns about PacifiCorp's approach to selecting GRID inputs (i.e., the "iterative process"), do you believe the dispatch tier prices used by PacifiCorp could be seen as a very rough approximation of short run marginal costs, once take or pay obligations factored in?

A. In some cases, yes, but not in all cases. I understand the logic of using a lower dispatch tier price in cases where an *existing* supply agreement contains a take or pay provision.

[90] *Id.* at Ralston/9:1-5.
[91] Sierra Club/106, Confidential Attach. SC 1.4.

However, it would not be logical to do this where there is no existing agreement or there is no minimum take in effect. This inconsistency is most apparent at the Jim Bridger plant, where the 2022 dispatch tier is [redacted] percent lower than the costing tier in GRID. At this plant, PacifiCorp anticipates that it will have two main suppliers in 2022: BCC and Black Butte. The current Black Butte coal supply agreement expires in December 2021. Thus, for 2022, no third-party supply agreement is in effect and there is no existing minimum take obligation for 2022.[92] Furthermore, as an affiliate mine, coal supplied from BCC does not include a minimum take provision. Despite the lack of any minimum take quantities, the Company uses a single dispatch tier fuel price at Jim Bridger that deviates *significantly* from what I understand to be the true marginal cost in 2022 of either the BCC or the Black Butte coal supply.

Q. What are the implications of the fact that neither the BCC nor the Black Butte coal supplies have an existing minimum take penalty for 2022?

A. There are several implications. First, it gives PacifiCorp the flexibility to consider ramping down consumption from these sources in 2022 if doing so would reduce costs for its customers, without needing to consider any take or pay penalties since these do not exist yet. Second, the marginal or incremental cost of production represented by the dispatch tier price for Jim Bridger should be nearly equal to the average or costing tier price. In other words, no adjustments are needed to account for any minimum take quantities.

[92] Delivery of [redacted] tons from the expiring contract was deferred to 2022, but this is only expected to last for a few months.

Q. Do PacifiCorp's assumptions for Jim Bridger fuel costs in the GRID model reflect these facts?

A. No. PacifiCorp has chosen GRID model assumptions that do not reflect these facts. Instead, it applies a single dispatch tier price for *all* of the fuel consumed at Jim Bridger that is [redacted] percent lower than the BCC base contract price and [redacted] percent lower than the assumed Black Butte price, as presented in Mr. Ralston's confidential workpapers.[93]

Q. Why is it concerning to you that PacifiCorp uses a dispatch tier fuel price for Jim Bridger that is so much lower than the costing tier?

A. This is concerning because in cases with no existing minimum take provision, the dispatch tier price should be equal to the costing tier. Additionally, the actual cost of coal fuel at Jim Bridger in 2022 is expected to be one of the most expensive in PacifiCorp's fleet, yet these full costs are not correctly represented in PacifiCorp's GRID dispatch model. Finally, the lack of an existing minimum take penalty for 2022 means that no such minimums should be included in any of PacifiCorp's 2022 NPC forecasts. However, it appears that PacifiCorp's analysis has inexplicably included minimum take quantities in its analysis of the BCC and Black Butte fuel sources.

Q. What minimum quantity of fuel consumption has PacifiCorp assumed for Jim Bridger in 2022?

A. According to SC 1.6, it assumes a minimum quantity of about [redacted] MMBtus—the highest of any plant in its fleet.

[93] *See* Bridger workpaper (Ralston) at "Detail" tab.

Q. Despite this purported minimum, does PacifiCorp actually have flexibility to reduce 2022 coal consumption from Black Butte?

A. Yes. Because there is an open position with no existing contract, the Company should have flexibility to negotiate for a smaller contract minimum at Black Butte if necessary. Alternatively, the Company could decide not to enter a new contract at Black Butte if it is not economic to do so.

Q. Does PacifiCorp have flexibility to reduce 2022 coal consumption from BCC?

A. Yes. In direct testimony in the 2021 TAM proceeding the Company's witness stated the following: "As an indirect subsidiary of the plant owners, with no marketing operations, Bridger Coal Company coal deliveries can be flexed down to satisfy the Jim Bridger plant's requirements, as necessary. The flexibility of Bridger Coal Company allows PacifiCorp to mitigate against the risk of minimum take penalties associated with the fixed tonnage volumes from the Black Butte Coal Company."[94]

Q. Does PacifiCorp appear to be taking full advantage of this ability to flex down coal from BCC?

A. No. Instead, PacifiCorp consistently does the opposite by seeking to add supplemental quantities from BCC that are entirely optional. Moreover, in its 2021 NPC modeling efforts (when Black Butte minimums were in effect) PacifiCorp appears to have taken purposeful steps to avoid reducing coal quantities from BCC, instead reducing quantities from Black Butte, thereby triggering unnecessary take or pay penalties that skew the

[94] Docket UE 375, Direct Testimony of Dana M. Ralston (PAC/300) at Ralston/3:17-21 (Feb. 2020).

findings.[95] For example, this appears to be the case for the Average Cost GRID model runs PacifiCorp performed in the 2021 TAM proceeding as well as in this proceeding.[96] This is discussed further below in section 6-C.

Q. Has PacifiCorp described any limitations on its ability to flex down coal from BCC?

A. Yes. PacifiCorp has described limitations in flexing down production from the BCC underground mine too quickly due to certain technical requirements and safety concerns.[97] However, since the underground mine is due to close at the end of this year, these limitations should not apply in 2022. At that point, BCC operations will consist exclusively of the surface mine which does not have similar limitations.

Q. PacifiCorp has previously represented that it must meet its level of "scheduled production" at BCC in each year. Do you agree with this?

A. No. First, the level of "scheduled production" at BCC is something that PacifiCorp self-determines as the majority owner of the mine, in consultation with the mine's minority owner Idaho Power Company. Knowing the full cost burden that BCC coal imposes on its electricity customers, PacifiCorp could have taken proactive steps well before this proceeding to reduce the level of scheduled production in 2022.

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[95] *See*, *e.g.*, A.20-08-002, PacifiCorp's Response to Sierra Club Data Request 8.7(b) [hereinafter "ECAC Sierra Club 8.7"] (attached as Exhibit Sierra Club/120).
[96] Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 2.3 [hereinafter "Confidential Attach. 2.3"] (attached as Exhibit Sierra Club/121).
[97] Sierra Club/105, 2021 ECAC Tr. Vol. 1 at 107:5-14.

Q. Do you accept PacifiCorp's rationale that "[t]o fully evaluate the impact of dispatching the Jim Bridger plant on an average cost basis, the company would need to develop and complete a long-term fueling evaluation."?[98]

A. No. PacifiCorp has known about the high cost of BCC coal for multiple TAM cycles and would have had plenty of time prior to the 2022 TAM to develop a long-term fueling evaluation that would accommodate lower production levels. In fact, the high cost was evident as early as PacifiCorp's 2019 forecast[99] (and possibly sooner), not long after the most recent long-term fuel plan for BCC was being developed.

Q. Do you have any recommendations about how PacifiCorp should evaluate BCC coal going forward?

A. Given the high cost, it may be prudent for PacifiCorp to evaluate accelerated closure of the mine. Meanwhile, the Commission should consider whether it would have been prudent for PacifiCorp to have considered this option well in advance of the 2022 TAM.

i. Fixed BCC Costs

Q. Has PacifiCorp described any limitations on its ability to reduce 2022 TAM NPC costs for BCC coal if production is flexed down?

A. Yes. PacifiCorp has explained that some of the BCC coal costs recovered through the TAM are fixed costs that could not be avoided if production is flexed down. As such, when PacifiCorp conducts GRID model runs with reduced generation at Jim Bridger, the Company also makes subsequent adjustments to add back in some of these fixed costs to

[98] Sierra Club/120, ECAC Sierra Club 8.7(b).
[99] Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 2.7 (attached as Exhibit Sierra Club/122).

the NPC through a "reaveraging" step. PacifiCorp described this process during the workshop held on May 14, 2021 as part of this proceeding.

Q. Has PacifiCorp provided any accounting of what portion of BCC coal costs recovered through the TAM it considers to be variable and what portion it considers to be fixed?

A. In response the SC 2.5, the company provided a breakdown of 2022 TAM costs from BCC coal that it considers to be fixed, totaling about $[redacted].[100] This amounts to about [redacted] percent of the total $[redacted] that is PacifiCorp's estimated share of BCC costs in 2022. Thus, based on PacifiCorp's own accounting at least [redacted] percent of the BCC coal costs are variable and could therefore be avoided if BCC coal consumption was ramped down.

Confidential Table 9. Breakdown of 2022 BCC Coal Cost Components as Estimated by PacifiCorp[101]

Component	**Cost**	**% of Total 2022 BCC Costs**
Management Fee	[redacted]	
Depreciation		
Depletion		
Insurance/Bonds		
Property Tax		
Final Reclamation Contributions		
Total Fixed		
Excl. Reclamation		
Total Variable		
Total BCC Costs		

[100] Sierra Club/112, Confidential PacifiCorp Response to Sierra Club Data Request 2.5(c).
[101] *Id.*

Q. What are the most significant components of the costs PacifiCorp claims are fixed?

A. PacifiCorp identifies six BCC cost items as fixed: Management Fee, Depreciation, Depletion, Insurance/Bonds, Property Tax, and Final Reclamation Contributions. Of these the vast majority (~$[redacted]) are comprised of two items: Depreciation and Final Reclamation.

Q. Do you agree with PacifiCorp's treatment of depreciation as a fixed cost that should be recovered through the TAM?

A. Yes, depreciation is a fixed cost. However, I will note that it is more common for depreciation costs to be recovered through base rates, rather than fuel cost adjusters like the TAM. Additionally, PacifiCorp already recovers significant fixed costs associated with the Bridger mine through base rates. As such, I recommend that the Commission conduct a comparison of these two cost recovery mechanisms to ensure that there are no duplicative depreciation costs for the BCC mine being recovered in both base rates and the TAM.

Q. Do you agree with PacifiCorp's treatment of final reclamation as a fixed cost that should be recovered through the TAM?

A. I agree that final reclamation costs are unavoidable, however I do have some concern about PacifiCorp's treatment of these costs in the 2022 TAM context. First, reclamation costs are at least partly based upon the additional volumes of coal that are yet to be mined. As such, they are not entirely fixed. Second, I suspect that the reclamation costs anticipated for the 2022 TAM may be higher than they otherwise would have been if PacifiCorp had taken proactive steps to collect additional reclamation funds in earlier years. As such, the fact that PacifiCorp intends to collect such a large sum for reclamation in 2022 may be an artifact of its past management practices. In fact, it is possible that PacifiCorp is continuing to operate the Bridger mine merely to continue collecting reclamation contributions from ratepayers, which could, and perhaps should, have been previously collected. Given these concerns, I would recommend that the Commission evaluate: 1) whether PacifiCorp's proposed reclamation costs should be considered fully fixed, and 2) whether such a large amount should be recovered from ratepayers rather than PacifiCorp's shareholders given past management practices.

Q. Other than the fixed costs identified above, is it conceivable that some of these remaining costs would be difficult to avoid if production is ramped down?

A. It would depend on the timeframe being considered. For example, it may be difficult to ramp down certain labor costs within the same year if labor agreements are already in place. However, because the TAM is forward looking, it is conceivable that PacifiCorp could make plans to reduce some of these "difficult to avoid" items in the upcoming year (i.e. 2022) before they are incurred, and certainly this could be done over multiple TAM cycles. PacifiCorp appears to agree with this concept, as they stated in response to SC 2.5: "The relationship between fixed and variable costs change depending on the time period of the review."[102]

Q. How often does PacifiCorp revisit its mining plan for BCC?

A. My understanding is that this occurs on an annual basis,[103] so it would certainly be feasible for PacifiCorp to plan for a lower production volume—and in turn incur fewer fixed costs—in the upcoming year, and in advance of its TAM filing.

[102] Sierra Club/112, Confidential PacifiCorp Response to Sierra Club Data Request 2.5(c).
[103] Sierra Club/103, PacifiCorp Response to Sierra Club Data Request 2.8.

Q. Based on these findings, what recommendations do you have for how the marginal fuel cost (dispatch tier) at Jim Bridger should be modeled in GRID for the 2022 TAM forecast?

A. Because there are no existing minimum take quantities, the marginal fuel cost in GRID should reflect a weighted average of the full cost of coal from both the Black Butte and BCC base sources. As explained in my testimony above, most of these coal costs are variable in the 2022 timeframe and as such the GRID dispatch tier should be subject to only minimal price adjustments. One possible exception to this is an adjustment to BCC base costs based on the fixed cost components described above (excluding reclamation costs for reasons described). I estimate that a [redacted] percent reduction to the BCC base costs may be warranted to account for certain fixed costs that are not avoidable. Additionally, an adjustment to the Black Butte cost may also be warranted to account for the small quantity of coal deferred from 2021. Even after accounting for these adjustments, I estimate that the dispatch tier cost of Jim Bridger for the 2022 NPC forecast should still be significantly higher than the $[redacted]/MMBtu currently being used. As I will explain in the next section, I do not think it is appropriate to base the dispatch tier price on the BBC supplemental coal price, which is what PacifiCorp has done.

B. PacifiCorp's Use of BCC Supplemental Quantity Pricing at Jim Bridger Inappropriately Skews Coal Consumption Higher and Needlessly Increases the 2022 NPC Forecast.

Q. What is the basis for PacifiCorp's assumed marginal fuel cost (dispatch tier) at the Jim Bridger plant in its 2022 NPC forecast?

A. PacifiCorp appears to have set the dispatch tier inputs equal to the BCC supplemental pricing tier, which it estimates to be $[redacted]/MMBtu.[104]

Q. Does the fact that PacifiCorp can obtain a supplemental quantity of BCC coal supply at a lower price justify the use of this price as the marginal cost for all coal delivered to Jim Bridger in 2022?

A. No. The supplemental quantity is a much smaller volume than both the BCC base quantity and the Black Butte quantity. Thus, if only the supplemental price were considered, it would misrepresent the marginal cost that PacifiCorp customers are paying for the lion's share of the coal consumed at the plant. This would be analogous to a car owner buying new a set of new tires under the familiar marketing scheme of "buy 3 tires at full price get the 4th tire for $1." It would not be logical to conclude that the marginal cost for all tires purchased in this transaction or in future transactions is $1, yet this is exactly what PacifiCorp has done when it comes to Jim Bridger coal prices in the GRID model.

Q. Does PacifiCorp assume the supplemental pricing tier for BCC is in effect even before the annual base quantity is consumed?

A. Yes. The model assumes the same dispatch tier throughout the year. The same appears to be true in actual operations too. In fact, PacifiCorp uses the supplemental pricing tier as

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[104] Bridger workpaper (Ralston).

the basis for its wholesale market sales, despite the fact that this coal fuel is ultimately paid for by its retail customers at the higher base tier prices.

Q. Do you think this practice is appropriate?

A. No. There is no possibility that PacifiCorp would have exhausted the more expensive quantities of Black Butte and BCC base fuel in the first few months of the year and therefore require the supplemental quantity, which comes at a discounted price and is only available after PacifiCorp has exhausted BCC base quantities.[105] PacifiCorp appears to be abusing the existence of a supplemental price as a means to skew marginal cost assumptions for both the forecasted and actual dispatch of Jim Bridger. Meanwhile, the full cost of BCC base and Black Butte coal, which is significantly higher than the supplemental quantity, is still charged to its retail customers.

It is also worth noting that PacifiCorp self-determines the price and quantity of its supplemental fuel from BCC through its affiliate company (Bridger Coal Company). [redacted] In a sense, PacifiCorp is acting as both the buyer and the seller in this situation and is thus able to game the supplemental pricing to its own advantage (and to the detriment of its customers).

[105] Sierra Club/105, 2021 ECAC, Tr. at 33:9-14 ("Q. In order to receive the supplemental pricing from the Bridger Mine, is it necessary for PacifiCorp to purchase all of the coal under the base mine plan first? A. Yes. That is my understanding[.]").

Q. What should PacifiCorp do instead?

A. PacifiCorp should only assume the supplemental price is in effect if it is evident that both the BCC base quantity and Black Butte quantity will be exhausted in the NPC forecast year. Additionally, for the part of the year prior to that, the marginal fuel costs should reflect the full BCC base/Black Butte prices or perhaps a weighted average, as discussed above.

Q. Is it evident that the BCC base and Black Butte quantities would be exhausted, (thereby necessitating the BCC supplemental quantity) if more appropriate pricing assumptions were used for the Jim Bridger plant?

A. No. This is readily apparent from the 2022 GRID model run that PacifiCorp conducted using the costing tier (average cost) as the marginal cost for coal fuel. In my opinion, this model run includes fuel cost inputs that are a much more reasonable approximation of the plant's true 2022 marginal costs than PacifiCorp's original 2022 NPC forecast. In this model run, the total fuel consumed at Jim Bridger in 2022 was [redacted] MMBtus.[106] In contrast, the combined quantity of fuel PacifiCorp estimates being available from the BCC base and Black Butte sources in 2022 amounts to over [redacted] MMBtus.[107] Thus, under the more accurate fuel cost assumptions in this model run, the supplemental quantity would never be needed. As such, it is not logical for the supplemental fuel to serve as the assumed marginal cost in the NPC forecast since it would never be needed under more realistic pricing assumptions.

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[106] Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 2.22 at "GRID Fuel Used (MMBtu)" (attached as Exhibit Sierra Club/123).
[107] PAC/200 at Ralston 13 (Confidential Table 1).

Q. Does PacifiCorp have an incentive to increase coal consumption at the Bridger Mine?

A. Yes. As noted in PacifiCorp's Confidential Long-Term Fuel Supply Plan for Jim Bridger Comparison Report, the price of Bridger Coal Company coal in rates includes "operating expenses plus PacifiCorp's authorized rate of return on the investment in the mine."[108]

Q. What would happen if PacifiCorp ran the GRID model with a higher dispatch tier coal price for Jim Bridger (i.e. one more reflective of the actual cost of Black Butte and BCC base coal in 2022)?

A. As demonstrated in the Average Cost run described above, this results in lower projected generation output in MWh from the Bridger plant. Under this scenario, lower-cost resources are dispatched instead of generation using BCC and Black Butte coal, and the total overall NPC would be reduced. Thus, by understating the dispatch cost, the Bridger plant is artificially run for more hours than is prudent, thereby displacing lower cost options at the expense of ratepayers while PacifiCorp is made whole through the TAM.

C. GRID Model Runs Using the Full Costing Tier for Jim Bridger (i.e., "Average Cost") Can Lead to a Lower NPC

Q. How should coal supply costs for open positions be reflected in GRID?

A. As explained in Section 4-D, there is no pre-existing minimum take provision for any open position of coal supplies that PacifiCorp anticipates will be in place for 2022 but has not yet executed. At this point in time, the Company has flexibility over the quantity to be purchased. Thus, when projecting 2022 NPC, the entire cost of these open position fuel supplies (including any potential minimum take portion) should be considered "on the

[108] Sierra Club/102, Redacted Comparison Report related to "PacifiCorp's Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant" at 4.

margin" for modeling purposes. In other words, the incremental cost is the same as the full cost (i.e. the dispatch and costing tier should be equal). Not only is this the correct modeling approach, but it will help provide insight into what quantity of coal supply is prudent before the Company commits to a new contract, including any minimums.

Q. Has PacifiCorp performed any 2022 GRID model runs using full costs that could be used to evaluate these open positions?

A. Yes. As part of the TAM 2021 settlement, PacifiCorp was required to provide a 2022 GRID model run using the costing tier (average price), mentioned above. This is provided as workpaper "zz_ORTAM22_Avg Fuel Cost Final CONF." Additionally, in response to Sierra Club's request SC 2.22 in this proceeding, PacifiCorp performed a 2022 GRID model run using the costing tier just for the Jim Bridger plant.

i. <u>2022 TAM GRID Runs Using Average Costs</u>

Q. Regarding the second GRID model run you just mentioned, can you summarize what PacifiCorp's analysis showed when it used the full costing tier for Jim Bridger in 2022?

A. Yes. The table below summarizes these results, which were provided in response to SC 2.22.

Confidential Table 10. Comparison of GRID Model Runs for 2022 Using Dispatch Tier and Costing Tier Fuel Price Assumptions for Jim Bridger

2022 TAM GRID Runs	OR 2022 TAM, Original (Dispatch Tier)[109]	OR 2022 TAM, Average (Costing Tier) for Jim Bridger[110]	Change (%)
Jim Bridger Generation (GWh, projected)	[redacted]	[redacted]	[redacted]
Jim Bridger Coal Fuel Expense ($, projected)	[redacted]	[redacted]	[redacted]
NPC	[redacted]	[redacted]	
Total Increase/(Decrease) to NPC estimated by PacifiCorp		[redacted]	

Q. What did the results of this GRID run show?

A. The table above summarizes the results, which show an overall decrease in NPC of about $[redacted]. Notably these savings occurred from modifying a single value in the model assumption—namely the cost of fuel at Jim Bridger—to ensure it is more aligned with the true marginal cost of the plant.

Q. Did this model run include any subsequent adjustments to add back in any assumed fixed fueling costs?

A. No. The only change made in this GRID run was to increase the dispatch tier price at Jim Bridger from PacifiCorp's original assumption of $[redacted]/MMBtu (which I believe is too low) to the costing tier price $[redacted]/MMBtu (which I believe is more appropriate). In this run, no "re-averaging" or other adjustments were done to account for fixed costs in the model.

[109] ORTAM22 NPC CONF (Webb) at "Coal Summary" tab.
[110] Sierra Club/123, Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 2.22.

Q. In the initial 2022 GRID model run PacifiCorp conducted using average costs (which was provided with the Company's testimony), PacifiCorp added back in certain fixed costs through a "reaveraging" step. Do you believe these adjustments were appropriate?

A. No. I don't believe there are sufficient unavoidable fixed costs within Jim Bridger's 2022 fuel supply to warrant the large adjustment that PacifiCorp included. As I explained in section 6-A regarding BCC coal, the costs projected for 2022 are largely avoidable with a few minor exceptions. Additionally, there would be no preexisting minimum take penalties at Black Butte to be avoided in 2022. While PacifiCorp deferred [redacted] tons of 2021 coal delivery from the prior contract, the plant would easily exceed this amount even under the average cost scenario and thus no penalty would be invoked.

Q. In response to SC 2.22, PacifiCorp mentioned that the absence of a reaveraging step "invalidates" the GRID model run performed for Sierra Club.[111] **Do you agree?**

A. No. In Section 6-A, I described certain fixed costs that PacifiCorp identified for BCC coal. Even if these costs were added back in, they would be insufficient to outweigh NPC savings shown in the table above. Specifically, in PacifiCorp's response to SC 2.5, the 2022 fixed costs only account for $[redacted], which is less than the projected 2022 NPC savings of $[redacted]. Additionally, I believe the $[redacted] is likely an overestimate of any presumed fixed cost adjustment. This is because a portion of $[redacted] should already be recovered from the remaining BCC coal purchases. Furthermore, as I described above, I believe the fixed costs PacifiCorp asserts in SC 2.5 may be inflated due to its treatment of reclamation and other costs.

[111] Sierra Club/103, PacifiCorp Response to Sierra Club Data Request 2.22.

Q. Do you have any observations or recommendations based on this analysis of the average cost scenario GRID model runs?

A. Yes. It appears that when the full coal fuel costs are accounted for within GRID, it can actually lead to a net reduction in NPC, however this critically depends upon PacifiCorp's assumptions for shortfall penalty payments and other presumed fixed costs at Jim Bridger. Thus, not only should the Commission ensure that PacifiCorp's NPC projections reflect the true incremental costs when there is no pre-existing shortfall penalty, but it should also make sure that other distortions are not included, such as erroneous penalty payments or inflated fixed cost assumptions.

ii. 2021 TAM GRID Runs Using Average Costs

Q. Has PacifiCorp conducted any GRID runs using Average Costs in previous TAM cycles?

A. Yes. As part of the 2021 TAM proceeding PacifiCorp provided an Average Cost GRID run in its Reply Testimony. These result of this are reproduced in SC 2.3.[112]

Q. Are there any key conclusions you would like to highlight from this 2021 TAM GRID model run using average costs?

A. Yes. The results are fairly consistent with the 2022 runs described above. Specifically, the generation at the Jim Bridger plant, and overall coal fuel costs, were both significantly lower under the Average Cost scenario. Nevertheless, PacifiCorp claimed that this scenario would increase NPC costs by $[redacted].[113]

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[112] Sierra Club/121, Confidential Attach. 2.3.
[113] UE 375, Reply Testimony of David G. Webb on Behalf of PacifiCorp (PAC/500) at Webb/38:9 (June 2020).

Q. Do you have any concerns about this finding?

A. Yes. It appears that PacifiCorp assumed that coal consumption at Jim Bridger would ramp down primarily from the Black Butte supply (rather than the BCC supply) thereby triggering over $[redacted] in penalty payments due to the minimum take in effect for Black Butte in 2021.[114]

Q. How would the results have differed if PacifiCorp had assumed that the reductions in coal consumption came from BCC rather than Black Butte, thus avoiding the penalty?

A. The results would have been very different. If the BCC coal were reduced first, there is no chance that the penalties for the Black Butte supply would have been triggered. With these spurious costs removed, then I estimate that the average cost scenario could have yielded up to a $[redacted] *reduction* in total NPC costs rather than the $[redacted] increase that PacifiCorp asserted.

Q. What do these 2021 results illustrate to you regarding PacifiCorp's general approach to NPC modeling of coal plants?

A. While not directly relevant to the 2022 TAM, the 2021 GRID runs underscore the fact that PacifiCorp has a demonstrated pattern of applying significant and questionable post-modeling adjustments to its GRID results—often with little explanation or transparency.

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[114] Sierra Club/121, Confidential Attach. 2.3.

D. Unit Commitment and Dispatch Decisions for Jim Bridger Rely on Inaccurate Marginal Costs Inputs for BCC Coal

Q. If PacifiCorp followed your recommendations and corrected the GRID inputs assumptions for Jim Bridger, would that lead to an actual reduction in generation at the plant in 2022?

A. Not necessarily. The GRID runs conducted in this proceeding provide a forecast of generation, but this does not necessarily mean that PacifiCorp will make similar changes in its unit commitment and dispatch practices.

Q. How has PacifiCorp historically made unit commitment & dispatch decisions for Jim Bridger?

A. Until it was retired in October 2020, the iOpt model was used to create a starting point for PacifiCorp's energy traders when determining unit commitment and dispatch decisions. Since that time, PacifiCorp has used the Power Costs Incorporated ("PCI") for the same purpose. According to PacifiCorp, "market traders use the modeled results as a guide when making decisions on dispatching Company assets."[115] While it was in use, iOpt functioned by creating a five-day hourly generation profile for the entire PacifiCorp power system, including energy prices at transmission trading hubs and fuel prices for each generation unit. The iOpt model seeks out the least-cost dispatch scenario by ordering plants according to their increasing marginal costs.[116] Similarly, the PCI optimization model determines "the best possible unit dispatch schedule to most economically satisfy all system obligations for the next business day."[117] While the

[115] A.20-08-002, PacifiCorp Response to Sierra Club Data Request 3.1(b) (attached as Exhibit Sierra Club/124).
[116] A.20-08-002, PacifiCorp Response to Sierra Club Data Request 5.1(b) (attached as Exhibit Sierra Club/125).
[117] Sierra Club/103, PacifiCorp Response to Sierra Club Data Request 1.19(a).

iOpt/PCI outputs serve as a starting point, PacifiCorp's energy traders may then make different decisions during actual operations due to changes in system conditions since the completion of the model run.

Q. What fuel price do PacifiCorp's energy traders assume for Jim Bridger when optimizing its system?

A. According to PacifiCorp, "the fuel cost used for the Jim Bridger units was the plants' incremental cost from the Bridger Coal Company coal mine supplemental coal supply agreement."[118] Thus, the energy traders assume that the lower cost BCC supplemental pricing tier is always in effect at Jim Bridger, rather than the higher cost BCC coal. Some recent examples of this are provided in Confidential Attachments to SC 1.32, which show Jim Bridger fuel costs ranging from $[redacted]/MMBtu.[119]

Q. How does this compare to the actual cost of coal from the BCC base quantity?

A. It is substantially lower. As described above in Section 4(C), the full cost of BCC base coal is closer to ~[redacted]/MMBtu.

Q. Is it appropriate to assume BCC supplemental pricing for all coal fuel consumed at Jim Bridger?

A. No. As explained in section 6-B, PacifiCorp would only need to purchase supplemental coal if and when the base quantity for BCC was consumed and the minimum take for Black Butte had been satisfied. For example, it would be inappropriate to use this

[118] A.20-08-002, PacifiCorp Response to Sierra Club Data Request 7.1(b) (attached as Exhibit Sierra Club/126).
[119] Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.32 (excerpt attached as Exhibit Sierra Club/127).

supplemental price assumption at the beginning of the year since neither of these requirements would have been met, yet PacifiCorp has done so.

Q. What does the discrepancy between the base quantity price for BCC coal and iOpt assumptions (i.e. supplemental pricing) ultimately mean in terms of costs to ratepayers?

A. This means that PacifiCorp's energy traders assumed a lower marginal fuel cost than was correct for much of the fuel consumed when making dispatch decisions for Jim Bridger. In turn, the plant undoubtedly operated more frequently, while retail customers still pay the differential between the iOpt/PCI modeled cost and the true cost of the base quantity BCC coal. In essence, PacifiCorp's unit commitment and dispatch practices assumed that a substantial ratepayer-funded subsidy should be applied to a significant portion of the coal fuel costs at Jim Bridger. I do not believe such a subsidy is appropriate or has been authorized by this Commission.

Q. Have you conducted any analysis to estimate how much this ratepayer subsidy would amount to based on the known consumption of coal at Jim Bridger in recent years?

A. Yes. As part of the California 2021 ECAC proceeding, which is analogous to the TAM, I analyzed PacifiCorp's iOpt forecasts and actual dispatch at Jim Bridger over the relevant true up period (January 2019 through May 2020). Based on this analysis, I determined that the unauthorized subsidy for BCC coal was on the order of tens of millions of dollars that is being charged to ratepayers today.

Q. At that higher level of fuel cost, reflecting BCC's actual costs, would there have been times when Jim Bridger was operating uneconomically?

A. Yes. In fact, based on my ECAC analysis for 2019 and 2020 this would have been quite common. When compared to the Palo Verde market hub price that PacifiCorp estimated in iOpt there were many hours when the cost of Jim Bridger using BCC coal as the marginal fuel source would have resulted in costs higher than the market prices (i.e. it was "out of the money"). If the iOpt dispatch had been followed, I estimated that the plant would have been operating uneconomically more than half of the time.[120]

Q. What conclusions and recommendations do you have based on this analysis?

A. In addition to correctly forecasting the most economic operations of the Jim Bridger in GRID for the 2022 TAM, it is also critically important that the Commission track and evaluate how PacifiCorp actually operates the plant in 2022. If PacifiCorp's energy traders continue to incorrectly assume the BCC supplemental price is always in effect when generating forecasts for unit commitment and dispatch, then it is likely that overgeneration will still occur, despite what the 2022 forecast indicates. Thus, I recommend that the Commission require PacifiCorp provide a transparent accounting of how plant specific fuel cost assumptions used by its energy traders correspond to those used in the TAM forecast. I suggest that this reporting be provided in both the TAM and PCAM proceedings going forward. Additionally, in reviewing the present 2020 PCAM

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[120] A.20-08-002, Direct Testimony of Ed Burgess on Behalf of Sierra Club (SC-01) at 42:16-22 (Mar. 18, 2021).

adjustment (and when PacifiCorp applies for its 2021 and 2022 PCAM), I recommend that the Commission seek to identify any mismatches between the incremental costs assumed for dispatch, and the costs recovered through retail rates. Any discrepancies should be considered in determining if there was an over-recovery of prudent costs, or if an under-recovery might have been reduced.

7. Summary of Recommendations

Q. Can you provide a summary of your recommendations?

A. Yes. My recommendations are as follows:

1. The Commission should direct PacifiCorp to revise the NPC component of the proposed 2022 TAM to account for inappropriate coal fuel costs forecasted for Bridger Coal Company coal which arise from incorrect assumptions about the marginal cost in GRID and lack of consideration for the flexibility of this fuel source.
2. Going forward, the Commission should ensure that PacifiCorp's NPC projections reflect the true incremental costs of fuel, especially when there is no pre-existing shortfall penalty or approved contract, and that other distortions (e.g. erroneous penalty payments, avoidable fixed costs, etc.) are not included in the projection model. This should also be standard practices for any new coal contract negotiations.
3. The Commission should only approve 2022 TAM rates on an interim basis for any projected costs associated with PacifiCorp's open position fuel supplies at Jim Bridger (Black Butte), Naughton (Kemmerer), and Dave Johnston (Unspecified PRB). These rates should be updated once the Commission has had a chance to review the specific contract details, which PacifiCorp should provide as a supplemental filing including additional GRID model runs. Reasonable assumptions

about these contracts can be used now for GRID modeling purposes, to estimate the remainder of 2022 TAM costs.

4. Similarly, the Commission should defer final approval of any fixed costs for BCC coal included in the 2022 TAM until the Commission has had an opportunity to review what actual costs were incurred, and whether these were prudent.
5. The Commission should require PacifiCorp to provide a tracking report detailing PacifiCorp's daily unit commitment and dispatch decisions for each of its thermal plants over the course of 2022. This report should include details on: 1) marginal fuel costs assumed by PacifiCorp's energy traders, 2) expected operating costs, 3) expected market price, 4) whether the plant was operated as "must run" or economically committed, and 5) what the assumed cycling costs were.
6. As a requirement of future TAM filings, the Commission should require PacifiCorp to include a report on the steps it has taken to reduce ratepayer costs associated with the BCC mine and replace this generation with lower cost sources.
7. The Commission should deem the new Hunter CSA minimum take quantities to be imprudent. As a remedy, any future minimum take penalties that arise from the Hunter CSAs should not be recovered from PacifiCorp customers.
8. The Commission should establish best practices for future coal contracting decisions, including reducing the minimum take requirement in coal supply agreements, minimizing the length of future contracts, including provisions that allow for avoidance of minimum take requirements, and forecasting anticipated generation using average costs in anticipation of coal contract negotiations.

9. The Commission should require PacifiCorp to provide copies of its coal supply agreements and affiliate mine plans as a standard part of future TAM applications. The process of providing these documents should abide by any and all necessary protective orders to ensure any competitively confidential information is protected.
10. I recommend that the Commission conduct a comparison of each cost recovery mechanisms to ensure that there are no duplicative depreciation costs for the BCC mine being recovered in both base rates and the TAM.

Q. Does this conclude your testimony?

A. Yes.

PUBLIC UTILITY COMMISSION OF OREGON

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EXHIBIT SIERRA CLUB/101

Exhibit Accompanying the Opening Testimony of Ed Burgess

Curriculum Vitae of Ed Burgess

Edward Burgess

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Overview

Ed Burgess is Senior Director of Strategen Consulting's Government and Utility Consulting Practice. His core expertise is in policy and regulation of the electric power sector at the state level, with a specialized focus on economic analysis, technical regulatory support, resource planning and procurement, utility rates, and policy & program design. Ed has served clients in the renewable energy, energy storage, electric vehicle, and energy efficiency industries, including several private companies, energy project developers, trade associations, utilities, government agencies, and foundations. His technical analysis has helped to shape state regulations and policies related to energy portfolio standards, distributed energy resources, rate design, resource planning and transmission/distribution system planning. Prior to joining Strategen, Ed played a lead role in two major initiatives at Arizona State University: The Utility of the Future Center and the Energy Policy Innovation Council where he conducted research and policy analysis for the Governor's Office of Energy Policy, the Department of Environmental Quality, and other major stakeholders in Arizona. Ed also worked as an independent consultant for Schlegel & Associates, providing technical analysis on demand-side management policies, and for Kris Mayes Law Firm providing regulatory support to the solar industry in the Southwest U.S.

Senior Director
AUG 2019 – Present

Director
JAN 2018 – AUG 2019

Senior Manager
JUL 2016 – DEC 2017

Manager
JUL 2015 – JUN 2016
Strategen Consulting – Berkeley, CA

Independent Consultant
NOV 2012 – JUL 2015
Schlegel & Associates – Phoenix, AZ
JUN 2012 – JUL 2015
Kris Mayes Law Firm – Phoenix, AZ

Project Manager & Researcher
JUN 2012 – JUL 2015
Arizona State University – Tempe, AZ

Instructor
JUN 2011 – MAY 2012
Arizona State University School of Sustainability – Tempe, AZ

Research Fellow
JUL 2007 – JUL 2009
Environmental Defense Fund – New York, NY

EDUCATION

PSM, Solar Energy Engineering and Commercialization
Arizona State University, 2012

MS, Sustainability
Arizona State University, 2011

BA, Chemistry
Princeton University, 2007

EXPERIENCE – 11 YEARS

Energy Resource Planning & Procurement

Utility Rates and Regulation

Cost Benefit Analysis

Avoided Cost and Cost Effectiveness

Energy Policy & Markets

Energy Product Development & Market Strategy

Stakeholder Engagement

Management Consulting

Selection of Relevant Projects at Strategen Consulting

Massachusetts Attorney General's Office

- Appeared as an expert witness and supported drafting of testimony on the implementation of the MA SMART program (D.P.U. 17-140), which is expected to deploy 1600 MW of solar PV (and PV + storage) resources over the next several years.
- Served as an expert consultant on multiple rate cases regarding utility rate design and implications for ratepayers and distributed energy resource deployment.

New Hampshire Office of the Consumer Advocate

- Worked with the state's consumer advocate to develop expert testimony on a case reforming the state's market for distributed energy resources.
- Developed a new methodology for designing retail electricity rates that is intended to support greater deployment of energy storage.

District of Columbia, Office of the People's Counsel

- Provided technical support and analysis on a utility proposed electric vehicle charging program
- Supported drafting comments on the Counsel's position in favor of a more customer-friendly approach to electric vehicle program implementation

North Carolina, Office of the Attorney General

- Provided technical support and analysis to the state's consumer advocate on utility integrated resource plans and their implications for customers and public policy goals.

Maryland, Office of People's Counsel

- Provided technical support to the state's consumer advocate topics associated with the large PC44 grid modernization effort.
- Topics included electric vehicles, energy storage, distribution grid planning, and interconnection.

Arizona, Residential Utility Consumer Office (RUCO)

- Supported drafting of expert witness testimony on multiple rate cases regarding utility rate design, distributed solar PV, and energy efficiency.
- Performed analytical assessments to advance consumer-oriented policy including rate design, resource procurement/planning, and distributed generation consumer protection.
- Lead author on the white paper published by RUCO introducing the concept of a Clean Peak Standard.

Portland General Electric

- Provided education and strategic guidance to a major investor-owned utility on the potential role of energy storage in their planning process in response to state legislation (HB 2193).
- Participated in public workshop before the Oregon Public Utilities Commission on behalf of PGE.
- Supported development of a competitive solicitation process for potential storage technology solution providers.

Xcel Energy

- Conducted analysis supporting the design of a new residential time-of-use rate for Northern States Power (Xcel Energy) in Minnesota.

City and County of San Francisco

- Aided in evaluation of solar PV with battery storage as a solution for resilience of critical infrastructure.
- Provided technical economic assessment of opportunities for wholesale market participation as an added value for facilities installed.

University of California, San Diego

- Conducted economic analysis to help guide a multi-year research project on the use of advanced solar forecasting technology to improve integrated solar and energy storage.

University of Minnesota

- Facilitated multiple stakeholder workshops to understand and advance the appropriate role of energy storage as part of Minnesota's energy resource portfolio.

- Conducted study on the use of storage as an alternative to natural gas peaker.
- Presented workshop and study findings before the Minnesota Public Utilities Commission.

Arizona State University (ASU)/Arizona Department of Environmental Quality (ADEQ)

- Project manager for partnership between ASU/ADEQ to study compliance options for the state of Arizona to meet requirements of the EPA's Clean Power Plan (CPP).
- Completed a comprehensive study on the impact of CPP scenarios on the operation of the southwest power grid and cost to Arizona and Navajo Nation electricity customers.

Recent Publications

Edward Burgess, Ellen Zuckerman, and Jeff Schlegel, "Is the Duck Curve Eroding the Value of Energy Efficiency" Proceedings of the American Council for an Energy Efficiency Economy (ACEEE) 2018 Summer Study on Energy Efficiency in Buildings, (pending).

Lon Huber, Ed Burgess, "Evolving the RPS: A Clean Peak Standard for a Smarter Renewable Future," (November 2016), Arizona Residential Utility Consumer Office, Arizona Corporation Commission, Docket No. E-00000Q-16-0289, https://www.strategen.com/s/Evolving-the-RPS-Whitepaper.pdf

Mark Higgins, Ed Burgess, and Bill Ehrlich, "Energy Storage Likely to Increase in Utility Resource Planning" Natural Gas and Electricity, Volume 32, Number 10 (May 2016).

Ellen Zuckerman, Edward Burgess, and Jeff Schlegel, "Are Recent Forays into Restructuring a Threat to Energy Efficiency?" Proceedings of the American Council for an Energy Efficiency Economy (ACEEE) 2014 Summer Study on Energy Efficiency in Buildings, (August 2014) http://aceee.org/files/proceedings/2014/data/papers/6-1135.pdf#page=1.

Sonia Aggarwal and Edward Burgess, "Performance Based Models to Address Regulatory Challenges" The Electricity Journal (July 2014) http://www.sciencedirect.com/science/article/pii/S1040619014001389.

"Transmission and Renewable Energy Planning in California," prepared for the Western Governors Association, (November 2012) http://www.westgov.org/wieb/wrez/11-28-2012WREZca.pdf.

Edward Burgess and Petra Todorovich, "High-Speed Rail and Reducing Oil Dependence" in Transport Beyond Oil, Island Press (March 2013).

"On the nature of the dirty ice at the bottom of the GISP2 ice core," Earth & Planetary Science Letters (October 2010). http://www.sciencedirect.com/science/article/pii/S0012821X10006084

Selected Speaking Engagements

- California Energy Storage Alliance, Market Development Forum (February 2019)
- Rutgers University, Rutgers Energy Institute 2018 Annual Symposium (May 2018)
- Energy Storage North America (August 2017)
- MN Energy Storage Workshop (Sept 2016 & Jan 2017);
- Arizona Corporation Commission Peak Demand Workshop, (August 2016);
- Arizona Department of Environmental Quality, Clean Power Plan Technical Working Group, (May 2016);
- Energy Storage North America (2015);
- ASU Clean Power Workshop (February 2015);
- Western Interstate Energy Board Meeting (March 2014).

Docket No. UE 390
Exhibit Sierra Club/102
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

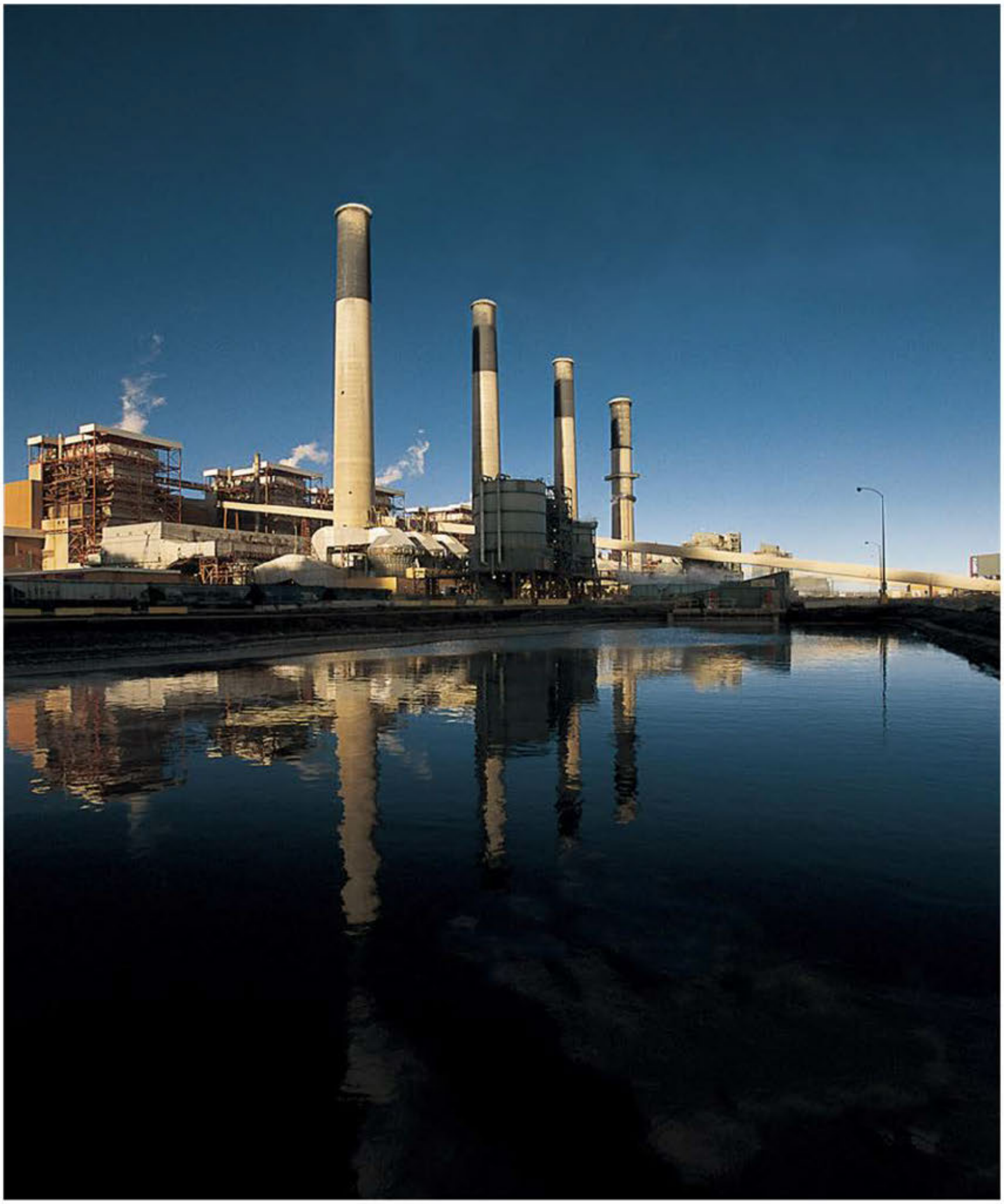
EXHIBIT SIERRA CLUB/102

Exhibit Accompanying the Opening Testimony of Ed Burgess

Redacted PacifiCorp Long-Term Fuel Supply Plan for the Jim Bridger Plant Comparison Report

PACIFICORP

PACIFICORP's CONFIDENTIAL LONG-TERM FUEL SUPPLY PLAN FOR THE JIM BRIDGER PLANT



Contents

Introduction

In Public Utility Commission of Oregon (Oregon Commission) Order No. 13-387 in docket UE 264, the Oregon Commission adopted the proposal of PacifiCorp dba Pacific Power (PacifiCorp or Company) to prepare periodic fuel supply plans comparing affiliate mine supply to alternative fuel supply options, including market alternatives.[1] In docket UE 287, PacifiCorp filed a compliance proposal for future periodic fuel supply plan filings.[2] No party objected to the proposal, and the case was resolved through Commission approval of stipulation resolving all issues.[3]

As set forth in the Company's docket UE 287 compliance filing, the purpose of long-term fuel supply plans for plants fueled from captive mines is to determine the least-cost, least risk coal supply, viewed on a multi-year basis. The long-term fuel supply plan is designed to ensure that fuel supplies are fair, just and reasonable, and that they satisfy the Oregon Commission's prudence and affiliate interest standards.

To develop this long-term fuel supply plan for the Jim Bridger plant, the Company has reviewed the fueling options for the plant, reviewed Bridger Coal Company mine plans, reviewed data on market costs for alternative supplies, including transportation costs and costs for plant modifications required to support alternative supplies, and compared the different fuel supply options under different scenarios to determine the least-cost, least-risk approach.

Background

The Jim Bridger plant is a four unit coal-fired plant in Sweetwater County, Wyoming. The facility is located approximately eight miles north of Point of Rocks, Wyoming, and approximately 24 miles east of the city of Rock Springs, Wyoming. The Union Pacific railroad provides rail access to the plant.

The Jim Bridger plant is the largest plant on the PacifiCorp system (2,120 megawatts) and is jointly owned by PacifiCorp (66.7 percent) and Idaho Power Company (Idaho Power) (33.3 percent). The depreciable life of PacifiCorp's share of the Jim Bridger plant extends through 2025 in Oregon and through 2037 in all other states, based on PacifiCorp's 2012 depreciation study. The Jim Bridger plant consists of four almost identical units, each with a nominal 530 net megawatt capacity. The Jim Bridger plant typically consumes 7.5 million to 8.5 million tons of coal per year, and is designed to burn local southwest Wyoming coal with heat content in the range of 9,000 Btu/lb to 10,000 Btu/lb.

Bridger Coal Company is located adjacent to the Jim Bridger plant. Bridger Coal Company includes both surface and underground mining operations and, similar to the Jim Bridger plant, is jointly owned by PacifiCorp (66.7 percent) and Idaho Power (33.3 percent). The surface operation consists of a combination dragline and truck/loader operation that produces approximately 2.0 to 2.5 million tons of coal per year. The underground operation uses continuous miner and longwall mining equipment to produce coal. The coal is transported from the underground operation to the surface

1 *In the Matter of PacifiCorp, dba Pacific Power, 2014 Transition Adjustment Mechanism,* Docket UE 264, Order No. 13-387 at 7 (Oct. 28, 2013).
2 *In the Matter of PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism,* Docket UE 287, Direct Testimony of Cindy Crane, Exhibit PAC/201 (April 2014).
3 *In the Matter of PacifiCorp, dba Pacific Power, 2015 Transition Adjustment Mechanism,* Docket UE 287, Order No. 14-331 (Oct. 1, 2014).

stockpile or directly to the Jim Bridger plant via a nine mile overland conveyor belt. The underground mine produces approximately 3.5 to 4.0 million tons of coal per year.

In addition to the estimated 5.5 to 6.0 million tons of coal delivered annually from Bridger Coal Company to the Jim Bridger plant, the Jim Bridger plant has historically received the remaining portion of its coal supply requirements, approximately 2.0 to 2.5 million tons per year, from the nearby Black Butte mine, which is located approximately 20 miles from the Jim Bridger plant.

For regulatory purposes, Bridger Coal Company is consolidated with PacifiCorp's regulated operations, including the Jim Bridger plant.[4] PacifiCorp's share of Bridger Coal Company is included in the Company's rate base and its share of mining costs, including depreciation and depletion, is included in net power costs. This is a cost-based approach, limiting the price of Bridger Coal Company coal in rates to operating expenses, plus PacifiCorp's authorized rate of return on the investment in the mine.[5]

4 *In re Pacific Power & Light Co*., Docket UE 21, Order No. 84-898 (Nov. 14, 1984).
5 *In re Pacific Power & Light Co*., Docket UF 3779, Order No. 82-606 (Aug. 18, 1982).

Available Fuel Supply Alternatives

Based on the location of the Jim Bridger plant, economic fuel supply alternatives are limited to the mines located in southwest Wyoming and the Powder River Basin mines of Campbell County, Wyoming.

In addition to Bridger Coal Company, there are three other coal mines in southwest Wyoming: Kemmerer, Haystack and Black Butte. Two of these mines, the Kemmerer and Haystack mines, are not viable fuel sources for the Jim Bridger plant. The Kemmerer mine currently supplies PacifiCorp's Naughton plant and southwest Wyoming's trona (soda ash) industry. The Kemmerer mine is an older operation, PacifiCorp having first purchased coal from the Kemmerer mine under a Coal Purchase Agreement dated December 30, 1957. The Kemmerer mine coal is delivered to customers via overland conveyor, truck transportation and limited rail operations. Presently, the Kemmerer mine's rail loading infrastructure is incapable of loading a full unit train efficiently. In addition, the grade elevation surrounding the mine requires additional locomotives to power a full unit train. As a result, the mine rarely loads full unit trains. Given the Kemmerer mine's current rail loading infrastructure, any sizable volume of Kemmerer coal would require truck transportation to the Jim Bridger plant. The mine's production costs, required truck transportation for a distance of approximately 120 miles, and the lack of significant excess capacity, result in the Kemmerer mine not being a viable fuel source on a delivered costs basis for the Jim Bridger plant.

The Haystack mine, located 30 miles south of PacifiCorp's Naughton plant, is owned by Kiewit Mining. Designed to operate as a small surface truck/loader operation, Kiewit Mining began construction of the mine in 2012. Due to a lack of demand for coal, Kiewit Mining made a decision to idle this mine in April 2013. All coal sold from the Haystack mine will be delivered with truck transportation. Similar to the Kemmerer mine, the Haystack mine's location, lack of transportation infrastructure, and limited capacity negate its viability as a fuel source on a delivered cost basis for the Jim Bridger plant.

In addition to Bridger Coal Company, this leaves two possible coal supply alternatives for the Jim Bridger plant. These alternatives are the Black Butte mine and the Powder River Basin mines of Campbell County, Wyoming.

The Black Butte mine, located 20 miles southeast of the Jim Bridger plant, is jointly owned by Lighthouse Resources and Anadarko Petroleum. Operated by Lighthouse Resources, the mine is a multiple seam, multiple pit operation with the overburden removed by draglines and a truck and shovel fleet. Historically, Black Butte has mined approximately 3.5 million to 4.0 million tons per year, a significant portion of which has supplied the Jim Bridger plant. One of the Black Butte mine's significant contracts will expire December 31, 2015. Starting in 2016, the mine is expected to produce between [redacted]. Currently, the Jim Bridger plant receives approximately 25 percent of its fuel supplies from the Black Butte mine, under a contract that began earlier this year and terminates in 2017. Coal from the Black Butte mine is delivered to the plant under an agreement with the Union Pacific Railroad.

The Powder River Basin of Wyoming and Montana is the largest coal mining region in the United States. Coal from the Powder River Basin is classified as sub-bituminous coal. Wyoming Powder River Basin coal contains average heat content of approximately 8,500 Btu/lb. The majority of the coal mined in the Wyoming Powder River Basin is low sulfur and low ash coal, making coal from the Wyoming Powder River Basin very desirable. Due to its unique quality characteristics, in 2014

Wyoming Powder River Basin coal was consumed by energy markets in 30 states across the country. In 2014, there were seven different mining companies operating eleven active mines in the region, producing more than 345 million tons.

Powder River Basin mines are served by two railroads, the Union Pacific and Burlington Northern Santa Fe. Both of these railroads have joint access to all of the mines located in the Powder River Basin which are south of Gillette, Wyoming. Only the Burlington Northern Santa Fe Railway serves the mines located north of Gillette, Wyoming.

The Powder River Basin mines that would be considered to supply coal to the Jim Bridger plant are those located in the southern portion of the Powder River Basin. Mines located in this region contain the highest heat content ranging between 8,600 Btu/lb. and 9,000 Btu/lb. These mines are located approximately 550 to 600 miles from the Jim Bridger plant.

Alternative Fuel Supply Plans Evaluated

Considering the limited coal supply alternatives available to the Jim Bridger plant, the Company evaluated two fuel supply alternatives only, the Base Operating Plan and the Market Alternative Plan. Both plans assume decreasing reliance on fuel supply from the Bridger Coal Company and from the Black Butte mine and increasing reliance on fuel supply from the Powder River Basin; the plans differ in whether the Company continues to source fuel from the Bridger Coal Company surface mine or moves entirely to a market-based supply. Because this is a long-term planning document, the Company's evaluation of alternative fuel supply plans was conducted on a total company basis, utilizing the longest depreciable life now recognized in PacifiCorp's jurisdictions, 2037.

Base Operating Plan

Historically, the Jim Bridger plant has consumed about 7.5 million to 8.5 million tons of coal on an annual basis. Approximately two-thirds of the coal has been sourced from Bridger Coal Company while the remainder, approximately one-third, has been purchased from the Black Butte mine. [redacted]

As the largest plant in PacifiCorp's portfolio, on average the Jim Bridger plant consumes the equivalent of roughly 1 1/2 unit trains of coal daily. The Jim Bridger plant's existing unloading facilities consist of three ladder tracks and an unloading hopper designed to unload rapid discharge railcars with a payload of up to 118 tons per railcar. The existing design necessitates that trains longer than 72 railcars be broken into sections for unloading which significantly increases train unloading time. The current plant infrastructure does not include additional sidings to allow for the staging of large unit trains. This configuration essentially limits the plant's ability to place more than one Powder River Basin unit train in service at any one time. Given the Jim Bridger plant's existing rail unloading facility constraints, the Jim Bridger plant's capacity for unloading Powder River Basin coal trains is estimated at [redacted] tons per year at a rate of approximately one train every [redacted] days.

A major plant capital investment will be required to accommodate the [redacted]. The capital investment is required primarily to upgrade the Jim Bridger plant's rail unloading capabilities. The cost of this conversion is estimated at [redacted] (PacifiCorp share)[6] and would include a rail loop track and other major expenditures to accommodate the unloading of more than 300 trains per year. With the addition of the rail unloading infrastructure, [redacted] Key components of the Base Operating Plan are summarized below:

- Base Operating Plan
  [redacted]

Market Alternative Plan

Similar to the Base Operating Plan, the Market Alternative Plan assumes the same major capital expenditures to upgrade the Jim Bridger plant's rail unloading facility. As this expenditure is sufficient to accommodate unloading 100 percent of the Jim Bridger plant's requirements, the Market Alternative Plan contemplates [redacted]. Key components of the Market Alternative Plan are summarized below:

- Market Alternative Plan
  [redacted]

6 The capital investments and present value revenue requirement costs referenced in this plan are stated on a total company basis.

[redacted]

The Base Operating Plan assumptions were derived from PacifiCorp's 2015 Integrated Resource Plan (IRP), submitted March 31, 2015. For comparison purposes, the key assumptions used in preparation of the IRP, including coal consumption (MMBtus), were also used in the preparation of the Market Alternative Plan.

The volume assumptions used in the two plans are provided in Confidential Table 1 below:

Confidential Table 1

[redacted]

The key pricing assumptions used in the two plans are summarized in Confidential Table 2 below:

Confidential Table 2

[redacted]

[redacted]

Results

Confidential Table 3 below compares the Present Value Revenue Requirement (PVRR) for the two fueling options. The Company estimates that the Base Operating Plan is [redacted] less costly than the Market Alternative Plan.

Confidential Table 3

[redacted]

[redacted]

Conclusion

PacifiCorp has evaluated the Base Operating Plan and Market Alternative Plan for the Jim Bridger plant. The PVRR analysis of the Base Operating Plan for the Jim Bridger plant yields a PVRR of [redacted]. The PVRR analysis of the Market Alternative Plan yields a result of [redacted]. The evaluation demonstrates that the Base Operating Plan is [redacted] favorable to the Market Alternative Plan fuel plan. As a part of its regular planning process, PacifiCorp will continue to evaluate all available options for the long-term fueling of the Jim Bridger plant.

Docket No. UE 390
Exhibit Sierra Club/103
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

EXHIBIT SIERRA CLUB/103

Exhibit Accompanying the Opening Testimony of Ed Burgess

Selected Public PacifiCorp Data Responses

Exhibit Sierra Club/103

Selected PacifiCorp Public Responses to Sierra Club Data Requests

1. PacifiCorp Response to Sierra Club Data Request 1.19
2 PacifiCorp Response to Sierra Club Data Request 1.22
3 PacifiCorp Response to Sierra Club Data Request 1.28
4. PacifiCorp Response to Sierra Club Data Request 2.8
5. PacifiCorp Response to Sierra Club Data Request 2.19
6 PacifiCorp Response to Sierra Club Data Request 2.22

UE 390 / PacifiCorp
May 7, 2021
Sierra Club Data Request 1.19

Sierra Club Data Request 1.19

Regarding the Company's unit commitment decision process for its coal-fuel units:

(a) Describe the Company's process for determining whether to dispatch a coal unit.

(b) Describe the Company's process for determining whether to commit its coal units for export to the CAISO day ahead energy market.

(c) Describe the Company's process for determining whether to commit its coal units to the Western EIM.

(d) Describe the Company's process for determining whether to self-schedule its coal units at generating levels above their minimum operation levels.

(e) Describe how the Company coordinates with co-owners to make decisions regarding whether and how to commit and operate jointly owned coal units on an hourly basis.

(f) Does the Company perform economic analyses to inform its unit commitment decisions (i.e., decisions regarding whether to designate its coal units as must run or take them offline for economic reasons)?

(g) Please describe how each of the above is reflected in the Company's GRID modeling.

Response to Sierra Club Data Request 1.19

(a) The Company uses the Power Costs Incorporated (PCI) optimization model to determine the best possible unit dispatch schedule to most economically satisfy all system obligations for the next business day. The PCI optimization model takes into account all the available generators unit characteristics (Pmax, Pmin, ramp rate, fuel costs, start-up costs, etc.), system obligations (system load, bilateral transactions, reserve requirements, etc.) and transmission limits in order to economically meet the Company's obligations. The cash traders (traders responsible for the day-ahead set up) make the final decision to dispatch the coal-fueled units based on meeting system obligations and minimizing net power costs (NPC).

(b) Using the PCI optimization model described in subpart (a) above, the Company would not specifically dispatch a coal unit with a sole purpose of exporting to the California Independent System Operator (CAISO) day-ahead market. If the optimal PCI solution yielded additional marketable capacity, the day-ahead traders would weigh all market opportunities including the CAISO day-ahead energy market in order to economically optimize the committed generators. PacifiCorp does not export or import specific generators in the CAISO day-ahead market.

(c) PacifiCorp's coal units are not committed for the purposes of transacting in the Western energy imbalance market (EIM). Please refer to the Company's response to subpart (a) above for information regarding unit dispatch decisions.

(d) The Company assumes that Sierra Club's use of the term "self-schedule" is intended to reference the CAISO defined term "Self-Schedule" as it applies to the Western EIM. Based on the foregoing assumption, the Company responds as follows:

PacifiCorp does not self-schedule its coal units at generating levels above their minimum operation levels.

(e) PacifiCorp works with the co-owners, utilizing telephone conversations, day-ahead scheduling information, EIM base schedules and the automated dispatch system for all operating decisions for its joint-owned coal resources, including commitment decisions and operational levels.

(f) Please refer to the Company's response to subpart (a) above.

(g) For economic modeling purposes, the Generation and Regulation Initiative Decision Tool (GRID) looks at all the generating resources together in its optimization analysis. The optimization process uses forecasted hourly inputs including system load, coal and gas unit operating limitations (heat rate, fuel price, up-times / down-times, outages, etc.), hydro and wind generation, contractual positions, market prices and firm transmission constraints. All optional modeling elements including coal unit dispatch are optimized simultaneously within the established constraints of the inputs.

UE 390 / PacifiCorp
May 7, 2021
Sierra Club Data Request 1.22

Sierra Club Data Request 1.22

Please describe whether and how the model and inputs used to determine the annual generation requirements for coal contract negotiation differs from the GRID model and inputs used to calculate NPC.

Response to Sierra Club Data Request 1.22

PacifiCorp continually refines its process for development of generation forecasts used to support coal contract negotiations. Each new coal supply agreement (CSA) presents unique facts and circumstances. The current process uses the business plan generation forecasts as a starting point, and then additional Generation and Regulation Initiative Decision Tool (GRID) runs are performed as needed. Multiple PacifiCorp departments are involved in the generation forecast process including representatives from the fuel resources department, the energy supply management (ESM) department, the resources and commercial strategy department and the ESM finance department.

The business plan GRID forecast is run for a different purpose and at a different time of year than GRID runs for ratemaking. The purpose of the business plan GRID run is to try to capture recent market trends and volatility that could impact the forecast year whereas the ratemaking GRID runs try to capture more normalized results. The GRID model used for budgetary purposes and regulatory purposes is the same, however, the underlying database is different.

Because of the unique facts, timing and circumstances surrounding each coal supply negotiation and a continual refinement of the generation forecasts over time a lasting and consistent difference between these forecasts and ratemaking GRID forecasts cannot be delineated. For example, for all inputs that are updated on at least annually would be potentially different between two forecasts if they were prepared over one year apart but they would be the same if the two forecasts were prepared at the same time.

UE 390 / PacifiCorp
May 7, 2021
Sierra Club Data Request 1.28

Sierra Club Data Request 1.28

Identify all currently effective coal supply contracts that include a provision that allows PacifiCorp to reduce any minimum purchase obligation for coal based on actual or prospective environmental legislation or regulation impacting coal-burning generation.

(a) For each such identified provision, identify the minimum purchase obligation that would result if PacifiCorp elected to use or rely on such provision.

(b) For any currently effective coal supply contract, has PacifiCorp elected to use or rely on a provision that allows PacifiCorp to reduce the minimum purchase obligation for coal based on actual or prospective environmental legislation or regulation impacting coal-burning generation? If yes, identify the specific contract and date of such election.

(c) Please provide any and all analysis conducted on relying on such a provision in each of PacifiCorp's coal supply contracts. If no such analysis has been conducted, please explain why.

Confidential Response to Sierra Club Data Request 1.28

The currently effective coal supply agreements (CSA) are listed below:

I. Naughton Plant CSA– PacifiCorp and Kemmerer Operations, LLC
Article 3.1 Environmental Response

II. Huntington Plant CSA– PacifiCorp and Wolverine Fuels, LLC
Article VIII Environmental Regulations

III. Colstrip Plant CSA – PacifiCorp and Westmoreland Rosebud Mining, LLC
Article 8.1 Changes in Applicable Law

(a) Please refer to the Company's response below, referencing items I through III above:

I. Naughton Plant CSA – **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** tons per year.

II. Huntington Plant CSA – **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** after an interim period and under certain conditions in the agreement.

III. Colstrip Plant CSA – **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** under certain conditions in the agreement.

(b) Yes – PacifiCorp ceased burning coal at Naughton Unit 3 on January 30, 2019 in compliance with the requirements of the Wyoming Regional Haze state implementation plan. To accommodate that environmental compliance requirement, on March 12, 2015, PacifiCorp exercised the provision contained in the Naughton Plant CSA that allowed it to reduce the minimum purchase obligation for coal. This action reduced the minimum volume requirement from **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** per year to **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**.

(c) The Company exercised the environmental provision in Naughton's coal supply contract to mitigate take-or-pay expense related to statutory environmental law changes.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 390 / PacifiCorp
June 1, 2021
Sierra Club Data Request 2.8

Sierra Club Data Request 2.8

Please refer to Mr. Ralston's public testimony filed as part of the 2021 TAM proceeding (UE 375), specifically PAC/300 at Ralston/3:18-19, wherein Mr. Ralston states, "Bridger Coal Company coal deliveries can be flexed down to satisfy the Jim Bridger plant's requirements, as necessary".

(a) Please specify any limitations on the ability to "flex down" coal deliveries from the Bridger Coal Company.

(b) Please indicate the reason for any limitation identified in response to subpart

Confidential Response to Sierra Club Data Request 2.8

(a) In the 2022 transition adjustment mechanism (TAM), Bridger Coal is projected to deliver **[Confidential Begins]** [redacted] **[Confidential Ends]** tons of coal. The coal delivered quantity of **[Confidential Begins]** [redacted] **[Confidential Ends]** is comprised of **[Confidential Begins]** [redacted] **[Confidential Ends]** tons of base coal deliveries and **[Confidential Begins]** [redacted] **[Confidential Ends]** tons of incremental coal deliveries. Bridger Coal's optional "flex down" quantity in the 2022 TAM is the incremental tonnage amount.

(b) Bridger Coal's base mine plan represents a balanced operating level that is required to maintain a core set of skills at the mine enabling Bridger Coal to respond to future potential coal demand increases and complete reclamation as required by federal and state regulations. Coal production and delivery quantities below this amount could impact the mine's ability to increase coal deliveries in the near-term. At Bridger Coal, mine plans are developed on an annual basis and base volumes are determined by balancing short-term and medium-term fueling needs. While in the short-term incremental tonnage is the basis for the "flex down" amount, the medium-term base tonnage can also be adjusted depending on the forecasted fuel usage.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

UE 390 / PacifiCorp
June 1, 2021
Sierra Club Data Request 2.19

Sierra Club Data Request 2.19

Please refer to PAC/200 at Ralston/19:11-12 which states: "The pricing for 2022 is an estimate based on preliminary discussions with the Kemmerer mine".

(a) Please provide all email records regarding PacifiCorp's preliminary discussions with the Kemmerer mine referenced above.

Response to Sierra Club Data Request 2.19

(a) PacifiCorp objects to this request as overly burdensome, outside the scope of this proceeding, and not reasonably calculated to lead to admissible evidence. PacifiCorp's transition adjustment mechanism (TAM) sets forward looking net power costs (NPC) and final coal contract prices are included and updated in a manner consistent with the TAM guidelines and past Public Utility Commission of Oregon (OPUC) precedent. The scope of the proceeding does not include any prudency review prior to the execution of a coal supply agreement (CSA). Additionally, any disclosure of such highly sensitive, and extremely confidential communications would severely harm PacifiCorp's ability to negotiate prices in a least-cost manner to the benefit of customers. Without waiving the foregoing objection, PacifiCorp responds as follows:

The estimated pricing for the 2022 costs at the Naughton facility are based on a general understanding of the conditions at the Kemmerer mine and reflects the best judgement of PacifiCorp's thermal generation and mining division.

UE 390 / PacifiCorp
June 1, 2021
Sierra Club Data Request 2.22

Sierra Club Data Request 2.22

CONFIDENTIAL REQUEST – Please provide a GRID model run that is identical to the base TAM 2022 model run except for the following changes:

(a) The dispatch tier price for Jim Bridger is changed from **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** to **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**.

(b) All take-or-pay penalties, liquidated damages, and any fixed costs associated with the BCC mining operation are set to zero (i.e., there would be no final "reaveraging" step to account for these costs).

Response to Sierra Club Data Request 2.22

Referencing the Stipulation that was adopted in the 2021 transition adjustment mechanism (TAM), Docket UE 375, specifically paragraph 15 (Transition to AURORA for Modeling NPCs), page 6, subpart b., lines 3 through 6 which states "PacifiCorp would additionally agree to conduct one AURORA model run per intervenor, so long as the request is reasonable and PacifiCorp has a reasonable time to complete the request during future NPC forecast mechanism proceedings." Although the 2022 TAM utilizes the Generation and Regulation Initiative Decision Tool (GRID), not AURORA, the Company is honoring the intent of the stipulated paragraph referenced above and hereby provides the following response regarding the "one AURORA [GRID] model run per intervenor." Based on the foregoing clarification, the Company responds as follows:

Please refer to Confidential Attachment Sierra Club 2.22. The Company wishes to make clear that no change apart from the proposed modification to the Jim Bridger dispatch tier price was undertaken. There was no subsequent re-averaging step included in this study. The Company would further like to point out that the absence of a re-averaging step that is inclusive of all cost components invalidates this study as a means by which to determine the impact of the proposed change on net power costs (NPC). This study, by definition, does not include all relevant inputs to a reasonable NPC estimate.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

Docket No. UE 390
Exhibit Sierra Club/104
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

EXHIBIT SIERRA CLUB/104

Exhibit Accompanying the Opening Testimony of Ed Burgess

PacifiCorp Response to OPUC Data Request 57

UE 390 / PacifiCorp
May 7, 2021
OPUC Data Request 57

OPUC Data Request 57

Please refer to PAC/100, Webb/13. Regarding the statement "a comparison of avoided fuel costs against start-up costs almost never weighs in favor of cycling a unit off outside of the spring runoff season", please provide the quantitative analysis supporting this assertion.

Response to OPUC Data Request 57

Please refer to the Economic Coal Cycling Study which was filed with the Public Utility Commission of Oregon (OPUC) on March 3, 2021 in Docket UE 375 (the 2021 Transition Adjustment Mechanism (TAM)) in response to direction from the OPUC in their final ruling in docket UE 375. A copy of the Economic Coal Cycling Study is provided as Confidential Exhibit PAC/107 to the direct testimony of Company witness, David G. Webb. Allowing cycling reduced coal generation by only three percent, resulted in an operationally infeasible dispatch forecast, and utilized the certainty inherent in a deterministic model, but unavailable in actual operational decisions.

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

EXHIBIT SIERRA CLUB/105

Exhibit Accompanying the Opening Testimony of Ed Burgess

Excerpts from 2021 ECAC Evidentiary Hearing Transcript in California Public Utilities Commission Proceeding A.20-08-002

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE

STATE OF CALIFORNIA

ADMINISTRATIVE LAW JUDGE JOHN LARSEN, presiding

	)	
	)	EVIDENTIARY
In the Matter of the Application of	)	HEARING
PacifiCorp (U901E) for Approval of	)	
its 2021 Energy Cost Adjustment	)	
Clause and Greenhouse Gas-Related	)	
Forecast and Reconciliation of Costs	)	Application
and Revenue.	)	20-08-002
	)	
	)	

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May 25, 2021
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Volume 1
PUBLIC

Reported by: Doris Human, CSR No. 10538
Karly Powers, CSR No. 13991
Shannon Ross, CSR No. 8916

I N D E X

utilized in the iOpt model for Jim Bridger is more or less the same as the Bridger Mine supplemental price?

A That is right.

Q And that was the price that was utilized in each iOpt Forecast conducted from January 2019 through May 2020?

A Yes. That is correct.

Q In order to receive the supplemental pricing from the Bridger Mine, is it necessary for PacifiCorp to purchase all of the coal under the base mine plan first?

A Yes. That is my understanding, but, again, Mr. Ralston would be -- could talk specifically about the mine plan and any coal contract. He would be the witness to ask about that.

Q Okay. I just have one more question, and I'll see if it's right for you or Mr. Ralston.

Since the supplemental pricing is only available after base costs have been paid, is it also true that if GRID finds that consuming the base quantities is not least cost, then PacifiCorp would not access the supplemental tier because there would be no need for that additional coal?

the more risk you take for that plant -- for price spikes and not having that plant available. Because, you know, they don't just turn on right away. Or for, you know, reliability purposes, if you need that plant or if you go to turn it on and it doesn't start up, which is -- which there's more risk in turning that plant on and off than there is just leaving it at the minimum.

Q   But the company hasn't completed any analysis demonstrating that the additional startup costs outweigh the benefits of economic cycling; isn't that right?

A   No, not necessarily true. Well, sorry. I think you asked me, "No, isn't that right?"

Q   I could -- I could rephrase the question.

A   Yeah.

Q   Has the company completed any specific analysis that would demonstrate that the avoided startup costs outweigh the benefit of economic cycling?

A   Sorry. Will you ask that again. You switched it up on me a little bit. So...

Q   Has PacifiCorp completed any

analysis demonstrating that additional startup costs outweigh the benefit of economic cycling?

A No. And the reason why is because logically it -- you know, we don't have to do an analysis to logically come to the conclusion that we've come to because it's not -- even though those startup costs are important, it's also the additional risk. And so like I said, having that plant offline and not being able to bring it up again creates more risk. So it's not just the additional startup costs, but it's also -- and that's important in the economic decision but also the risks that have that plant offline.

Q Would you agree that an economic dispatch modeling based on marginal costs would consider the potential fuel costs savings that might come from displacing coal plant generation with less expensive resources?

A Yes. Given the constraints that it has. And so, you know, on our system, we have constraints that are included in the model. And so yes, I would agree that an economic model would produce an economic solution and an optimized solution within the issues, just let me know.

A   Okay.

Q   Can you identify the document?

A   Yes. It's Sierra Club Data Request 9.6.

Q   Okay. So subpart B of this data request indicates that the Bridger Mine section is able to flex down in 2021; is that correct?

A   Yes.

Q   And that reduction exclusively comes from the surface mine; is that right?

A   That's correct.

Q   I'm going to refer you back to your Rebuttal Testimony, PAC-900, page 15.

A   All right.

Q   Looking at lines 1 through 8, you state here:

> Under the average-cost GRID run, a minimum take penalty was incurred from the Black Butte Coal Supply Agreement due to the fact that the Bridger Coal Mine coal deliveries could not be reduced by 73 percent.

Is that correct?

A   Yes. This was looking at a hypothetical average cost --

Q Correct.
A -- not looking at what the Commission approved on an incremental basis.
Q Correct.
The reason that you give for the inability to reduce Bridger coal deliveries by 73 percent -- and this is line 4 through 8 -- is that a steady rate of mining is required at BCC's underground mine to avoid adverse geological issues that would negatively impact productivity rates, coal quality, operating costs. It could create unsafe working conditions; is that correct?
A That's correct.
Q Okay. So, now, referring back to SC Exhibit 27-C.
A Okay.
Q Subpart B again:

> This response indicates that PacifiCorp is able to flex the surface mine up or down.

Is that correct?
A That is correct.
Q And so is it true that the underground mine is unable to flex down?
A We have to keep a minimum to avoid the adverse geological conditions. In that number there in the data request is what we

believe is the minimum we need to do to keep a safe and productive work environment.

Q Okay. So just to say that another way and to make sure I'm perfectly clear: The underground mine production volume is at its minimum?

A Yes, it is. And the underground mine is scheduled to close at the end of this year.

Q Okay. So those concerns that you had cited, the adverse geological issues and unsafe working conditions, those things are associated with the underground mine; is that correct?

A That is correct.

Q And they would, you know, immediately start to happen if production decreased any more than current levels; is that correct?

A "Immediate" is probably a strong word. It would start to show up very quickly.

Q Can you give a ballpark of what "very quickly" means.

A A few days.

Q Okay. So those issues, the geological issues, unsafe working conditions, that are -- those are associated with the underground mine, but could you explain why the surface mine is unable to reduce production below the figure that's provided in SC-27-C.

A Over time, yes, we could. We'd have to redo the mine plan and dispatch the people and things a different way. This is what we had done for the initial mine plan for this test period or this period here.

So, yes. It can flex down more, but, again, that will -- for a one-year view, a lot of the consumable -- or a lot of the cost will not go away unless we can redirect it toward reclamation.

Q Okay. I would like to move in some questions about PacifiCorp's coal contracting practices. I understand there's a lot of confidential information here. And so, again, I have attempted to structure my questions to let you know if we need to go into confidential information, but if my questions would elicit a confidential response, just let me know.

A All right.

Q And I understand also that Mr. MacNeil presented testimony on the analysis completed in preparation for contract negotiations at the Hunter plant,

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EXHIBIT SIERRA CLUB/106

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to Sierra Club Data Request 1.4

This exhibit is confidential pursuant to Protective Order 16-128 and is provided under separate cover.

PUBLIC UTILITY COMMISSION OF OREGON

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EXHIBIT SIERRA CLUB/107

HIGHLY CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Coal Supply Agreement with the Trapper Mine

This exhibit is highly confidential pursuant to Modified Protective Order No. 21-086.

Please note, Sierra Club does not have access to copies of PacifiCorp's highly confidential documents. Sierra Club intends to motion for inclusion of relevant highly confidential materials at or before hearing.

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EXHIBIT SIERRA CLUB/108

HIGHLY CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Coal Supply Agreement with Peabody Coal Sales, LLC (Caballo Mine)

This exhibit is highly confidential pursuant to Modified Protective Order No. 21-086.

Please note, Sierra Club does not have access to copies of PacifiCorp's highly confidential documents. Sierra Club intends to motion for inclusion of relevant highly confidential materials at or before hearing.

Docket No. UE 390
Exhibit Sierra Club/109
Witness: Ed Burgess

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EXHIBIT SIERRA CLUB/109

HIGHLY CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Coal Supply Agreement with Peabody Coal Sales, LLC
(North Antelope Rochelle Mine)

This exhibit is highly confidential pursuant to Modified Protective Order No. 21-086.

Please note, Sierra Club does not have access to copies of PacifiCorp's highly confidential documents. Sierra Club intends to motion for inclusion of relevant highly confidential materials at or before hearing.

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Exhibit Sierra Club/110
Witness: Ed Burgess

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EXHIBIT SIERRA CLUB/110

HIGHLY CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Coal Supply Agreement with Bronco Utah Operations, LLC

This exhibit is highly confidential pursuant to Modified Protective Order No. 21-086.

Please note, Sierra Club does not have access to copies of PacifiCorp's highly confidential documents. Sierra Club intends to motion for inclusion of relevant highly confidential materials at or before hearing.

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Exhibit Sierra Club/111
Witness: Ed Burgess

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EXHIBIT SIERRA CLUB/111

HIGHLY CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Coal Supply Agreement with Wolverine Fuels, LLC

This exhibit is highly confidential pursuant to Modified Protective Order No. 21-086.

Please note, Sierra Club does not have access to copies of PacifiCorp's highly confidential documents. Sierra Club intends to motion for inclusion of relevant highly confidential materials at or before hearing.

Docket No. UE 390
Exhibit Sierra Club/112
Witness: Ed Burgess

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EXHIBIT SIERRA CLUB/112

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Selected Confidential PacifiCorp Data Responses

This exhibit is confidential pursuant to Protective Order 16-128 and is provided under separate cover.

PUBLIC UTILITY COMMISSION OF OREGON

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EXHIBIT SIERRA CLUB/113

Exhibit Accompanying the Opening Testimony of Ed Burgess

PacifiCorp Response to OPUC Data Request 72

UE 390 / PacifiCorp
May 7, 2021
OPUC Data Request 72

OPUC Data Request 72

Please refer to PAC/200, Ralston/10. Regarding the statement "The Company performed detailed analysis on the near term needs based on the economic conditions known prior to contract execution", please describe the analysis steps and/or methodologies underlying the detailed analysis.

Confidential Response to OPUC Data Request 72

Dave Johnston – the Company's July 16, 2020 coal generation forecast for its 10-year business plan / budget plan came initially from Generation and Regulation Initiative Decision Tool (GRID) production cost model run results. GRID is a production cost optimization model that seeks maximum cost effectiveness in ideal power market economics. The initial GRID modeled forecast was reviewed for operating feasibility and reasonableness. Due to GRID model functionality limitations, such as lack of tiered coal fuel price settings based on same year cumulative coal consumptions, in the budget planning net power costs (NPC) forecast report, the coal generation forecast from the initial GRID run included top-side adjustments that reallocated the coal generation forecast among same region coal plants following each coal plant's minimum take coal consumption constraints, tiered coal price cost impact, etc. Note: there was no top-side adjustments to the July 16, 2020 coal generation forecast for the Dave Johnston plant in the 10-year business plan model runs. With the December 9, 2020 coal generation forecast, an update to the top-side adjustments was made to the Dave Johnston plant which reduced its generation by **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** megawatt-hours (MWh) in 2021, with those MWh redistributed to the Hunter plant and the Huntington plant. Based on the December 9, 2020 top-side adjustments, the coal generation forecast for the Dave Johnston plant for 2021 was reduced from **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** in an effort to increase the coal generation forecasts of the Hunter plant and the Huntington plant. Note: the December 9, 2020 updated coal generation forecast also started with a GRID run, and then was adjusted at the report level to keep coal consumption constraints intact.

Hunter – Scenarios for the time period 2021 through 2023 were developed starting from the Company's avoided cost GRID model as of May 2020, which included executed contracts and future resources identified in PacifiCorp's 2019 Integrated Resource Plan (IRP) preferred portfolio. GRID was used to identify a range of Hunter generation levels, based on four different potential Hunter coal costs and three levels of system demand.

In addition to the modeled generation output reported by GRID, additional expected generation was added to account for the fuel requirement of the joint owners at Hunter, ramping requirements not captured within the GRID logic, and expected energy imbalance market (EIM) dispatch. The expected level of system demand used standard GRID inputs and assumptions for market purchases and sales. For the "low" system demand scenario, all wholesale sales were eliminated at the less liquid markets modeled in GRID: California-Oregon Border (COB), Mona, Mead, and Four Corners (4C). In addition, for the low scenario, no EIM dispatch energy was added. For the "high" system demand scenario, all wholesale purchases were eliminated and EIM dispatch energy was increased, such that a greater portion of the periods in which a unit was economic based on historical EIM prices were assumed to result in generation.

Craig - The negotiations for the new agreement were based upon a generation forecast that was part of the overall fueling budget for the Company developed in July 2020 and was further updated in December 2020. The five-year average of coal consumption in the business plan developed July 2020 was approximately by **[CONFIDENTIAL BEGINS]**[redacted]**[CONFIDENTIAL ENDS]** tons. In the December 2020 update, the five-year average coal consumption increased and was approximately by **[CONFIDENTIAL BEGINS]**[redacted]**[CONFIDENTIAL ENDS]** tons. Both of these averages exceed the annual minimum tonnage nomination of by **[CONFIDENTIAL BEGINS]**[redacted]**[CONFIDENTIAL ENDS]** tons under the agreement. The pricing under the coal supply agreement is based upon Trapper mine's annual costs. These costs are derived from the mine's annual budgeting approval process, which supports specific detailed mine plans and agreed upon nominated tonnage volumes.

Please refer to Confidential Attachment OPUC 71-1 and Confidential Attachment OPUC 71-2 for the generation forecast that was used when negotiating and signing the new agreements.

Confidential information is designated as Protected Information under the protective order in this proceeding and may only be disclosed to qualified persons as defined in that order.

Docket No. UE 390
Exhibit Sierra Club/114
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

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EXHIBIT SIERRA CLUB/114

Exhibit Accompanying the Opening Testimony of Ed Burgess

PacifiCorp Response to Sierra Club Data Request 8.9 in California Public Utilities Commission Proceeding A.20-08-002

A.20-08-002/ PacifiCorp
February 25, 2021
Sierra Club Data Request 8.9

Sierra Club Data Request 8.9

Please provide the time period and required output level (in MWh) for the must run constraints for each coal plant for each run. Please refer to PAC/700 at Ralston/4: 22- 23, which states: "The negotiations for the new agreements were based upon a generation forecast that was part of the overall fueling budget for the Company" and Ralston/6:1-13 which states: "Before the two new agreements were signed, an updated generation forecast for the plant was completed".

(a) Please provide the generation forecasts and fueling budgets used for these negotiations, including any details regarding:

i. The date the forecasts were completed,

ii. The GWh output forecasted for each of PacifiCorp's generation units, and

iii. The forecasted fuel cost for each of PacifiCorp's generation units

(b) Please describe in detail how these generation forecasts were developed, including any tools, models, or simulations used (e.g. GRID).

(c) Please provide any key assumptions used in developing the generation forecasts, including:

i. Minimum take requirements,

ii. Minimum burn or Must-Run constraints,

iii. Fuel price assumptions, and

iv. Whether the fuel price assumptions reflect the average or incremental fuel cost.

Confidential Response to Sierra Club Data Request 8.9

Based on the referenced Supplemental Testimony of Company witness, Dana M. Ralston, the Company responds with information specific to analysis / generation forecasts performed for the Dave Johnston and Hunter plants.

(a) Please refer to the Company's responses to subparts i. through iii. below:

i. **<u>Dave Johnston</u>** – the generation forecast modeling date for fueling budget year 2021 to 2030 was July 16, 2020. The Company's updated generation forecast for year 2021 to 2024 was dated December 9, 2020.

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Hunter – the generation forecast modeling was completed on June 22, 2020, and that modeling assessed expected output over scenarios that spanned a range of potential future conditions. A review of the status of key inputs relative to the June 22, 2020 scenarios was completed on December 10, 2020.

ii. **Dave Johnston** – for details of the analysis, please refer to Confidential Attachment SC 8.9-1.

Hunter – for details of the June 22, 2020 analysis, please refer to Confidential Attachment SC 8.9-2.

iii. **Dave Johnston** – for details of the analysis, please refer to Confidential Attachment SC 8.9-1.

Hunter – for details of the June 22, 2020 analysis, please refer to Confidential Attachment SC 8.9-2. A range of potential Hunter fuel costs were evaluated, please refer to tab "Summary", column B, for details. For other units, please refer to tab "Incremental by volume".

(b) **Dave Johnston** – the Company's July 16, 2020 coal generation forecast for its 10-year business plan / budget plan came initially from Generation and Regulation Initiative Decision Tool (GRID) production cost model run results. GRID is a production cost optimization model that seeks maximum cost effectiveness in ideal power market economics. The initial GRID modeled forecast was reviewed for operating feasibility and reasonableness. Due to GRID model functionality limitations, such as lack of tiered coal fuel price settings based on same year cumulative coal consumptions, in the budget planning net power costs (NPC) forecast report, the coal generation forecast from the initial GRID run included top-side adjustments that reallocated the coal generation forecast among same region coal plants following each coal plant's minimum take coal consumption constraints, tiered coal price cost impact, etc. Note: there was no top-side adjustments to the July 16, 2020 coal generation forecast for the Dave Johnston plant in the 10-year business plan model runs. With the December 9, 2020 coal generation forecast, an update to the top-side adjustments was made to the Dave Johnston plant which reduced its generation by **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** megawatt-hours (MWh) in 2021, with those MWh redistributed to the Hunter plant and the Huntington plant. Based on the December 9, 2020 top-side adjustments, the coal generation forecast for the Dave Johnston plant for 2021 was reduced from **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** in an effort to increase the coal generation forecasts of the Hunter plant and the Huntington plant. Note: the December 9, 2020 updated coal generation forecast also started with a GRID run, and then was adjusted at the report level to keep coal consumption constraints intact.

Hunter – Scenarios for the time period 2021 through 2023 were developed starting from the Company's avoided cost GRID model as of May 2020, which included executed contracts and future resources identified in PacifiCorp's 2019 Integrated Resource Plan (IRP) preferred portfolio. GRID was used to identify a range of Hunter generation levels, based on four different potential Hunter coal costs and three levels of system demand.

In addition to the modeled generation output reported by GRID, additional expected generation was added to account for the fuel requirement of the joint owners at Hunter, ramping requirements not captured within the GRID logic, and expected energy imbalance market (EIM) dispatch. The expected level of system demand used standard GRID inputs and assumptions for market purchases and sales. For the "low" system demand scenario, all wholesale sales were eliminated at the less liquid markets modeled in GRID: California-Oregon Border (COB), Mona, Mead, and Four Corners (4C). In addition, for the low scenario, no EIM dispatch energy was added. For the "high" system demand scenario, all wholesale purchases were eliminated and EIM dispatch energy was increased, such that a greater portion of the periods in which a unit was economic based on historical EIM prices were assumed to result in generation.

(c) **Dave Johnston** – the following key assumptions for coal generation forecasts implemented in the Company's 10-year business plan / budget plan were:

i. Coal plants that have "take-or-pay" clauses in existing coal supply agreements (CSA) required to be met. The coal plants that have minimum take requirement were: Jim Bridger, Colstrip, Hayden, Hunter, Huntington, and Naughton.

ii. All shared units were set as "must-run" in GRID regardless of market economics including: Colstrip, Craig, Hayden, Hunter Unit 1, Hunter Unit 2, Jim Bridger and Wyodak. Note: The Dave Johnston, Hunter Unit 3, Huntington and Naughton plants are capable of cycling with market movements and were therefore not set as "must run."

iii. All coal plants' incremental coal prices were used in GRID for dispatch decisions. "Must-run" units would generate at the minimum generation level in the "out-of-the-money" hour and generate the maximum dependable capacity. "Can-cycle" coal plants could be backed down when "out-of-the-money" within minimum on / maximum off time constraints.

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iv. All coal units modeled in GRID used incremental coal prices. Average coal costs were calculated in the NPC report.

The updated coal generation forecast used the same assumptions as for the 10-year business plan / budget plan described above, but with the following additional updates:

i. New market price curve forecast as of December 8, 2020.

ii. Coal plant variable costs were updated.

iii. The delayed Wyoming wind project development impacted the generation forecast in 2021.

Hunter – the key inputs include:

- March 2020 official forward price curve (OFPC).
- June 2019 Load Forecast.
- IRP Resources – 2019 IRP preferred portfolio published October 18, 2019.

i. Coal plants that have "take-or-pay" clauses in existing CSAs required to be met. No minimum take was assumed for the Hunter resources and incremental coal costs for Jim Bridger and Huntington were adjusted in concert with Hunter fuel cost assumptions to ensure projected Hunter operations were consistent with the existing obligations for those other facilities. Smaller facilities that also have assumed "take-or-pay" obligations include Colstrip, Hayden, and Naughton.

ii. Hunter Unit 1 and Hunter Unit 2 were allowed to cycle in the spring, consistent with assumptions previously used in Oregon Transition Adjustment Mechanism (TAM) filings. No other coal units were allowed to cycle.

iii. All coal plants' incremental coal prices were used in GRID for dispatch decisions.

iv. All coal units modeled in GRID used incremental coal prices. Note: the fuel price points evaluated in the Hunter analysis are representative of a contract with identical average and incremental costs.

For the review of key inputs for the Hunter analysis in December 2020, the Company assessed the impact of the following:

- November 9, 2020 OFPC – generally higher than the March 2020 OFPC, which would lead to higher expected coal consumption.

- June 2020 Load Forecast – the updated load forecast was lower in 2021 and 2022 but generally well above the "low" scenario in the original analysis.

- New resources and transmission – executed contracts were lower or delayed relative to the expected amounts contemplated in the 2019 IRP. In addition, the Energy Gateway South transmission line was expected to be delayed from year-end 2023 into 2024. Both of these changes would lead to higher expected coal consumption.

Confidential information is provided subject to the terms and conditions of the non-disclosure agreement in this proceeding between PacifiCorp and Sierra Club.

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Exhibit Sierra Club/115
Witness: Ed Burgess

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EXHIBIT SIERRA CLUB/115

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment OPUC 71-1

This exhibit is confidential pursuant to Protective Order 16-128 and is provided in Excel format.

Docket No. UE 390
Exhibit Sierra Club/116
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

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EXHIBIT SIERRA CLUB/116

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to Sierra Club Data Request 1.6

This exhibit is confidential pursuant to Protective Order 16-128 and is provided under separate cover.

Docket No. UE 390
Exhibit Sierra Club/117
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

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EXHIBIT SIERRA CLUB/117

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment OPUC 71-2

This exhibit is confidential pursuant to Protective Order 16-128 and is provided in Excel format.

Docket No. UE 390
Exhibit Sierra Club/118
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

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EXHIBIT SIERRA CLUB/118

Exhibit Accompanying the Opening Testimony of Ed Burgess

Redacted PacifiCorp Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant

PACIFICORP CONFIDENTIAL LONG-TERM FUEL SUPPLY PLAN FOR THE JIM BRIDGER PLANT

March 2018

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

CONTENTS

1 INTRODUCTION AND EXECUTIVE SUMMARY

In the final order in PacifiCorp's 2014 Transition Adjustment Mechanism (TAM) filing, Order No. 13-387, the Public Utility Commission of Oregon (Oregon Commission) adopted PacifiCorp's proposal to prepare periodic fuel supply plans comparing affiliate mine supply to alternative fuel supply options, including market alternatives. In December 2015, PacifiCorp complied with Order No. 13-387 by providing "PacifiCorp's Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant" (2015 Fuel Plan). Subsequently, PacifiCorp committed in testimony to provide periodic updated filings to the 2015 Fuel Plan. In its orders in the 2017 and 2018 TAMs, the Oregon Commission directed PacifiCorp to hold workshops to discuss information and analyses required to meaningfully evaluate long-term fueling plans for the Jim Bridger plant. To date, three different workshops have been held with the Oregon staff and intervenors to discuss various details and assumptions associated with the development of the updated PacifiCorp Confidential Long-Term Fuel Supply Plan for the Jim Bridger Plant (2018 Fuel Plan).

As set forth in PacifiCorp's compliance filing in docket UE 287, the purpose of long-term fuel supply plans for plants fueled from captive mines is to determine the least-cost, least-risk coal supply evaluated on a multi-year basis. The long-term fuel supply plan is designed to ensure that fuel supplies are fair, just and reasonable, and that they satisfy the Oregon Commission's prudence and affiliate interest standards.

Additionally, PacifiCorp agreed to provide a long-term fueling strategy for the Jim Bridger plant in the stipulation Settlement Agreement to the 2015 Wyoming Energy Cost Adjustment Mechanism (ECAM) filing (docket 20000-472-EA-15). The evaluation would include coal supply pricing, transportation and modifications to the plant for an alternative fuel supply. The report would be updated periodically to address significant milestones.

To develop the 2018 Fuel Plan, PacifiCorp has studied, reviewed and evaluated different fueling options for the Jim Bridger plant. For the 2018 Fuel Plan, the annual generation requirements expressed in consumed tons were derived from PacifiCorp's budget which is calculated using PacifiCorp's Generation and Regulation Initiative Decision Tools (GRID) model[1]. The generation requirements derived from the GRID model have also been used for the basis of PacifiCorp's 2017 Integrated Resource Plan (IRP) Update. Within the 2018 Fuel Plan, different fueling options are presented. The fueling options consider varying tonnage delivery schedules sourced from Bridger Coal Company (Bridger mine), the Black Butte mine, and mines located in Wyoming's Southern Powder River Basin (SPRB), which are "8,800" Btu/lb. mines. Additionally, the different coal delivery options for the Bridger mine contain various mine plan scenarios outlining specified tonnage delivery schedules from both the underground and surface mining operations. Included in these different mine scenarios are estimated shutdown dates for Bridger mine's underground and surface operations. The 2018 Fuel Plan provides third party coal supply tonnages and pricing estimates based upon recent negotiations, as well as recent coal pricing forecasts from Energy Ventures Analysis (EVA). The 2018 Fuel Plan provides estimated tonnage volumes and rail rates for transportation services provided by the Union Pacific Railroad for the transport of coal from third party coal supply sources. The estimated plant modifications and capital requirements, defined by equipment category, as well as total costs needed to support large volumes of SPRB coal are presented in a detailed third party study completed in 2017 by the engineering and consulting firm Burns & McDonnell.

[1] The GRID model used for budget purposes is different than the GRID model used in the Oregon TAM. The budget GRID model is used to determine the net power cost budget, but is not subject to the same normalizing and regulatory modeling constraints as the GRID model used in the Oregon TAM.

After considering all of the factors influencing long-term fueling strategy, the Company developed and evaluated six different Jim Bridger plant fueling options. A Present Value Revenue Requirement (PVRR) calculation was completed for the various fueling options and includes a composite ranking considering both financial and risk weighting. Based upon the results of the detailed PVRR analysis and utilizing a risk profile, Option F ([redacted]) is the current least-cost, least-risk option. While the current analyses shows Option F as the least-cost, least-risk option, Option D is the lowest cost option and will continue to be analyzed. PacifiCorp will continue to evaluate the best fueling option for the Jim Bridger plant taking in to consideration both cost and risk of the different options and will change the long-term fuel supply plan as necessary to provide the least-cost, least-risk fuel supply for the Jim Bridger plant.

The benefits of pursuing Option F as the long-term fueling strategy for the Jim Bridger plant include the following:

- [redacted]
- [redacted])
- [redacted]
- [redacted]
- [redacted]
- [redacted]

2 BACKGROUND

The Jim Bridger plant is a four unit coal-fired plant located in Sweetwater County, Wyoming. The facility is located approximately eight miles north of Point of Rocks, Wyoming, and approximately 24 miles east of Rock Springs, Wyoming.

The Jim Bridger plant is the largest power plant on the PacifiCorp system (2,120 megawatts) and is jointly owned by PacifiCorp (66.7%) and Idaho Power Company (Idaho Power) (33.3%). The Jim Bridger plant consists of four almost identical units, each with a nominal 530 net megawatt capacity. Over the past two years, Jim Bridger plant has consumed approximately 6.6 million tons of coal per year. From 2006 to 2015, the Jim Bridger plant consumed on average 8.0 million tons per year. The plant is designed to burn coal sourced from southwest Wyoming with heat content in the range of 9,000 Btu/lb. to 10,000 Btu/lb. The depreciable life of PacifiCorp's share of the Jim Bridger plant extends through 2025 in Oregon and through 2037 in all other states based on PacifiCorp's 2012 depreciation study.

The Bridger mine is located adjacent to the Jim Bridger plant. The Bridger mine includes both surface and underground mining operations and, similar to the Jim Bridger plant, is jointly owned by PacifiCorp (66.7%) and Idaho Power (33.3%). The surface operation consists of a combination dragline and truck/loader operation that produces approximately [redacted] million tons of coal per year. Bridger mine's underground operation uses continuous miners and longwall mining equipment to produce coal. The underground mine produces approximately [redacted] million tons of coal per year. The coal is transported from both the underground and surface mining operations to surface stockpiles or directly to the Jim Bridger plant via a nine mile overland conveyor system.

For regulatory purposes, Bridger mine is consolidated with PacifiCorp's operations. PacifiCorp's share of Bridger mine is included in the PacifiCorp rate base and its share of mining costs, including depreciation and depletion, is included in net power costs.

In addition to the estimated [redacted] million tons of coal forecast to be delivered annually from the Bridger mine to the Jim Bridger plant, the Jim Bridger plant has historically received the remaining portion of its coal supply requirements, approximately [redacted] million tons per year, from the nearby Black Butte mine. The Union Pacific Railroad provides rail access for all the coal delivered from the Black Butte mine to the plant.

3 ASSUMPTIONS

The 2018 Fuel Plan for the Jim Bridger Plant was prepared in two phases. The key variables used in the plan were subject to in-depth review and study. These assumptions are explained below:

3.1 Evaluation – Phase 1

3.1.1 Generation

Generation assumptions are taken from PacifiCorp's budget GRID model and parallel PacifiCorp's 2017 IRP Update which will be submitted in May 2018, and are used in all evaluated alternatives. Consistent with the findings of the IRP, the 2018 Fuel Plan assumes the closure of Jim Bridger Unit 1 on December 31, 2028, and Jim Bridger Unit 2 on December 31, 2032. These assumptions represent a significant change from the assumed generation requirement used to evaluate the plant's fueling needs in the 2015 Fuel Plan. This plan assumed a total plant annual consumption of [redacted] million tons through the life of the plant.

Consistent with the IRP, coal consumption is shown to decline through 2037, the depreciable plant life. The assumed burn level is approximately [redacted] million tons per year for 2018 through 2022; approximately [redacted] million tons per year for 2023 through 2028; approximately [redacted] million tons per year for 2029 through 2032; and approximately [redacted] million tons per year through 2037. The assumed generation levels between the 2015 and 2018 Fuel Plans are compared in Appendix A.

3.1.2 Plant Depreciable Life

The assumed depreciable life of PacifiCorp's share of the Jim Bridger plant extends through 2025 in Oregon and through 2037 in all other states, based on PacifiCorp's 2012 depreciation study.

3.1.3 2015 Fuel Plan –"Base Operating Plan"

The 2015 Fuel Plan recommended fueling the plant under the Base Operating Plan. This plan consisted of the following main elements:

- Continued surface mining at Bridger mine through [redacted]
- Permitting and mining the Deadman Wash tract at Bridger mine
- Closure of the Bridger mine underground operations in [redacted] – remaining inventory delivered in [redacted]
- Continued purchase of Black Butte mine coal through [redacted]
- Conversion of the Jim Bridger plant to SPRB coal deliveries requiring estimated capital expenditures of [redacted] million (PacifiCorp share)
- [redacted] SPRB deliveries, replacing Black Butte coal deliveries, begin in [redacted] and continue through [redacted]
- Infrastructure improvements begin in [redacted] with infrastructure fully in place and operable by [redacted]

As mentioned above, the Base Operating Plan was recommended based on the assumption that Jim Bridger plant consumption would be between [redacted] and [redacted] million tons per year (total plant). Actual plant coal consumption for 2016 and 2017 was significantly less than the assumed consumption. Total coal consumption at the plant was [redacted] than expected in the Base Operating Plan over the two-year period as shown in Table 1.

TABLE 1

"Base Operating Plan" - 2015 Long-Term Fuel Supply Plan for the Jim Bridger Plant						
	2016		2017		Average	
	PacifiCorp	Total	PacifiCorp	Total	PacifiCorp	Total
Deliveries (Million Tons)						
Bridger Coal Company	[redacted]					
Black Butte Coal Company						
Consumption (Million Tons)						
Total						
Actual Tonnage Consumed at the Jim Bridger Plant						
	2016		2017		Average	
	PacifiCorp	Total	PacifiCorp	Total	PacifiCorp	Total
Deliveries (Million Tons)						
Bridger Coal Company	[redacted]					
Black Butte Coal Company						
Consumption (Million Tons)						
Total						
Variance in Tonnage Consumed at the Jim Bridger Plant						
	2016		2017		Average	
	PacifiCorp	Total	PacifiCorp	Total	PacifiCorp	Total
Deliveries (Million Tons)						
Bridger Coal Company	[redacted]					
Black Butte Coal Company						
Consumption (Million Tons)						
Total						
% Change						

The significant decrease in forecasted consumption required revisions to the recommended Base Operating Plan. [redacted] Effective March 2017, the Base Operating Plan was modified to include this change.

3.1.4 Further Refinement of the "Base Operating Plan"

In addition to the change mentioned above, an additional step was taken to further optimize the Base Operating Plan by determining the optimal closure plan for the Bridger mine underground mining operation. Bridger mine prepared four, [redacted] mine plans with varying underground closure dates. The mine production volume target was based on estimated consumption and purchases of third party coal. The four plans are summarized below:

- Underground Mine Option A –
    - Underground closure in [redacted]
    - Surface closure in [redacted]
- Underground Mine Option B –
    - Underground closure in [redacted]
    - Surface closure in [redacted]
- Underground Mine Option C –
    - Underground closure in [redacted]
    - Surface closure in [redacted]
- Underground Mine Option D –
    - Underground closure in [redacted]
    - Surface closure in [redacted]

Bridger mine's underground operations experienced a significant challenge with the mine's western reserves in 2015 and 2016. Based on knowledge gained from this experience, the Bridger mine reduced planned production in the area and accelerated the move to the mine's eastern reserves. Ultimately Underground Mine Option D with the underground closure in [redacted], emerged and was found to be the least-cost, least-risk option. Table 2 compares the results of the analysis in terms of (PVRR):

TABLE 2

PVRR Summary		
PVRR Summary (PacifiCorp Share)	PVRR (000's)	Differential (from lowest $)
[redacted]		
Financial Ranking & Operation Risk Ranking		
PVRR Summary (PacifiCorp Share)	Financial Ranking (low to high)	Operation Risk Ranking (low to high)
[redacted]		

The results of this analysis were presented to Oregon Commission staff in a workshop held March 1, 2017. The analysis established the Base Operating Plan as modified, consistent with Underground Mine Option D above as the new baseline for continued evaluation.

Underground Mine Option D – The March 2017 Base Operating Plan consists of the following main elements:

- Continued surface mining at Bridger mine through [redacted]
- Permitting and mining the Deadman Wash tract at Bridger mine
- Closure of Bridger mine underground operations in [redacted]
- Continued purchase of Black Butte mine coal through [redacted]
- SPRB coal deliveries from [redacted] continuing through [redacted] in quantities which will not require significant capital modifications at the plant

3.2 Evaluation – Phase 2

3.2.1 Economic closure of the Bridger mine surface operation

With the March 2017 Base Operating Plan established and the underground mine closure date determined, Bridger mine prepared three, [redacted] million ton per year mine plans. This level of production complemented expected future total plant consumption of [redacted] million tons per year and third party purchases. One of the options also considered was a complete conversion to SPRB deliveries as soon as practicable. The three mine plans are summarized as follows:

- Surface Mine Option D –
  - Underground closure in [redacted]
  - Surface closure in [redacted]
- Surface Mine Option E –
  - Underground closure in [redacted]

- Surface closure in [redacted]
- Surface Mine Option F –
  - Underground closure in [redacted]
  - Surface closure in [redacted]

The revised Surface Mine Option D mine plan maintained assumptions consistent with those described above for the March 2017 Base Operating Plan, except the assumed Bridger mine production level was reduced to reflect deliveries of [redacted] million tons per year from the [redacted] million tons per year level mentioned previously.

A fueling plan option based on Bridger mine's Surface Mine Option E mine plan assumed a complete conversion to the consumption of SPRB coal following the closure of both underground and surface mining operations at Bridger mine in [redacted]. A complete conversion was not possible prior to [redacted], due to the capital modifications required at the Jim Bridger plant to safely and reliably receive and consume SPRB coal in large volumes. As a result, the fueling options have been separated into "near-term" and "long-term" periods for discussion purposes. For purposes of the 2018 Fuel Plan, the near-term period has been defined as the next three-to-four years and corresponds to the estimated time required to design, procure and construct the capital infrastructure to successfully unload trains and consume coal originating in the SPRB.

Surface Mine Option F further developed Surface Mine Option D. The key change was the assumption of [redacted], avoiding [redacted] million ([redacted] million PacifiCorp share) in development costs, and closure of the Bridger mine surface mining operation in [redacted]. After closure of the Bridger mine surface mining operation, Surface Mine Option F supplements the Bridger mine deliveries with coal from both the [redacted].

3.2.2 Third Party Coal

Based on the location of the Jim Bridger plant, economic fuel supply alternatives are limited to two operating mines located in southwest Wyoming and the SPRB mines of Campbell County, Wyoming.

The Black Butte mine, 20 miles southeast of the Jim Bridger plant, is jointly owned by Lighthouse Resources Inc. (Lighthouse) and Anadarko Petroleum. Operated by Lighthouse, the mine is a multiple seam, multiple pit operation with the overburden removed by draglines and a truck/loader fleet. Historically, Black Butte mine has mined approximately 3.5 to 4.0 million tons per year, a significant portion of which has supplied the Jim Bridger plant. However, one of Black Butte mine's significant contracts has expired. The mine is now producing less than [redacted] million tons per year and the Jim Bridger plant is the mine's only customer. During 2016 and 2017, the Jim Bridger plant received approximately one-third of its fuel supplies from the Black Butte mine under a contract that will terminate in [redacted]. Coal from the Black Butte mine is delivered by rail to the Jim Bridger plant under an agreement with the Union Pacific Railroad.

The other southwest Wyoming mine is Westmoreland's Kemmerer mine. In 2017, Westmoreland purchased the idled Haystack mine located 30 miles south of the Kemmerer mine. Presently the Kemmerer mine supplies PacifiCorp's Naughton plant and southwest Wyoming's trona (soda ash) industry. The Kemmerer mine coal is delivered to customers via overland conveyor, truck transportation and limited rail operations. Presently the Kemmerer mine's rail loading infrastructure is incapable of loading a full unit train efficiently. In addition, the grade elevation surrounding the mine requires additional locomotives to power a full unit train. As a result, the mine very rarely loads full unit trains. Given the Kemmerer mine's current rail loading infrastructure, rail delivery of coal would only be viable on a limited scale. Delivery of a sizable volume of Kemmerer coal to the Jim Bridger plant would require more costly truck transportation. [redacted].[2]

The Powder River Basin is the largest coal mining region in the United States. Coal from the SPRB is classified as sub-bituminous coal. SPRB coal contains an average heat content of approximately 8,800 Btu/lb. The coal mined in the SPRB is low sulfur and low ash. Due to its unique quality characteristics, SPRB coal has been consumed by energy markets in multiple states across the country. In 2017, there were eight different mining companies operating fourteen active mines in the Powder River Basin, producing roughly 300 million tons. SPRB mines contain the highest heat content coal ranging between 8,600 Btu/lb. and 8,950 Btu/lb. These mines are located about 550 miles from the Jim Bridger plant.

SPRB mines are served by the Union Pacific Railroad and Burlington Northern Santa Fe Railway railroads. Both of these railroads have joint access to all of the mines located south of Gillette, Wyoming, in the SPRB.

3.2.3 **Black Butte Pricing**

[redacted]

[redacted]

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

[redacted]

[2] See footnote [redacted].

TABLE 3

CONTRACT PROPOSALS - ANNUAL VOLUME & PRICING					
Proposal A	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					
Proposal B	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					
Proposal C	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					
Proposal D	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					
Proposal E	**2018**	**2019**	**2020**	**2021**	**Total**
Take-or-Pay Volume	[redacted]				
Price Per Ton					
Total $					
Btu/lb					
MMBtus					
$/MMBtu					

The least-cost, least-risk option for the near-term was identified by comparing the cost of purchasing incremental volume from Black Butte mine to the cost of producing incremental volume at Bridger mine. The comparison consisted of the following two options:

1. [redacted] (Black Butte mine Proposal A)
2. [redacted] (Black Butte mine Proposal D)

Other options were considered and evaluated, but were found to not be economically viable. Specifically, an option considering Bridger mine deliveries at [redacted] million tons per year and Black Butte mine deliveries at [redacted] million tons per year is discussed in the following pages.

The Company ultimately selected Black Butte mine's Proposal A as the least-cost, least-risk coal supply option for the near-term. Proposal A preserves flexibility to further assess and implement long-term fuel options before making any long-term, large capital investments. Table 4 details the delivered cost savings of [redacted] million to PacifiCorp from purchasing coal under the selected option:

TABLE 4

PacifiCorp Share						
[redacted] (Black Butte Mine - Proposal A)						
Mine	*2018*	*2019*	*2020*	*2021*	*2022*	*Total*
Bridger Mine						
Tons	[redacted]					
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Black Butte Mine						
Tons	[redacted]					
Btu/lb						
Mmbtus						
$/Ton						
Rail Rate $/Ton						
Total Coal Dollars						
Total Rail Dollars						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Total Deliveries						
Tons						
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
[redacted] (Black Butte Mine - Proposal D)						
Mine	*2018*	*2019*	*2020*	*2021*	*2022*	*Total*
Bridger Mine						
Tons	[redacted]					
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Black Butte Mine						
Tons						
Btu/lb						
Mmbtus						
$/Ton						
Rail Rate $/Ton						
Total Coal Dollars						
Total Rail Dollars						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Total Deliveries						
Tons						
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
VARIANCE						
	2018	*2019*	*2020*	*2021*	*2022*	*Total*
Tons	[redacted]					
Btu/lb						
Mmbtus						
Total Dollars						
$/Ton Delivered						
$/MMBtu Delivered						
Calculation of Price Savings - [redacted]						
MMBtu Delivered Variance						[redacted]
*Multiplied by [redacted] (Proposal D) MMBtus						
Price Savings						

Concurrent negotiations were held with Union Pacific Railroad for coal transportation from the Black Butte mine. The delivered costs shown in the above Table 4 includes rail transportation rates consistent with the negotiations. The estimated savings shown in the table represents PacifiCorp's share of the total savings.

Upon the expiration of the near-term 2018 contract with Black Butte mine, the pricing for Black Butte mine coal is assumed to increase at [redacted] per year.

3.2.4 Powder River Basin Coal in the Near-Term

Powder River Basin coal has a high propensity to spontaneously combust, and is the most friable coal type burned in the power industry. While major plant modifications would be required to safely and reliably receive and consume large volumes of SPRB coal at the Jim Bridger plant, the plant is likely capable of consuming SPRB coal on a limited scale without major modification to the plant's coal unloading or coal consuming infrastructure. For example, in a test burn in 2015, the plant handled and consumed 10 trains totaling 140,540 tons of SPRB coal. Based on knowledge gained from the test burn and PacifiCorp's professional judgement, plant management believes that up to [redacted] tons of SPRB coal per year might be safely and reliably consumed without major modifications to the plant. This estimate is considered to be aggressive.

PacifiCorp considered the possibility of reducing the amount of coal purchased from the Black Butte mine and purchasing a small amount, up to [redacted] tons (PacifiCorp share), from a SPRB coal mine on an annual basis. As shown in Table 5, the purchase of small volumes of SPRB coal was not the least-cost option.

For example, PacifiCorp has chosen to purchase [redacted] tons per year[3] of incremental coal from Black Butte mine under Proposal A, [redacted]. PacifiCorp has also chosen to forego the purchase of [redacted] tons per year of coal from Bridger mine (or SPRB coal) that would have been required if Black Butte mine Proposal D, [redacted], had been elected. Average costs for the [redacted] annual incremental ton variances can be derived from the proposals and mine plans outlined in Table 4 and are shown for both the Black Butte mine and Bridger mine in Table 5. The estimated average delivered cost of [redacted] tons of SPRB coal is also shown. On a delivered $/MMBtu basis, the estimated average delivered cost of [redacted] tons of SPRB coal [redacted] is [redacted] than the delivered cost of Black Butte mine's incremental coal [redacted] over the term of the proposals. In addition, the estimated delivered cost of [redacted] tons of SPRB coal [redacted] is [redacted] over the four year term than the incremental cost of coal mined at the Bridger mine [redacted].

As shown in Table 5, this relationship also holds when comparing deliveries under Black Butte mine Proposal A and Black Butte mine Proposal B, [redacted]. If Proposal B was chosen, PacifiCorp would forego the purchase of [redacted] tons of the [redacted] total incremental tons available under Black Butte mine Proposal A. On a delivered $/MMBtu basis, the estimated average delivered cost of [redacted] tons of SPRB coal [redacted] is [redacted] than the delivered cost of Black Butte mine's incremental coal [redacted] over the term of the proposals. In addition, the estimated average delivered cost of [redacted] tons of SPRB coal [redacted] is [redacted] over the four year term than the incremental cost of coal mined at the Bridger

[3] Represents PacifiCorp's share of the [redacted] differential between Proposal A and Proposal D (difference between [redacted])

mine [redacted]. The concept of PacifiCorp purchasing fewer tons from Black Butte mine and replacing that volume with a small amount, from [redacted] tons up to [redacted] tons, of SPRB coal (or coal from Bridger mine) was eliminated in the near-term based on these findings.

PacifiCorp also considered accepting Black Butte mine Proposal B, [redacted], and simultaneously [redacted] Bridger mine deliveries by [redacted] tons per year to [redacted] million tons per year, on a total mine basis. Based on data shown in Table 5, in accepting Proposal B, PacifiCorp would purchase [redacted] tons of the [redacted] total incremental tons available from Bridger mine at an [redacted] premium over the cost of purchasing the coal from Black Butte mine. As a result, PacifiCorp chose to forego the purchase of [redacted] tons from the Bridger mine at an incremental cost of [redacted] in favor of purchasing the [redacted] incremental tons from Black Butte mine at an incremental cost of [redacted].

TABLE 5

Incremental Cost For Black Butte Proposal Term					
		SPRB	**Bridger**	**Black Butte (Prop. A - Prop. D)**	**Black Butte (Prop. A - Prop. B)**
Coal	$	[redacted]			
Freight	$	[redacted]			
$/Ton	$	[redacted]			
Btu/lb		[redacted]			
$/mmBtu	$	[redacted]			[4]

3.2.5 Black Butte Mine Volume

PacifiCorp conducted a high-level review of the Lighthouse Resources Inc. Black Butte mine coal resource and reserve estimates in 2015. The study consisted of reviewing available third-party Black Butte reserve and geology documents, along with Black Butte's geology information and permitting status. At the time, based on the information reviewed, the conclusion of the review was that Black Butte mine had [redacted] million tons that could be considered economic coal reserves under the terms and conditions of the then-current contract.

For assumed Black Butte mine production in the 2018 Fuel Plan, PacifiCorp has updated these reserve estimates. The estimated reserves have been [redacted] since the date of the 2015 reserve review, and have [redacted] based on discussions with Lighthouse [redacted] As of that date, Black Butte mine claimed permitted reserves of [redacted]

[4] Consistent with Table 4, incremental prices shown are weighted over the near-term, with exception of the SPRB pricing. SPRB prices are averaged over four years with equal annual volumes.

- 2018 Fuel Plan Option D – [redacted]
- 2018 Fuel Plan Option F [redacted]
- 2018 Fuel Plan Option F – [redacted]

3.2.6 Assumed SPRB Coal Pricing

Due to the Jim Bridger plant's distance from the SPRB, roughly 550 miles by rail, the Jim Bridger plant would source SPRB coal from the mines with the highest heat content (Btu/lb.) The economics of the purchase decision would target coal originating from three mines in the SPRB, Cloud Peak Energy Resources LLC's Antelope mine, Peabody COALSALES, LLC's North Antelope Rochelle Mine and Arch Coal Sales Company Inc.'s Black Thunder mine. These mines typically sell coal on an 8,800 Btu/lb. basis as opposed to other areas of the Powder River Basin that sell 8,400 Btu/lb. or lesser heat content coals.

The Powder River Basin is the largest coal mining region in the United States. As a result, standard 8,800 Btu/lb. and 8,400 Btu/lb. Powder River Basin coal is routinely traded, indexed and forecast. Assumed SPRB coal pricing used in the 2018 Fuel Plan is based on a long-term coal forecast published by EVA in September 2017.

3.2.7 Transportation

Bridger mine coal is delivered to the plant via conveyor belt, and the cost of conveying the coal is included in the delivered coal cost. The Jim Bridger plant is also connected by a rail spur to the Union Pacific Railroad mainline track. Union Pacific Railroad has the trackage rights to the mainline and spur to the Jim Bridger plant and, as a result, the Jim Bridger plant is captive to the Union Pacific Railroad for deliveries by rail. Deliveries from all sources other than Bridger mine are assumed to be delivered by the Union Pacific Railroad.

UNION PACIFIC RAILROAD INDICATIVE PRICING

Early in 2017, PacifiCorp requested that Union Pacific Railroad provide indicative rates to aid in evaluating increased SPRB coal deliveries to the Jim Bridger plant with an estimated start-up in [redacted]. PacifiCorp requested rates for deliveries ranging from [redacted] million tons per year. To better understand potential price discounts for added volume, rates for deliveries in both PacifiCorp and Union Pacific Railroad railcars were requested at various volume levels in the [redacted] per year range.

Union Pacific Railroad provided indicative rates in June 2017. The rates applied to the volume range previously specified, from [redacted] per year up to [redacted] per year and were provided in current dollars. However, Union Pacific Railroad did not provide information on volume discounts for specific volume ranges as requested, nor did Union Pacific Railroad provide specific rates for deliveries in PacifiCorp or Union Pacific Railroad railcars. Instead, it provided an estimated freight rate for planning purposes in the range of [redacted] per net ton, which included railroad owned railcars, but excluded a fuel component and quarterly escalation.

Union Pacific Railroad contract pricing

In 2017, while negotiations took place with Black Butte mine for near-term coal supplies, near-term rail transportation negotiations were also conducted with Union Pacific Railroad. Similar to the Jim Bridger plant, the Black Butte mine is connected by a rail spur to Union Pacific Railroad's mainline track. Negotiations with Union Pacific Railroad concluded with a signed contract in February 2018. The transportation agreement includes the following key provisions as of January 1, 2018:

- Minimum volume: [redacted]
- Maximum volume: [redacted]
- Rail rates provided for shipments from:
  - Lighthouse's Black Butte mine - [redacted]
  - Wyoming's SPRB region - [redacted]
  - Westmoreland Kemmerer, LLC's Kemmerer mine located in Lincoln County, Wyoming - [redacted]
  - Peabody's Twentymile mine located in Routt County, Colorado - [redacted]
- All rates subject to escalation and fuel surcharge

Use of indicative and contract pricing

For SPRB deliveries, the lower end of the indicative rate range, [redacted] per ton, is used as of January 1, 2018, in any fueling option where more than [redacted] per year are delivered to the plant. This rate is then escalated at [redacted] (provided by IHS/Global Insights in Q3 2017) per year thereafter.

When SPRB deliveries are less than [redacted] per year, the contract rate is applied. For example, a [redacted] per ton contract rate is used as of January 1, 2018, in fueling options where only small volumes of SPRB coal is delivered to the plant. This rate is also escalated at a rate of [redacted] per year thereafter.

PacifiCorp owns 121 aluminum bottom-dump railcars with a net payload of 105 tons per car. Consistent with current operating practice for Black Butte mine deliveries, the [redacted] per ton rate is used and is escalated at a rate of [redacted] per year.

3.3 Capital

PacifiCorp selected the consulting firm Burns & McDonnell (BMcD) to perform an independent capital evaluation of the plant modifications and capital expenditures required at the Jim Bridger plant to consume volumes, up to 100%, of SPRB coal. BMcD completed a comprehensive study in June 2017. The study outlined high priority plant modifications and the estimated costs in converting the Jim Bridger plant's main fuel source to SPRB coal. The study focused on required modification to several systems including coal handling & storage, rail delivery, mechanical process/power island, electrical, substation and overhead distribution and air permitting.

The required coal handling system modifications identified engineering controls that would be needed and relied upon to reduce and mitigate coal dust throughout the coal handling system. The study emphasized the importance of having adequate wash down capability by installing and utilizing fixed pipe wash down systems in existing coal reclaim and conveyor tunnels, crusher houses, tripper bays and in the rail unloading hopper facilities. Recommendations were made on how to safely and reliably handle SPRB coal: keep areas clean, eliminate ignition sources and detect spontaneous combustion with accumulated SPRB coal dust. These safety steps are designed to protect people, equipment, and enclosures from explosions due to the dangerous spontaneous combustion tendencies of SPRB coal.

Required modifications to the rail delivery system outlined in the study indicate that the current unloading configuration is [redacted]. SPRB coal requirements at this level require the plant to receive approximately [redacted]

[redacted][5]

---

[5] PacifiCorp also engaged RungePincockMinarco to evaluate the impact from converting to SPRB coal on the Jim Bridger plant's stockpile level and configuration. This study was used to verify the findings of the Burns & McDonnell study.

[redacted].

Table 6 below shows a summary outline of BMcD's total estimated costs, [redacted], associated with the different components referenced in their report.

TABLE 6

Jim Bridger Plant - Burns & McDonnell Estimated Capital Costs			
		[redacted]	[redacted]
Coal Handling	$	[redacted]	
Coal Handling Additional	$		
Existing Conveyor Scraper Tower with Wind Fence	$		
New Loop	$		
Power Island Modifications (Unit 1-4)	$		
Power Island Modifications (Unit 1-3 Only)	$		
Pulverizer Steam Inerting (Units 1-4)	$		
Electrical	$		
T&D	$		
Air Permit	$		
TOTAL	**$**		
Investment Total w/ Land/ROW Costs	**$**		
PacifiCorp Share (Includes AFUDC, Loadings)	**$**		

4 FUEL SUPPLY MIX OF PHASE 2 FUELING OPTIONS

The fueling options evaluated during Phase 2 are referenced as 2018 Fuel Plan Options D, E and F, including several variations on those primary options as described below. Please refer to Confidential Appendix B for detailed fueling mix and pricing information for each fueling option considered. The following summaries of the fuel supply mix, including average volumes for the near-term and long-term, for each fueling option evaluated are provided below:

4.1 OPTION D

Option D

- Near-term deliveries (2018-2021)
  - Bridger mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - [redacted]
- Long-Term deliveries (2022-2037)
  - Bridger mine
    - [redacted]
    - [redacted]
    - [redacted]
    - Total Deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - [redacted]
    - [redacted]
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - SPRB
    - SPRB deliveries from [redacted]
      - Total deliveries – [redacted][6]
      - PacifiCorp deliveries – [redacted]

[6] [redacted]

4.2 OPTION D ([redacted])

Option D ([redacted]) is a slight variation on Option D and contemplates [redacted]. Option D ([redacted]) assumes that in [redacted]. Option D ([redacted]) also assumes that the required capital investment is made to allow for the safe delivery and handling of a large volume of SPRB coal at that time.

Option D ([redacted])

- Near-term deliveries (2018-2021)
  - Bridger mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - [redacted]

- Long-Term deliveries (2022-2037)
  - Bridger mine
    - [redacted]
    - [redacted]
    - [redacted]
    - Total Deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - [redacted]
    - [redacted]
  - SPRB
    - SPRB deliveries [redacted]
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]
      - Assumes plant capital (w/AFUDC and escalation) of [redacted]
        - [redacted]

4.3 Option E

Option E contemplates the closure of the Bridger mine in [redacted], as soon as practicable, and assumes [redacted] of the coal burned thereafter comes from the SPRB. This option assumes a required plant capital investment to safely and reliably deliver and consume large volumes of SPRB coal, approximately [redacted] million tons per year from [redacted]. The estimated investment is [redacted] million with AFUDC and escalation ([redacted] million PacifiCorp share) and includes a rail loop to comply with the railroad standard of unloading a unit train within six hours.

Option E

- Near-term deliveries (2018-2021)
  - Bridger mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - [redacted]

- Long-Term deliveries (2022-2037)
  - Bridger mine
    - Underground mining operations [redacted]
    - Surface mining operations [redacted]
    - Total Deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - [redacted]
    - [redacted]
  - SPRB
    - SPRB deliveries from [redacted]
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]
      - Assumes plant capital (w/AFUDC and escalation) of [redacted]
        - [redacted]

4.4 OPTION F ([redacted])

Option F ([redacted]) considers the closure of the Bridger surface mining operations in [redacted] and the avoidance of [redacted] million ([redacted] million PacifiCorp share) in development costs required to permit and mine Deadman Wash, further refining Option D.

Option F

- Near-term deliveries (2018-2021)
  - Bridger mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - [redacted]

- Long-Term deliveries (2022-2037)
  - Bridger mine
    - [redacted]
    - Total Deliveries – [redacted]
  - Black Butte mine
    - [redacted]
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - For 2018-2037 time period
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]
  - SPRB
    - SPRB deliveries from [redacted]
      - [redacted]
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]

4.5 Option F [redacted])

Option F ([redacted]) is a variation of Option F ([redacted]). The primary difference is that this scenario is based on a Bridger mine plan delivering [redacted] million tons per year in the near-term and assumes Black Butte mine Proposal D, the [redacted] million tons per year proposal, is chosen in the near-term as well.

Option F ([redacted])

- Near-term deliveries (2018-2021)
  - Bridger mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]

- Long-Term deliveries (2022-2037)
  - Bridger mine
    - [redacted]
    - Total Deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - [redacted]
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - For 2018-2037 time period
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]
  - SPRB
    - SPRB deliveries [redacted]
      - [redacted]
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]

4.6 OPTION F ([redacted])

Option F ([redacted]) is a slight variation on Option F and contemplates no longer purchasing Black Butte mine coal after the near-term Coal Supply Agreement ends. Option F ([redacted]) assumes that [redacted] coal replaces Black Butte mine coal in [redacted]. Option F ([redacted]) also assumes that the required capital investment is made to allow for the safe delivery and handling of a [redacted].

Option F ([redacted])

- Near-term deliveries (2018-2021)
  - Bridger mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - Total deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
    - [redacted]

- Long-Term deliveries (2022-2037)
  - Bridger mine
    - [redacted]
    - [redacted]
    - [redacted]
    - Total Deliveries – [redacted]
    - PacifiCorp deliveries – [redacted]
  - Black Butte mine
    - [redacted]
    - [redacted]
  - SPRB
    - SPRB deliveries from [redacted]
      - Total deliveries – [redacted]
      - PacifiCorp deliveries – [redacted]
      - [redacted]
        - Peak deliveries will occur from 2029 through 2032 – [redacted]

5 PVRR ANALYSIS & RESULTS

Table 7 below shows the results of a PVRR analysis for each fueling option in the 2018 Fuel Plan. The PVRR analysis represents a present value revenue requirement analysis of the total delivered fuel costs and the estimated capital requirements for both the Jim Bridger plant and the Bridger mine, discounted by PacifiCorp's weighted average cost of capital. A total dollar PVRR variance or differential has also been calculated for every fueling option comparing the total PVRR dollar for each fueling option against Option [redacted]. Also included in Table 7 is a financial ranking from 1 to 6 for each of the six fueling options. The Table shows Option [redacted] is ranked [redacted], and Option [redacted] is ranked number [redacted]. The other fueling options fall between these two options. Additional discussion on risk assessment for each fueling option is shown below.

TABLE 7

Jim Bridger Plant Fueling Evaluation (2018-2037) - PacifiCorp Share								
PVRR Summary PAC Portion	PVRR (000's)	PVRR Differential (from lowest $)	Financial Ranking (low to high)	Percent Change (%)	Risk Ranking (low to high)	Project Ranking (Weighted - Financial 60%, Risk, 40%)	Plant Capital (w/AFUDC and escalation, 000's)	Bridger Coal Capital (2018-LOM, escalated, 000's)
[redacted]								

Table 8 presents a risk table for each option and outlines the specific categories that have been considered in the risk evaluation analysis.

TABLE 8

Jim Bridger Plant Fueling Risk Evaluation (2018-2037)							
Options	Risk Ranking (low to high)	Composite Project Risk Score	Incremental Capital	Coal Market	Power Market Volatility	Jim Bridger Plant Environmental Compliance	Deadman Wash Lease Permitting
[redacted]							

The different categories making up the defined risk profile include (1) incremental capital – the risks associated with the total costs of incremental capital expenditures related to each fueling option, (2) coal market – risks associated with adequate coal supplies, as well as coal & transportation price escalation, (3) power market volatility – risks associated with power market price volatility related to changing natural gas prices, the impacts of renewable energy sources impacting GRID dispatch, all which could result in reduced coal consumption, (4) environmental compliance – risks associated with new environmental regulations that could reduce coal generation at the Jim Bridger plant, and (5) Deadman Wash permitting – risks associated with being able to permit the Deadman Wash coal reserve tract in the estimated number of years that would allow the Bridger mine to access the Deadman Wash coal reserve tract and achieve the projected mine cost savings.

For each fueling option under each risk category, a number 1, 2, or 3 has been assigned. Number 1 is designated as "most favorable and low risk." number 2 is "less favorable and moderate risk," and number 3 is "least favorable and high risk." The summation of the assigned risk number for each category for each fueling option, results in an overall "composite project risk" score.

As shown in Table 8, the fueling option with the highest composite risk score is fueling Option [redacted] with a score of [redacted]. Option [redacted] requires incremental capital associated with both the Deadman Wash coal tract as well as new plant capital to support future SPRB coal deliveries. As such, there is added risk for Option [redacted] associated with the capital projects meeting projected cost estimates. Furthermore, there is additional risk associated with the permitting of the Deadman Wash coal reserves in sufficient time which allows for the projected coal production and deliveries from the Bridger mine to be realized. An additional sensitivity was run that determined that for each year of delay in the Deadman Wash permit, the total PVRR amount calculated for Option [redacted] increases by approximately [redacted]. This further closes the PVRR differential gap between Option [redacted] and the other fueling options. The fuel option with the lowest composite risk score, or most favorable score, is Option [redacted]. Under this option there is no incremental capital required and there is very low risk associated with the coal supplies. The other five fueling options have a composite risk score that falls between Option [redacted] and Option [redacted].

All six fuel options are ranked on ascending order from 1 to 6 based upon their composite risk score. Option [redacted] has the most favorable risk option score of [redacted], while Option [redacted] has the worst or highest ranking of [redacted].

From the financial and risk rankings, an overall project ranking has been determined for each fueling option. The overall project weighting is the result of assigning a weighting of [redacted] to the financial ranking and [redacted] to the risk ranking.

As seen in Table 7, in spite of Option [redacted] having the financial ranking of [redacted], it has a risk ranking of [redacted]. This results in an overall project ranking of [redacted]. Option [redacted], has a financial ranking of [redacted], but has the lowest risk ranking of [redacted]. With the weighting between financial and risk rankings, Option [redacted] has the best overall project ranking and is the preferred fueling option. The fueling option with the worst overall project ranking of [redacted] is Option [redacted]. The remaining fueling options are ranked in between Option [redacted] and Option [redacted].[7]

[7] Additional sensitivity analysis was performed on two options. (1) Plant capital was reduced in Option [redacted] for the assumed removal of the rail loop. This change resulted in a reduction to the PVRR differential for Option [redacted] as the savings in capital were offset by increased transportation costs resulting from increased coal unloading times. (2) Option [redacted] was evaluated assuming that approximately [redacted] was purchased in years requiring high volumes of [redacted], deliveries in excess of [redacted]. The [redacted] purchases of roughly [redacted], reduced Black Butte mine volumes in those years. Due to the higher delivered fuel cost of the [redacted], this change resulted in an increase to the PVRR differential for Option [redacted].

6 CONCLUSION

Over the past two years, PacifiCorp has developed a long-term fueling strategy for the Jim Bridger plant to align with the Company's IRP and respond to changing fuel requirements due to market conditions. Mine plans have been run, evaluated and reviewed for the Bridger mine. The various mine options have provided information and direction in determining the optimal total tonnage mix at the Bridger mine for both the underground mine and the surface mine. Different mine closure dates for both the underground mine and the surface mining operations have been considered and evaluated.

Over many months, numerous discussions and negotiations occurred with Lighthouse and the Union Pacific Railroad to develop new near-term coal and transportation agreements. Through these negotiations, new contract rates from different coal regions were obtained. Additionally, long-term indicative rail rates from mines located in the SPRB were provided by the Union Pacific Railroad for coal deliveries to the plant.

In addition to the estimated future coal and transportation rates provided, PacifiCorp also contracted for two consulting studies which provided important information in the PVRR analysis. These two studies were requested to better understand the overall fueling impacts, capital requirements and estimated costs related to a full or partial SPRB fuel switch at the plant. BMcD, a reputable engineering consulting company, completed a comprehensive fuel impact study in June 2017. The study outlined the relevant issues and total estimated costs that would be required to undertake a SPRB coal conversion at the plant.

After considering all of the factors influencing this long-term fueling strategy, six different fueling options were developed and evaluated. Based upon the results of the detailed PVRR analysis, which was further enhanced by utilizing a risk profile, Option [redacted] is the current least-cost, least-risk option and the strategy PacifiCorp is currently pursuing which includes the following:

- [redacted]
-
-
-
-
-

While the current analyses shows Option [redacted] as the least-cost, least-risk option, Option [redacted] is the lowest cost option and will continue to be analyzed. PacifiCorp will continue to evaluate the best fueling option for the Jim Bridger plant taking into consideration both cost and risk of the different options and will change the long-term fuel plan as necessary to provide the least-cost, least-risk long-term fuel supply for the Jim Bridger plant. Furthermore, both Options [redacted] and Option [redacted], allow PacifiCorp to [redacted]

This strategy allows PacifiCorp and the plant to maintain significant fuel supply flexibility related to future decisions impacting the plant's generation and potential unit closures. [redacted]

Confidential Appendix A

Jim Bridger Plant - Generation Summary
Generation Forecast
All Participant Shares - In Millions

Plan Comparison

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Dec-'15 Long Term Fuel Plan																					
MMBtu's Required	[redacted]																				
Forecasted Generation (MWh)																					
2018 Fuel Plan																					
MMBtu's Required																					
Forecasted Generation (MWh)																					
Variance																					
MMBtu's Required																					
Forecasted Generation (MWh)																					
Percent Change (%)																					

REDACTED

Sierra Club/118
Burgess/32

CONFIDENTIAL APPENDIX B-OPTION D

Jim Bridger Plant - Option D
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company	[redacted]																				
Tons																					
MMBTUs																					
Dollars																					
$/Ton																					
$/MMBTU																					
Black Butte																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Regional Coal																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Powder River Basin																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Received																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

REDACTED

CONFIDENTIAL APPENDIX B-OPTION D ([redacted])

Jim Bridger Plant - Option D ([redacted])
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company																					
Tons	[redacted]																				
MMBTUs																					
Dollars																					
$/Ton																					
$/MMBTU																					
Black Butte																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Regional Coal																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Powder River Basin																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Received																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

REDACTED

CONFIDENTIAL APPENDIX B-OPTION E

Jim Bridger Plant - Option E
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company	[redacted]																				
Tons																					
MMBTUs																					
Dollars																					
$/Ton																					
$/MMBTU																					
Black Butte																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Regional Coal																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Powder River Basin																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Received																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

CONFIDENTIAL APPENDIX B-OPTION F [redacted]

Jim Bridger Plant - Option F ([redacted]
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company	[redacted]																				
Tons																					
MMBTUs																					
Dollars																					
$/Ton																					
$/MMBTU																					
Black Butte																					
Tons																					
MMBTU																					
Dollars																					
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Regional Coal																					
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Powder River Basin																					
Tons																					
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Dollars																					
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Total Coal Received																					
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Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

REDACTED

CONFIDENTIAL APPENDIX B-OPTION F ([redacted])

Jim Bridger Plant - Option F ([redacted])
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company																					
Tons	[redacted]																				
MMBTUs																					
Dollars																					
$/Ton																					
$/MMBTU																					
Black Butte																					
Tons																					
MMBTU																					
Dollars																					
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Powder River Basin																					
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Total Coal Received																					
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Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

REDACTED

Sierra Club/118
Burgess/37

CONFIDENTIAL APPENDIX B-OPTION F ([redacted])

Jim Bridger Plant - Option F ([redacted])
Coal Received and Consumed
PacifiCorp Share - (in millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	Total
Bridger Coal Company	[redacted]																				
Tons																					
MMBTUs																					
Dollars																					
$/Ton																					
$/MMBTU																					
Black Butte																					
Tons																					
MMBTU																					
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Regional Coal																					
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Powder River Basin																					
Tons																					
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Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Received																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					
Total Coal Consumed																					
Tons																					
MMBTU																					
Dollars																					
$/Ton																					
$/MMBTU																					

CONFIDENTIAL APPENDIX C-RISK RANKING

Jim Bridger Plant Fueling Risk Evaluation (2018-2037)							
Options	Risk Ranking (low to high)	Composite Project Risk Score	Incremental Capital	Coal Market	Power Market Volatility	Jim Bridger Plant Environmental Compliance	Deadman Wash Lease Permitting

[redacted]

Docket No. UE 390
Exhibit Sierra Club/119
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

EXHIBIT SIERRA CLUB/119

Exhibit Accompanying the Opening Testimony of Ed Burgess

Corrected Supplemental Direct Testimony of David G. Webb in California Public Utilities Commission Proceeding A.20-08-002

Application No. 20-08-002
Exhibit No. PAC/600 Rev 1
Witness David G. Webb

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

PACIFICORP

Errata to the Supplemental Testimony of David G. Webb

Net Power Costs

[PUBLIC VERSION]

March 1, 2021

Q. Are you the same David G. Webb who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company)?

A. Yes.

I. Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. In its approval of the Company's 2020 Energy Cost Adjustment Clause (ECAC) rates in Decision (D.) 20-12-004, the Public Utilities Commission of California (Commission) ordered PacifiCorp to provide supplementary testimony in this proceeding that:

1. Includes information on the marginal fuel cost assumed for each coal plant, the specific coal plants where adjustments were made to align forecasted generation with minimum take provisions, and the magnitude of adjustments made;
2. Includes three Generation and Regulation Initiative Decision Tools (GRID) model runs: one that depicts the net power costs (NPC) when adjustments are made to the Dispatch Tier to meet minimum take provisions; one that depicts the NPC when the Dispatch Tier is based purely on marginal costs; and one that depicts the NPC when average fuel costs are utilized to forecast unit dispatch; and
3. To aid parties in the identification and review of new coal supply contracts, address the prudence of any coal supply after coal supply after the record was submitted in the ECAC in the filing from the previous year. The Commission also stated that at a minimum, the supplemental testimony address the generation forecast used to negotiate the new coal supply agreement; whether the contract includes a minimum take provision, and if so, a comparison of the volume of the minimum take provision to the forecasted generation at the associated coal generation plant; and, a general description of how the coal contract

compares with any previous coal supply contract(s) being replaced.[1]

In my supplemental testimony, I address the first two items above. In the supplemental testimony submitted by Mr. Dana M. Ralston, he addresses item 3 concerning new coal supply agreements.

II. Requested Information Regarding Marginal Fuel Costs

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I provide information on the marginal or incremental fuel cost for each coal plant, the specific coal plants where adjustments were made to align forecasted generation with minimum take provisions, and the magnitude of adjustments made.

Q. Please summarize the marginal or incremental fuel cost for each coal plant and the adjustments made to align with the required minimum take provisions.

A. As seen in Confidential Figure 1 below, five coal plants—Colstrip, Craig, Dave Johnston, Naughton and Wyodak—out of the nine coal plants did not need to have adjustments made in order to satisfy the required minimum take volume. The coal plants where adjustments were made—Hayden, Hunter, Huntington, and Jim Bridger—and the magnitude of those adjustments are also reflected in Confidential Figure 1 below.

[1] *In the Matter of the Application of PacifiCorp (U901E) for Approval of its 2020 Energy Cost Adjustment Clause and Greenhouse Gas-Related Forecast and Reconciliation of Costs and Revenue,* D.20-12-004 (Dec 7, 2020).

Confidential Figure 1

Variance Between Initial Incremental Price and Final Base Studies

2021 ECAC Plant	Required Minimum (MMBtu)	Initial Incremental Price ($/MMBtu)	Initial Incremental Study Volume (MMBtu)	Final Incremental Price ($/MMBtu)	Final Base Study Volume (MMBtu)	Incremental vs. Final Variance ($/MMBtu)	Incremental vs. Final Variance (MMBtu)
Colstrip	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Craig	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dave Johnston	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hayden	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hunter	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Huntington	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Jim Bridger	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Naughton	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wyodak	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]		[redacted]		[redacted]		[redacted]

Q. What is the purpose of the adjustments made to incremental costs in GRID?

A. The adjustments to incremental prices in the base study reduce overall NPC for customers by recognizing that the volumes in a take-or-pay or liquidated damages volume tier have an incremental cost lower than those used in the purely incremental coal price scenario study. Ideally, PacifiCorp's GRID model would have both differentiated and volume restricted volume tiers (the first tier to incorporate volumes in a take-or-pay price tier with an incremental cost of $0, the second to represent the next incremental volume and price combination, and so forth), but GRID was not designed to model and therefore cannot recognize multiple incremental price tiers. For that reason, the Company adjusts incremental prices to ensure that minimum purchase obligations are satisfied.

Q. Which incremental prices were adjusted in the final base study and why?

A. There were four plants that had prices adjusted during the iterative coal cost process, but only three had a material effect. Fuel consumption at the Huntington plant and Jim Bridger plant was substantially beneath their minimum requirements in the first iteration of the base study (approximately ~~19~~ 32 and ~~16~~ 17 percent, respectively), and those prices were revised downward in order to clear the minimum contractual purchase obligations. In doing so, the Hunter plant, which had initially cleared its minimum purchase requirement, had a portion of its own generation displaced, which then required another iterative adjustment to the incremental prices at Hunter in order that it too would satisfy all contractual obligations. The final price change was a small downward adjustment in Hayden incremental prices. Adjustments were limited to plants where such a change was required in order to respect contractual minimums, and each plant with an adjusted price now has a fuel consumption forecast within 3% of the contractual requirements (that is to say, prices were not adjusted to a such degree that the GRID model produced unreasonable results).

Q. Please explain why this iterative modeling process is needed.

A. As described in the rebuttal testimony of Michael G. Wilding in the Company's 2020 ECAC filing,[2] fuel in a take-or-pay tier is essentially a previously incurred (or "sunk") cost, so declining to make use of those volumes and utilizing other energy sources to satisfy the Company's load obligation serves only to increase NPC for customers. In the case of the final base study compared to the purely incremental coal price scenario, the incremental cost of not employing the iterative modeling process would be approximately $[redacted] million on a total-company basis, as indicated by the study executed in order to quantify the impact of the Company's iterative coal modeling process.

III. Requested Additional GRID Model Runs

Q. Has PacifiCorp performed the three model runs as directed by the Commission in

[2] Application 19-08-002, Exhibit No. PAC/600

their 2020 ECAC Decision?

A. Yes. PacifiCorp was directed by the Commission to include three GRID model runs: (1) a GRID model run that depicts the net power costs (NPC) when adjustments are made to the Dispatch Tier to meet minimum take provisions; (2) a GRID model run that depicts the NPC when the Dispatch Tier is based purely on marginal costs; and (3) a GRID model run that depicts the NPC when average fuel costs are utilized to forecast unit dispatch.[3] The first NPC model run that the Commission directed PacifiCorp to provide depicts the NPC when adjustments are made to the Dispatch Tier to meet minimum take provisions. This run is the base study GRID run that supports the NPC report submitted with my direct testimony as Exhibit PAC/104 for the 2021 calendar year test period. I have included the GRID model run that supports Exhibit PAC/104 in my workpapers. The GRID model runs using purely marginal costs and using average fuel costs are also provided as workpapers to my supplemental testimony.

Q. Please summarize the results of the comparison study using unadjusted marginal or unadjusted incremental prices.

A. The impact to the 2021 test period is summarized in Confidential Figure 2 below. The overall impact to system costs is an increase of approximately $[redacted] million.

[3] D.20-12-004 (Dec 7, 2020) pp. 16-17.

Confidential Figure 2

Net Power Cost Reconciliation

	($ millions)	$/MWh
2021 ECAC Final Base Study	**$1,403**	**$23.61**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	[redacted]	
Purchased Power Expense	[redacted]	
Coal Fuel Expense	[redacted]	
Natural Gas Fuel Expense	[redacted]	
Wheeling and Other Expense	[redacted]	
Total Increase/(Decrease) to NPC	[redacted]	
Incremental Coal Price Scenario	[redacted]	[redacted]

Q. Please summarize the drivers of the increase in NPC as a result of using unadjusted incremental pricing.

A. The primary driver of the increase in NPC is the increase in natural gas fuel expense of [redacted] million, as natural gas fired generation offset a decrease in coal fired generation. Coal fuel expense also increased by [redacted] million even though coal fired generation declined by 1.~~5~~9 million MWh, owing to the assessment of liquidated damages and take-or-pay dollar amounts. Other changes included a small decrease in purchased power expense.

Q. Was another study executed in order to show the impact of forecasting NPC using average coal prices?

A. Yes. The results are presented in Confidential Figure 3 below.

Confidential Figure 3

Net Power Cost Reconciliation

	($ millions)	$/MWh
2021 ECAC Final Base Study	**$1,403**	**$23.61**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	[redacted]	
Purchased Power Expense	[redacted]	
Coal Fuel Expense	[redacted]	
Natural Gas Fuel Expense	[redacted]	
Wheeling and Other Expense	[redacted]	
Total Increase/(Decrease) to NPC	[redacted]	
Average Coal Price Scenario	[redacted]	[redacted]

Q. Please describe the drivers behind the change in NPC as a result of the use of average fuel costs?

A. NPC increased by approximately $[redacted] million on a total-company basis, driven by increases in purchased power expense, coal fuel expense, natural gas fuel expense, and offset slightly by increases in wholesale sales revenue.

Q. Why did NPC increase in the average coal price scenario compared to the final ECAC base study?

A. Even though coal generation fell by approximately 15 percent as a result of the change to dispatch tier prices, coal fuel expense increased as a result of the contractual purchase volume minimums remaining unsatisfied in the final generation forecast. In addition, power purchases and natural gas generation both increased to offset the decline in coal generation.

Q. Does this warrant comparison to a previously executed study in the same manner that the unadjusted incremental price study did above?

A. No. The Company views the decision to use incremental prices as a fundamental of economic analysis. The comparison and discussion of changes in incremental prices above is warranted because during the preparation of the NPC forecast that accompanies an ECAC filing, the analyst tasked with generating the forecast will begin with the unadjusted incremental costs and make fairly narrow adjustments aimed at bringing the forecasted fuel consumption into alignment with the contractual minimum purchase obligations. Under no circumstances would the company consider beginning with average costs and adjusting from there.

Q. What is the primary conclusion from the analysis presented in this testimony?

A. The Company continues to forecast NPC in a cost-minimizing way in order to ensure that the interests of customers are respected. If the Company were to follow a convention of using average fuel costs or unadjusted incremental costs, the NPC forecast would increase, to the detriment of California customers.

Q. Does that conclude your testimony?

A. Yes.

3219/025/X224597.v1

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

EXHIBIT SIERRA CLUB/120

Exhibit Accompanying the Opening Testimony of Ed Burgess

PacifiCorp's Response to Sierra Club Data Request 8.7 in California Public Utilities Commission Proceeding A.20-08-002

A.20-08-002/ PacifiCorp
March 1, 2021
Sierra Club Data Request 8.7

Sierra Club Data Request 8.7

CONFIDENTIAL REQUEST - Please refer to "CONFIDENTIAL - Supplemental Webb Attachment – Avg Costing Tier Analysis (X224135).xlsx". Jim Bridger shows a **[CONFIDENTIAL BEGINS]** [redacted] **CONFIDENTIAL ENDS]** in its output when the model run is based on average prices. However, costs **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** only by **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**.

(a) Please explain why.

(b) Please explain whether the **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** in coal consumption is assumed to be from the CSA with Black Butte Company or the one with Bridger Coal Company. Please provide any rationale for this assumption.

(c) If the answer in (b) is that the **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** in coal consumption is assumed to impact the CSA with BBC **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**:

   i. Please explain whether the **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** in coal burn expenses for the Jim Bridger plant would differ if the assumption in (b) changed to **[CONFIDENTIAL BEGINS]** [redacted] **CONFIDENTIAL ENDS]**.

   ii. Please provide the total difference in the NPC between the final and average cost runs **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**.

Confidential Response to Sierra Club Data Request 8.7

Referencing confidential work paper "CONFIDENTIAL - Supplemental Webb Attachment – Avg Costing Tier Analysis (X224135).xlsx" from the Supplemental Testimony of Company witness, David G. Webb, the Company responds as follows:

(a) The output for the Jim Bridger plant shows a **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** in output, but only a **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** in costs because take-or-pay and/or liquidated damages provisions raise the average prices on a per million British thermal units (MMBtu) basis such that the reduction in cost was not commensurate with the reduction in generation.

(b) The reduction in coal consumption is assumed to be from the coal supply agreement (CSA) with Black Butte Coal Company. The Black Butte contract minimum in 2021 is **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** tons. Jim Bridger plant coal consumption decreased from **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** tons in the 2021 energy cost adjustment clause (ECAC) filing to **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** tons in the average coal cost analysis. If no coal reduction was assumed from Black Butte, Bridger Coal's production would be limited to **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** tons. Bridger Coal's underground mine exclusively is scheduled to produce **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]** tons in 2021. At Bridger Coal's underground mine, a "steady rate of retreat" is required in longwall mining because it reduces prolonged abutment loading on the weak strata which can result in deterioration of the roof strata, roof failures and convergence on the longwall face. Abutment loading can be defined as the weight of waste material or rock over a longwall face being transferred to the front abutment (solid coal ahead of the longwall) and rear abutment (settled packs behind the face or gob) areas. Convergence can be defined as a narrowing of distance between the floor and roof which occurs as the longwall retreats. Abutment loading can result in caving of the roof strata above the longwall shields which inundates the area between and in front of the longwall shields with waste material. This negatively impacts longwall productivity rates, coal quality, operating costs and can create unsafe working conditions.

This analysis is based on options available to the company currently. To fully evaluate the impact of dispatching the Jim Bridger plant on an average cost basis, the company would need to develop and complete a long-term fueling evaluation. The company does not dispatch thermal resources on an average cost basis. This concept will result in higher fuel costs paid by customers because dispatch decisions will not be based on the cost of the next available megawatt-hour (MWh), but rather on the average cost of all MWh.

(c) Please refer to the Company's response to subpart (b) above.

Confidential information is provided subject to the terms and conditions of the non-disclosure agreement in this proceeding between PacifiCorp and Sierra Club.

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EXHIBIT SIERRA CLUB/121

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to Sierra Club Data Request 2.3

This exhibit is confidential pursuant to Protective Order 16-128 and is provided under separate cover.

PUBLIC UTILITY COMMISSION OF OREGON

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EXHIBIT SIERRA CLUB/122

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to Sierra Club Data Request 2.7

This exhibit is confidential pursuant to Protective Order 16-128 and is provided under separate cover.

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EXHIBIT SIERRA CLUB/123

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to Sierra Club Data Request 2.22

This exhibit is confidential pursuant to Protective Order 16-128 and is provided in Excel format.

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EXHIBIT SIERRA CLUB/124

Exhibit Accompanying the Opening Testimony of Ed Burgess

PacifiCorp Response to Sierra Club Data Request 3.1 in California Public Utilities Commission Proceeding A.20-08-002

A.20-08-002/ PacifiCorp
November 16, 2020
Sierra Club Data Request 3.1

Sierra Club Data Request 3.1

Please refer to PacifiCorp responses to SC 1.16 and SC 1.28, which describe the use of the PCI optimization model and the iOpt model.

(a) Please describe the difference in how PacifiCorp uses these two models during system operations.

(b) Please confirm whether PCI is the primary model used by PacifiCorp to determine unit commitment decisions. Please explain what role, if any, iOpt plays in determining unit commitment.

(c) Please explain whether unit commitment status is a direct output of the PCI model, or whether there are subsequent decision points to determine unit commitment.

(d) Please explain whether either of these models includes any of the following and whether they are outputs generated by the model, or input assumptions:

i. Nodal pricing estimates
ii. Hub or zonal pricing estimates
iii. System lambda

Response to Sierra Club Data Request 3.1

(a) The Company does not utilize the Power Costs Incorporated (PCI) or iOpt optimization models during system operations.

(b) The Company's energy market traders are responsible for unit commitment decisions. The PCI and iOpt models provide an output that is the result of optimizing system obligations with Company resources. Due to expected variations between input forecasts and actual real-time operating conditions, market traders use the modeled results as a guide when making decisions on dispatching Company assets. Note: The iOpt model was retired by the Company on October 6, 2020.

(c) Please refer to the Company's response to subpart (b) of this data request above.

(d) Please refer to the Company's responses to subparts i. through iii. below:

i. Nodal pricing estimates are neither an input nor output to the PCI and iOpt models.

ii. Hub price estimates are an input to both the PCI and iOpt models.

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iii. The Company assumes “system lambda” to mean the marginal cost of serving energy. Based on the foregoing assumption, the Company responds as follows:

The output of the PCI model includes an estimated marginal cost of serving energy. The model’s results are part of the inputs used in (serves as a guide to) making decisions on dispatching Company assets, but do not reflect actual system dispatch decisions due to variations between input forecasts and actual real-time operating conditions.

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EXHIBIT SIERRA CLUB/125

Exhibit Accompanying the Opening Testimony of Ed Burgess

PacifiCorp Response to Sierra Club Data Request 5.1 in California Public Utilities Commission Proceeding A.20-08-002

A.20-08-002/ PacifiCorp
January 4, 2021
Sierra Club Data Request 5.1

Sierra Club Data Request 5.1

Please refer to Confidential Attachment SC 1.28 which provides the iOpt model run output for April 3, 2019.

(a) Please explain what is represented in each of the workbook tabs (e.g. “ST System Prior”, “ST System Current”, etc).

(b) Please explain how the iOpt model chooses which units to operate on PacifiCorp’s system and how it chooses the level of dispatch.

(c) Please provide the assumed marginal energy cost assumptions (e.g. $/MWh) used in iOpt for each of PacifiCorp’s coal units.

(d) On the “ST System Current” tab and “ST System Prior” tab, please provide the source or derivation of the Market Price values starting on line 410.

(e) Please provide the Market Price location that is associated with each of PacifiCorp’s coal generation units.

(f) Please explain whether any of the iOpt model runs include any “must run” or “minimum burn” constraints for PacifiCorp’s coal units. If so, please provide the dates and times of these designations for each unit.

Response to Sierra Club Data Request 5.1

Referencing the Company’s response to Sierra Club Data Request 1.28, specifically Confidential Attachment SC 1.28, which provided the available archived information from iOpt for April 3, 2019.the Company responds as follows:

(a) Please refer to the below overview description of each tab in the iOpt output for April 3, 2019:

“ST” stands for “short-term” time period which, in the April 3, 2019 example, covers the balance of month April and prompt month of May. The green highlighted tabs labeled with system show the short and long system positions by region and by node for the current days, the day prior, and the day on day changes to system positions as optimized by the iOpt model. The red highlighted tabs labeled with the word “reserves” contains the net reserves position by region broken out by reserve requirements and reserve credits and reserve type, also shown for prior day, current day, and day on day changes. The un-highlighted tabs, “ST Reserve Stack” and “ST Fuel Consumption” show the current day’s reserve position by region and unit and fuel burn values, and a calculated heat rate, by unit for the balance of month and the

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prompt month. The blue highlighted tabs labeled with the word "Generators" show the unit generator balances as optimized by iOpt for the prior day current day and day on day changes. The "generators" tabs have calculated the balance of the unit by taking in to account any dispatch volumes and volumes held for reserves against that unit's initial capacity. The capacities summary tab at the end shows the transmission capacities across various locations by peak type and season for that time period.

(b) Based on the inputs given, the iOpt model calculates a suggested position for traders to review early next morning and is used as a starting reference or guide to inform traders of possible dispatch decisions. The iOpt model calculates this physical system position using forecasted retail loads, market prices, resource characteristics, system constraints, and reserve holding requirements at a point in time the model is being run. The iOpt model selects units in order of increasing cost, based on the inputs at the time the model was ran, to meet system obligations.

(c) The iOpt model calculates a suggested position using coal and gas fuel costs, heat rate curves, and market price inputs. Marginal energy costs are an output of the model. The archived iOpt results provide the heat rate and the fuel cost inputs and associated marginal energy cost outputs from that night's iOpt run.

(d) The market prices are provided as an input to the iOpt model. The market prices used in the April 3, 2019 results were developed from observed on-peak and off-peak power market activity. In order to calculate hourly prices needed for the iOpt model, internal proprietary hourly scalars are used to extrapolate on-peak and off-peak prices to 24 hourly values per day.

(e) Please refer to Confidential Attachment SC 5.1-1, which provides a list of the coal units and their market price locations according to the locations listed in iOpt model output results.

(f) The iOpt model incorporated the physical constraints of the generators which can include must run conditions. The Company accounts for must run or minimum run constraints when there is a system need to do so. For example, a unit may require running at a minimum level in order to perform scheduled maintenance activities and therefore would be included in the iOpt model at that point in time. These conditions are reviewed and updated daily by the resource planning group which is responsible for communicating with plant managers to provide outage, minimum run, or must run conditions and provides that information to energy supply management. Please refer to Confidential Attachment SC 5.1-2, which provides a copy of the upcoming outages and derates (UOD) report for April 3, 2019 showing the conditions that were in place for that day's iOpt model simulation.

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January 4, 2021
Sierra Club Data Request 5.1

The confidential attachments are provided subject to the terms and conditions of the non-disclosure agreement in this proceeding between PacifiCorp and Sierra Club.

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EXHIBIT SIERRA CLUB/126

Exhibit Accompanying the Opening Testimony of Ed Burgess

PacifiCorp Response to Sierra Club Data Request 7.1 in
California Public Utilities Commission Proceeding A.20-08-002

A.20-08-002/ PacifiCorp
February 19, 2021
Sierra Club Data Request 7.1

Sierra Club Data Request 7.1

Please refer to Confidential Attachment SC 1.28 which provides the iOpt model run output for April 3, 2019.

(a) In the ST Reserve Stack tab, please explain what the Fuel Cost and Run Cost values (columns H and I) represent, and what units these costs are expressed in (e.g. $/MMBTU, $/MWh, etc).

(b) For the Jim Bridger units, please explain whether the fuel cost values shown are intended to represent coal from the Bridger Coal Company, the Black Butte mine, or some other fuel source.

Response to Sierra Club Data Request 7.1

Referencing the Company's response to Sierra Club Data Request 1.28, specifically Confidential Attachment SC 1.28, which provided a copy of the available archived information from iOpt for April 3, 2019, the Company responds as follows:

(a) The fuel cost inputs for coal represent the incremental cost of coal delivered to each plant in forecasted dollars per million British thermal unit ($/MMBtu). Fuel cost inputs for natural gas represent the natural gas cost at burner tip prices for each natural gas plant based on applicable natural gas forward price curves forecasted in $/MMBtu.

Run costs are iOpt-calculated outputs expressed in dollars per megawatt-hour ($/MWh) based on the fuel cost in the balance of month period, and the maximum heat rate for the specific unit.

(b) With reference to the provided April 3, 2019 iOpt archived information, the fuel cost used for the Jim Bridger units was the plants' incremental cost from the Bridger Coal Company coal mine supplemental coal supply agreement.

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CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Excerpt from Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 1.32

This exhibit is confidential pursuant to Protective Order 16-128 and is provided under separate cover.

June 9, 2021

Via Electronic Filing

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

Re: Docket No. UE 390-Sierra Club Opening Testimony and Exhibits of Ed Burgess

Enclosed please find the Opening Testimony and Exhibits of Ed Burgess (Sierra Club/100-127) on Behalf of Sierra Club in Docket No. UE 390. Confidential and highly confidential versions of the documents herein will be served in accordance with OAR 860-001-0070(3) and the Commission’s Covid-19 Response outlined in Order 20-088 on all eligible party representatives electronically via encrypted password protected ZIP folders

If you have any questions or require any additional information, please do not hesitate to contact me.

Respectfully submitted,

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

In the Matter of PACIFICORP d/b/a PACIFIC POWER, 2022 Transition Adjustment Mechanism	Docket UE 390

CERTIFICATE OF SERVICE

I hereby certify that on this 9th day of June, 2021, I have served the confidential and highly confidential portions of the Opening Testimony and Exhibits of Ed Burgess pursuant to Protective Order No. 16-128 and 21-086 respectively upon all eligible party representatives electronically via encrypted password protected ZIP folders.

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Dated this 9th day of June, 2021 at Redwood City, CA.

/s/ Ana Boyd

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