July 30, 2021

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Re: Docket No. UE 390-Sierra Club Rebuttal Testimony and Exhibits of Ed Burgess

Enclosed please find the Rebuttal Testimony and Exhibits of Ed Burgess (Sierra Club/200-203) on Behalf of Sierra Club in Docket No. UE 390. The confidential version 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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Docket No. UE 390
Exhibit SC/200
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

Rebuttal Testimony of Ed Burgess

On Behalf of
Sierra Club

Public Version

July 30, 2021

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1. Introduction

Q. Are you the same Ed Burgess who provided opening testimony in this docket on behalf of Sierra Club?

A. Yes, I am.

Q. What is the purpose of your testimony?

A. My testimony responds to the issues raised in the reply testimonies of PacifiCorp d/b/a Pacific Power ("PacifiCorp" or "Company") witnesses Douglas R. Staples, Dana M. Ralston, Daniel J. MacNeil, and Seth Schwartz. I continue to address the prudence of the Company's proposed 2022 Net Power Costs ("NPC"), particularly regarding coal fuel expenses. Specifically, I respond to the following issues:

- First, I respond to various issues regarding Jim Bridger coal fuel, particularly the Bridger Coal Company ("BCC" or "Bridger mine") costs.
- Second, I respond to several issues PacifiCorp raised regarding new coal contract terms.
- Third, I respond to various issues regarding PacifiCorp's dispatch practices, including economic cycling.
- Finally, I respond to several other issues including: dispatch versus costing tier prices, a recent decision by the California Public Utilities Commission, PacifiCorp's open positions, grid reliability, and other parties' positions in this case.

The fact that I have not addressed each and every one of the issues that PacifiCorp's reply testimonies raised in response to my opening testimony does not mean that I agree with the Company's characterization of my assessment.

2. BCC Costs

A. Fixed Costs

Q. In your opening testimony, you cited PacifiCorp's response to Sierra Club Data Request 2.5(c),[1] which specifies that there are approximately $[redacted] in "wholly identifiable fixed costs" for BCC in 2022. Is that correct?

A. Yes. My testimony also points out that some of the cost items included in this estimate are not entirely fixed, such as final reclamation.

Q. Despite its response to Sierra Club's data request, did PacifiCorp subsequently dispute the notion that $[redacted] is a reasonable approximation of the fixed costs at BCC?

A. Yes. In reply testimony, PacifiCorp suggested that I omitted certain fixed costs that were not specifically quantified in PacifiCorp's response.[2] According to PacifiCorp, these additional fixed costs are "embedded in labor and benefits, materials/supplies, electricity, outside services and other miscellaneous costs."[3]

Q. Did you intentionally omit any significant fixed cost items from the analysis provided in your opening testimony, as PacifiCorp alleges?

A. No. Because PacifiCorp was unable to provide any numerical estimate for the "embedded" fixed costs of the items in question, I presumed the fixed cost component of these other items was *de minimus*. Moreover, certain items PacifiCorp identified such as "materials/supplies" and "electricity" are obviously a direct function of the volume of

[1] Sierra Club/112 at Burgess/6.
[2] PAC/400 at Staples/64:16-65:6.
[3] *Id.* at Staples/64:20-21 (quoting Sierra Club/112 at Burgess/6).

coal extracted and it is only logical to treat them as variable costs with no fixed component.

Q. Did PacifiCorp provide any additional evidence in its reply testimony, or through discovery, specifying what portion of these other cost categories are fixed costs?

A. No. If PacifiCorp truly believed that there were significant fixed costs in excess of $[redacted], I would have expected them to provide supporting evidence of this fact in their reply testimony. However, they did not. Even when specifically asked to identify the fixed portion of these costs through discovery, PacifiCorp was unable to do so.[4] Furthermore, PacifiCorp's response to SC 5.5(b) shows that no costs associated with labor and benefits, materials/supplies, electricity, outside services or other miscellaneous costs were incurred prior to the Company's 2022 TAM filing.

Q. Didn't PacifiCorp's reply testimony point out that approximately $[redacted] in projected labor costs could be considered fixed,[5] thus increasing the projected fixed costs at BCC from $[redacted] to $[redacted]?

A. Yes. However, in doing so PacifiCorp completely ignored my point that these assumedly "fixed" labor costs might be substantially reduced prior to 2022 if a lower coal volume need was projected. I agree that a certain amount of contracted labor costs might be considered fixed as of January 1, 2022. However, PacifiCorp provided no evidence that it would be unable to revise its labor costs well ahead of 2022. As PacifiCorp stated in response to SC 2.5(c), "The relationship between fixed and variable costs change

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[4] PacifiCorp Response to Sierra Club Data Request 5.5(a) (attached as exhibit Sierra Club/201).
[5] PAC/400 at Staples/64:9-10.

depending on the time period of the review."[6] PacifiCorp argued that the labor costs are fixed but only if viewed "from the prism of a one year test period."[7] However, because we have not yet entered the one-year test period in question, it is premature to call these costs fixed. Additionally, to the extent that PacifiCorp intends to redirect some of its mining activities to reclamation in future years, some amount of ongoing labor costs may already be accounted for in the portion of the $[redacted] in fixed costs claimed by PacifiCorp that it has attributed to reclamation.

Q. Have you been able to verify whether any of these labor costs, or other costs PacifiCorp asserts as "fixed" for 2022 BCC production, were incurred prior to the 2022 TAM filing?

A. Yes. In its response to SC 5.5(b), PacifiCorp did not identify any labor costs among those costs incurred prior to the 2022 TAM filing. Furthermore, PacifiCorp did not produce any contracts or agreements for labor or any other fixed cost categories associated with 2022 BCC production that were executed prior to the 2022 TAM filing.[8] Finally, PacifiCorp identified the typical length of such agreements, but was unable to specify how far in advance they are normally executed.[9] This leads me to believe that there were no additional labor costs or any other costs associated with 2022 BCC production that could be considered "fixed" at the time of the 2022 TAM filing (outside of those identified in 5.5(b)). As such, I maintain the conclusion provided in my opening testimony that the true 2022 fixed costs for BCC coal are approximately $[redacted] or less.

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[6] Sierra Club/112 at Burgess/6.
[7] *Id.* at Burgess/6.
[8] Sierra Club/201, PacifiCorp Response to Sierra Club Data Request 5.5(c).
[9] Sierra Club/201, Confidential PacifiCorp Response to Sierra Club Data Request 5.5(d).

Q. Were there any other key points you made on this issue that PacifiCorp ignored?

A. Yes. PacifiCorp ignored my point that a large portion of the estimated fixed costs would still be recovered even under the average cost scenario (such as that provided in response to SC 2.22 and discussed in my opening testimony) due to the remaining coal volume still consumed. Therefore, this portion would not need to be included in any post-modeling adjustments (*i.e.*, "reaveraging"). This underscores the fact that the amount of BCC fixed costs that may be at risk for under-recovery is likely far less than the $[redacted] total (and may in fact be zero). I address this further in Section 2-E below.

Q. Did PacifiCorp provide any general insight on how to differentiate between fixed and variable costs at BCC?

A. Yes. According to Mr. Schwartz, "The proper approach is to prepare complete mine plans and budgets for different levels of operations."[10]

Q. Did PacifiCorp's application in this case include a comparison of the 2022 base plan to a mine plan that reflects a significantly reduced level of operation at BCC?

A. No. In fact, the only other levels of operation considered by PacifiCorp were *increased* levels of production rather than any decreased levels.[11]

Q. What do you conclude from this fact?

A. It may be possible for PacifiCorp to significantly reduce the amount of fixed costs at BCC (and total customer costs) in 2022 if a lower production volume were pursued.

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[10] PAC/500 at Schwartz/19:8-9.
[11] Confidential workpaper accompanying the Direct Testimony of Dana Ralston (PAC/200) "BCC - 2022 TAM Incremental Analysis (Final).xlsx".

However, PacifiCorp has chosen not to complete the analysis it asserts is necessary for the Commission to evaluate this possibility.

Q. Does PacifiCorp agree that it would be possible to plan in advance for a significantly reduced production volume at BCC?

A. Yes. For example, Mr. Ralston's reply testimony included the following:

> Q. If a significant reduction in Jim Bridger plant generation were known in advance of critical decisions points, how would PacifiCorp respond to those diminished fueling needs?
>
> A. Within reasonable limits, PacifiCorp, in conjunction with its partner, would alter BCC mine plans by adjusting shifts worked at the surface mine, redirect mining activities from coal production to reclamation when feasible, flex coal inventory levels, and seek to align future external contract volumes with the reduced generation forecast mitigating Jim Bridger plant fuel supply risks and costs.[12]

Q. When was the last time PacifiCorp actually completed an analysis of alternative mine plans for Jim Bridger?

A. According to Mr. Ralston, this occurred in 2019, as part of an update provided in the 2020 TAM proceeding.[13]

Q. Is it surprising to you that PacifiCorp did not complete additional analyses of its BCC mine plan in its 2021 and 2022 TAM applications that included a significantly reduced level of production?

A. Yes. As I mentioned in my opening testimony, PacifiCorp has known about the high costs of BCC coal for several years. If these costs, including the significant amount of future fixed costs PacifiCorp alleges, could be avoided, then PacifiCorp customers could stand to benefit to the tune of tens of millions of dollars *every year*. Thus, PacifiCorp

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[12] PAC/600 at Ralston/49:17-50:3.
[13] *Id.* at Ralston/42:17-19.

should be closely evaluating mine plans in each TAM proceeding to identify opportunities to substantially reduce production volumes and associated costs in future years, including fixed costs. I would also expect PacifiCorp would be eager to share the detailed results of these analyses with the Commission as evidence that it is striving to minimize BCC fuel costs. However, it appears that PacifiCorp has taken none of these actions, which reinforces the recommendation in my opening testimony that the Commission order PacifiCorp to provide a report in future TAM proceedings documenting the steps it has taken to reduce costs at the Bridger mine.

Q. Can you explain what you mean by "substantially reduce production" at BCC?

A. Yes. By this I mean a reduction on par with the Generation and Regulation Initiative Decision ("GRID") model run using average fuel costs at Jim Bridger as provided in SC 2.22, which reduced output at the Jim Bridger plant by about [redacted] percent relative to the TAM base case.[14]

Q. Do you have any other general observations on the relative fueling costs for BCC coal, including fixed costs?

A. Yes. It is noteworthy that most other coal suppliers in PacifiCorp's portfolio (including non-Powder River Basin suppliers) have managed to keep their fuel prices—which also reflect their own fixed costs—substantially lower than BCC.[15] Moreover, even though the BCC costs included in the TAM are high relative to other suppliers, they only reflect a fraction of the total BCC costs charged to PacifiCorp customers because additional

[14] Sierra Club/100 at Burgess/65 (Confidential Table 10) (citing ORTAM22 NPC CONF (Webb) at "Coal Summary" tab; Sierra Club/123, Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 2.22).
[15] *See e.g.*, Sierra Club/100 at Burgess/13 (Confidential Table 2).

BCC fixed costs are included in base rates separate from the TAM. This calls into question PacifiCorp's overall cost management practices at BCC, particularly given the fact that this is an affiliate mine that is essentially immune from any competitive market pressures that would otherwise serve as a mechanism to contain costs.

B. Reporting

Q. What did PacifiCorp testify regarding your recommendations for additional reporting on BCC coal costs in future TAMs?

A. Mr. Staples testified that BCC coal costs "are properly accounted for in the GRID model and any further discussion of the prudence of these costs should be addressed in PacifiCorp's long-term mine plan or IRP processes."[16]

Q. Do you agree with this assessment?

A. No. In my opinion, PacifiCorp has not been very forthcoming in providing information about its coal costs, and repeatedly refuses to provide unredacted electronic copies of its coal contracts and affiliate mine plans to Commissions and intervenors (subject to appropriate confidentiality treatment). While PacifiCorp has allowed limited viewing sessions of the underlying contracts and mine plans, this arrangement is far from ideal for conducting a rigorous assessment of the contract terms and has presented hurdles to my own analysis, as the viewing sessions typically involve review of multiple contracts and only limited note taking is permitted. Frankly, I'm surprised that PacifiCorp would object to additional transparency measures to make sure that the Commission understands the costs associated with BCC coal, particularly because PacifiCorp owns the Bridger mine,

[16] PAC/400 at Staples/72:17-19.

and, therefore, any concerns over competitively confidential information that might be raised by third party suppliers would not apply in this particular case.

Q. Do you agree that the only proper venues to address BCC costs are "in PacifiCorp's long-term mine plan or IRP processes"?

A. No. First, just because these other processes address BCC costs does not mean that BCC costs cannot be reported in the TAM, where substantial BCC costs are recovered. Second, because the IRP does not authorize fuel cost recovery, the IRP process is thus inappropriate to provide adequate oversight over BCC fueling cost. Finally, according to Mr. Ralston, PacifiCorp's fueling strategy for Jim Bridger has historically been addressed in the TAM. More specifically: "Issues regarding PacifiCorp's fueling strategy for the Jim Bridger plant have been raised multiple times over the years, including in the dockets UE 264 (2014 TAM), UE 307 (2017 TAM), UE 323 (2018 TAM), UE 339 (2019 TAM), and UE 356 (2020 TAM)."[17] Thus, I think it is wholly appropriate for the Commission to evaluate PacifiCorp's long-term mine plan in the present 2022 TAM proceeding.

C. __Quantity__

Q. Did PacifiCorp testify regarding the quantity of coal that the BCC mine must produce?

A. Yes. According to Mr. Schwartz, the BCC mine operations must be capable of producing between [redacted] and [redacted] tons per year at the Bridger surface mine to "support the output of the Jim Bridger power plant[,]"[18] based on the level of Jim Bridger operations over the past five years.

[17] PAC/600 at Ralston/42:11-14.
[18] PAC/500 at Schwartz/20:6-9.

Q. Do you agree that BCC must be equipped at all times to produce at historical levels?

A. No. This would only be true if it were expected that Jim Bridger would provide electricity, on an annual MWh basis, that is comparable to historic levels. In contrast, it may be economically beneficial to PacifiCorp's customers if the Company reduced the total output of Jim Bridger on an annual MWh basis, such that it produces below historical levels.

Q. In your opening testimony, you suggested that it might be beneficial not to renew the Black Butte coal supply agreement ("CSA"). Did PacifiCorp raise concerns about the quantity of coal under this scenario?

A. Yes, according to PacifiCorp, "BCC could not deliver the Jim Bridger plant's required coal by itself. Given that Black Butte coal is lower price than the alternative, it is unclear why Sierra Club believes that the Company may not need to renew the Black Butte contract."[19]

Q. Do you agree?

A. No. Under the average price GRID run produced in SC 2.22, for example, the Bridger plant would only require [redacted] MMBtu of fuel.[20] This is substantially less than what BCC has historically produced, which is closer to [redacted] MMBtu.[21] As such, there should be no concern with the quantity of coal under a scenario where the Black Butte supply were removed. With respect to the lower price of Black Butte coal, I agree that it may be preferable to consider an option where BCC were to shut down production

[19] PAC/600 at Ralston/48:16-49:3.
[20] Sierra Club/123.
[21] Confidential workpaper accompanying the Direct Testimony of Dana Ralston (PAC/200) "Cost Comparison.xlsx"; Confidential Attachment to PacifiCorp Response to Sierra Club Data Request 2.6 (attached as Exhibit Sierra Club/202).

instead of Black Butte. However, that appears to be a practical impossibility due to the fixed cost concerns PacifiCorp has repeatedly raised.

D. <u>Self-Dealing and BCC Supplemental Coal</u>

Q. In your opening testimony, you pointed out the possibility that PacifiCorp could be gaming the pricing of BCC supplemental coal to its own advantage. How did PacifiCorp respond?

A. PacifiCorp's reply simply stated that "[m]any decades ago, the Commission consolidated BCC on PacifiCorp's balance sheet to avoid any possibility of self-dealing and to ensure that BCC coal supply was priced on an actual cost (not market) basis. Sierra Club's position ignores this important regulatory context."[22]

Q. Do you agree that this 39-year-old decision absolves PacifiCorp of any potential self-dealing in 2022?

A. Not at all. First, the decision PacifiCorp cites includes no reference to BCC supplemental coal, the GRID model, the TAM, and many other relevant factors that did not exist in 1982.[23] Second, just because the Commission required PacifiCorp to price BCC coal on an actual cost basis does not eliminate the potential for gaming by PacifiCorp. Because PacifiCorp owns the BCC mine and earns a regulated return on investments in the mine, it has an inherent incentive to increase mine production, even on an "actual cost (not market) basis." Meanwhile, PacifiCorp still has discretion over a variety of issues that could inflate BCC coal projections, including:

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[22] PAC/400 at Staples/66:4-7 (citation omitted).
[23] *Re Pacific Power & Light Company*, Docket No. UF 3779, Order No. 82-606 (Aug.18, 1982).

- Which mine plans to study and/or select in its long-term fueling strategy;
- Whether to pursue only the BCC base quantity or the BCC base and supplemental quantities; and
- Whether the "marginal" cost of coal assumed in GRID reflects just the supplemental quantity or both the supplement and the base quantity (which is the lion's share of total coal purchases from the Bridger mine).

Relying on one provision of a single decision from nearly four decades ago does not demonstrate that the BCC regulatory construct is fully protecting customers. I believe it may be time for a reexamination, including evaluating potential self-dealing issues associated with supplemental coal quantity and pricing.

i. *Basic economic principles*

Q. Mr. Staples states that using average costs, instead of incremental costs, is contrary to basic economic principles.[24] Is this accurate?

A. Mr. Staples' statement is not entirely accurate. First, it is worth noting that the Company has acknowledged that the dispatch tier prices used in GRID are not necessarily equal to the incremental costs of generation, but rather are set at the price point needed to ensure that a unit's coal consumption exceeds the minimum take requirement.[25] Thus, the Company's own dispatch practice does not exactly follow marginal costs as it would normally be defined using economic principles. Second, standard economic principles dictate that the use of marginal cost (or incremental cost) pricing is optimal *only* under specific conditions that are not satisfied in PacifiCorp's case. More specifically, in a

[24] PAC/400 at Staples/63:11-13.
[25] PAC/100 at Webb/30:2-7.

competitive market, a seller's optimal price is indeed the marginal cost but *only* if the marginal cost is above the average cost. If the marginal cost is below the average, as is the case with certain take or pay provisions and PacifiCorp's supplemental pricing at BCC, then every unit of goods sold at the marginal cost will result in economic losses. Selling at a loss for a limited period of time to recover some of the sunk costs might be a viable option, but in the long run the seller should either shut down operations to avoid additional losses, reduce the portion of costs that are fixed, or increase the price towards the average. This means that a pre-existing contract signed several years ago might justify selling at a loss to ensure minimum volume consumption, but this can only be justified for a limited period of time, and only if there is no opportunity to revise the underlying contract. Signing CSAs knowing that they will be selling power at a loss (*i.e.*, dispatch tier is less than costing tier) is not only imprudent, but contrary to basic economic principles. The practice of selling power below average cost would be unsustainable for the Company if not for the existence of the TAM and PCAM, which disconnect cost recovery from market competition. In this case, ratepayers subsidize the Company's uneconomic operations.

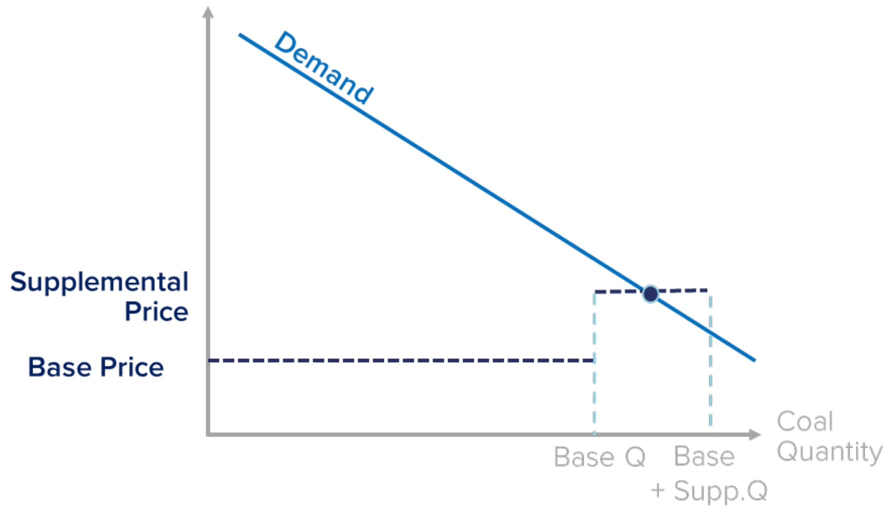
Q. Can you further illustrate why PacifiCorp's use of supplemental pricing at BCC is not consistent with basic economic principles?

A. Yes. Below are two graphs illustrating two different potential supply curves for coal fuel. In the first graph, the supply curve indicates an upward sloping marginal cost (*i.e.*, supply), which would be typical of most commodities purchased in a competitive marketplace. The base quantity is available at a specific price, while the supplemental quantity is available at a higher price. According to economic principles, optimizing dispatch in this case would result in dispatching at a price equal to the incremental cost (*i.e.*, the supplemental price). In the second graph, however, the marginal cost curve reflects a situation more similar to PacifiCorp's BCC costs, which is distorted from the more typical market shown in the first graph. In the BCC case, the supplemental quantity being available at a significantly lower price than the base quantity leads to an atypical, inverted, and downward-sloping supply curve. Thus, dispatching the unit based on the fuel's supplemental price results in overgeneration from coal that is not aligned with the equilibrium that would be achieved if the base price were used. More importantly, it results in ratepayers paying more for electricity costs. This is because any electricity generated from the base quantity of coal above Point A in the chart could have been supplied from a more economic resource. Although ratepayers benefit from subsequent consumption of lower priced coal (supplemental quantity), this happens only after the Company has consumed a significant amount of the base quantity at an economic loss. Thus, to gain the "full benefits of mine ownership" that come from using the BCC supplemental quantity price, as Company witness Mr. Staples claims,[26] ratepayers end up paying significantly more than they should, resulting in a net effect that is actually detrimental to them.

[26] PAC/400 at Staples/66:14.

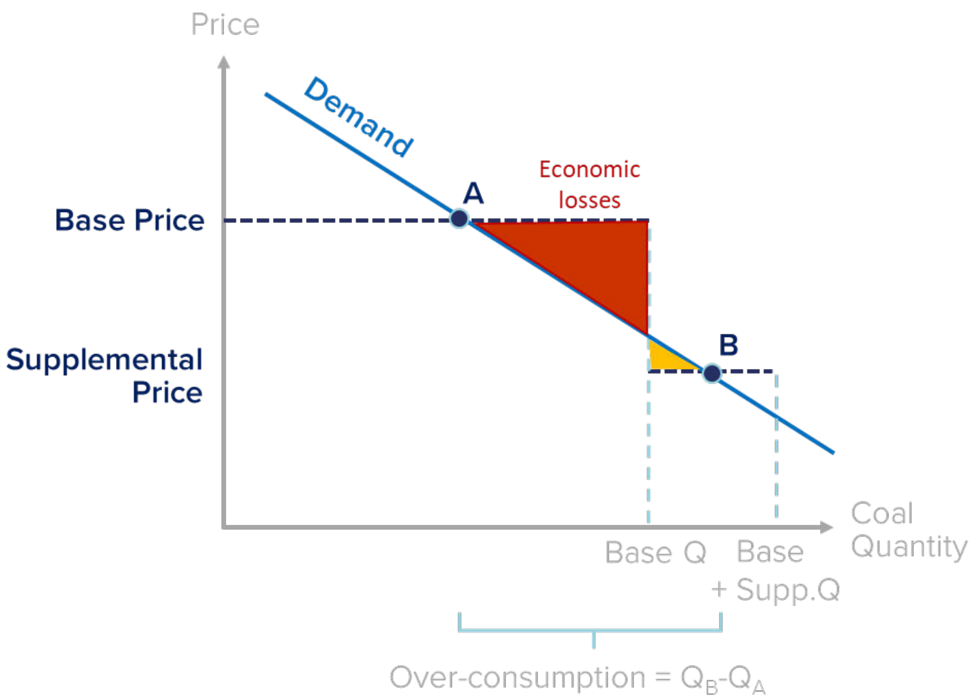
Table 1: Coal Fuel Supply Curves

Case 1: Optimal Price and Quantity in a Competitive Market with a Normal Supply Curve



Optimal coal consumption under appropriate pricing (with increasing MC)

Case 2: Optimal Price and Quantity with a Distorted Supply Curve like BCC



A: Optimal coal consumption under appropriate pricing
B: Consumption when dispatch cost is based on supplemental pricing

Q. Can you further explain why PacifiCorp's use of a supplemental price for BCC results in higher costs?

A. Yes. As depicted on the second graph above, if fuel costs at Jim Bridger were priced correctly, then coal generation from this unit should stop at point A. But because PacifiCorp uses supplemental pricing (with decreasing marginal cost), coal consumption is forecasted at point B. This means that for every ton of base coal quantity that is consumed above point A, ratepayers pay more than they should because other generation units could supply electricity at a lower cost. This results in economic losses to ratepayers which are depicted by the red triangle (*i.e.*, coal cost paid minus the cost of the available alternative). On the other hand, the "benefit" of the incremental pricing, shown by the smaller yellow triangle, comes from the cost of the supplemental quantity being lower than the cost of some alternatives. However, to reach that benefit, ratepayers have already paid a significantly higher cost. This concept is confirmed in PacifiCorp's GRID runs using average cost whereby the coal consumed at Jim Bridger falls well below the base quantity.

ii. <u>Use of supplemental quantity pricing before the base quantity is exhausted.</u>

Q. Based on the economic principles described above, you testified that it was inappropriate for PacifiCorp to assume the BCC supplemental quantity pricing before the base quantity was exhausted. Correct?

A. Yes.

Q. PacifiCorp disagreed with your testimony. Did you find PacifiCorp's reply to this convincing?

A. Not at all.

Q. What specifically did PacifiCorp say regarding your recommendation that PacifiCorp's fuel cost assumption for Jim Bridger in GRID—which is equal to the BCC supplemental price—be replaced with a higher cost fuel source?

A. Mr. Staples stated that "GRID would select alternative resources with a cost lower than BCC's base plan but higher than BCC's incremental cost because the model would not recognize the availability of BCC's lower cost incremental production."[27]

Q. Do you agree that this is problematic?

A. No. Contrary to PacifiCorp's assertion that this will result in higher costs, this scenario can and will lead to lower costs. This is because, as explained above, the base quantity is significantly more expensive than the supplemental quantity. Thus, it is generally favorable for the model to select an alternative resource that can displace coal from BCC, even if the alternative is more expensive on a per unit basis than the BCC supplemental coal supply.

Q. Can you provide an illustrative example of this?

A. Yes. Please see the table below showing how displacing BCC coal using an alternative resource higher in cost than the BCC supplemental price but lower than the BCC base price can lead to lower overall costs.

[27] PAC/400 at Staples/66:11-13.

Confidential Table 2: BCC Coal Cost Comparison

Resource	Price ($/MMBtu)	Quantity (PAC's 2022 TAM, MMBtu)	Quantity (50% BCC Replacement Scenario, MMBtu)
BCC Base	[redacted]	[redacted]	[redacted]
BCC Supplemental	[redacted]	[redacted]	0
Alternative Resource	[redacted]	0	[redacted]
Total Quantity		[redacted]	[redacted]
Total Cost		[redacted]	[redacted]

In the table above, the second column shows the price of different resource options. A hypothetical alternative resource with a price of $[redacted]/MMBtu is assumed to be able to displace BCC coal. This price represents the [redacted], which I believe is a reasonable proxy for a potential replacement resource. The third column shows the quantity of coal consumed under PacifiCorp's initial 2022 TAM projection. The fourth column shows the result of displacing 50 percent of BCC coal with the alternative resource. As is readily apparent, the resulting cost is lower, despite the fact that the alternative resource was more expensive on a per unit basis than the BCC supplemental coal.

E. <u>NPC Adjustment</u>

Q. Your opening testimony included the following recommendation: "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."[28] Do you continue to have the same recommendation?

A. Yes, I do.

Q. Did your opening testimony provide an example of the potential cost savings to PacifiCorp's customers that would result from a revised NPC that removed inappropriate fuel costs forecasted for Jim Bridger?

A. Yes. The GRID run I mentioned above and in my opening testimony (provided by PacifiCorp in SC 2.22) shows NPC cost savings of approximately $[redacted].[29]

Q. Based on this example, is there any action that the Commission could take immediately, without requiring PacifiCorp to conduct further analysis, to revise the NPC component of the proposed 2022 TAM to account for inappropriate coal fuel costs forecasted for the Jim Bridger plant?

A. Yes. The Commission could reduce the 2022 NPC recoverable through the TAM by $[redacted] (or about $[redacted] Oregon allocated). This reflects the results of the GRID run PacifiCorp performed using the actual costing tier values (*i.e.*, average cost) for Jim Bridger's fuel inputs. I recommend that the Commission take this action.

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[28] Sierra Club/100 at Burgess/2:6-9.
[29] Sierra Club/123.

Q. Please explain why a $[redacted] NPC reduction is appropriate.

A. $[redacted] is equal to the reduction in NPC under the GRID run conducted by PacifiCorp in response to SC 2.22.[30] This scenario is nearly identical to the 2022 TAM model run in PacifiCorp's initial filing, except for one important change, which was to adjust the input assumption for Jim Bridger fuel costs. In making this change, the $[redacted]/MMBtu costing tier price[31] (*i.e.* average cost) was substituted for the marginal fuel cost of $[redacted]/MMBtu[32] that PacifiCorp had initially (and incorrectly) assumed, which is based on the BCC supplemental price.[33]

Q. Why is the average cost appropriate to use for Jim Bridger?

A. The average cost of $[redacted]/MMBtu is numerically closer to the BCC base coal price of $[redacted]/MMBtu.[34] As explained in my opening testimony, the BCC base is more reflective of the true marginal cost of fuel at Jim Bridger than the BCC supplemental cost that PacifiCorp initially assumed. Because the TAM is forward looking, the ongoing marginal cost is the correct lens to evaluate a future year's fuel costs (*e.g.*, 2022). This is especially true because PacifiCorp owns the Bridger mine and can make plans in advance for a substantially reduced BCC coal volume. Under this scenario, there is no need for the BCC supplemental coal quantity, and thus each incremental MWh generated consumes BCC base coal (rather than supplemental). Consumption from the BCC Base and Black

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[30] Sierra Club/123 (SC 2.22 model run); Confidential workpaper accompanying the Direct Testimony of David Webb (PAC/100) "ORTAM22 NPC CONF.xlsm" (2022 TAM model run).
[31] Sierra Club/106 at Burgess/1.
[32] *Id.*
[33] Confidential workpaper accompanying the Direct Testimony of Dana Ralston (PAC/200) "BRIDGER.xlsx" at "Detail" tab.
[34] *Id.*

Butte coal sources are substantially reduced or eliminated, and overall Jim Bridger fuel costs (and total NPC) are also significantly reduced.

Q. In your opening testimony, you stated that there are certain fixed costs at BCC that might warrant a [redacted] percent reduction in the marginal fuel costs. Is this accounted for in the GRID run conducted by PacifiCorp in response to SC 2.22?

A. Yes. PacifiCorp's assumed 2022 coal prices at Jim Bridger are as follows:[35]

$[redacted]/MMBtu for BCC Base

$[redacted]/MMBtu for BCC Supplemental

$[redacted]/MMBtu for Black Butte (currently uncontracted)

Thus, the use of the average (costing tier) fuel price ($[redacted]/MMBtu) is already more than [redacted] percent below the BCC base price.

Q. Does this still allow PacifiCorp to recover fixed costs at BCC?

A. Yes. The use of the Jim Bridger average price ($[redacted]/MMBtu) is actually somewhat conservative in the sense that it reflects a price more than [redacted] percent below the true marginal fuel cost (*i.e.,* BCC base coal, $[redacted]/MMBtu). At this price, the remaining quantity of coal consumed should still be able to support recovery of fixed costs at BCC, assuming production at the BCC and Black Butte mines are appropriately scaled down in 2022 (including any newly incurred fixed costs).

[35] *Id.*

Q. Since your opening testimony, has PacifiCorp provided any new information on costs they have already incurred (including fixed costs) that are attributable to 2022 BCC production?

A. Yes. According to SC 5.5(b), these costs amount to $[redacted], of which only $[redacted] match the categories that PacifiCorp has identified as "wholly identifiable fixed costs."[36]

Q. How do these sunk costs compare to the 2022 Jim Bridger fuel expenditures projected in the GRID run using the average (costing tier) fuel price?

A. They are substantially lower. The GRID run projected coal fuel expenditures at Jim Bridger in 2022 of $[redacted][37] which should be more than sufficient to recover the $[redacted] in costs that PacifiCorp has already incurred, leaving $[redacted] to cover any remaining costs of scaled down BCC production and other obligations at Jim Bridger.

Q. Do you believe $[redacted] is sufficient to cover all of the relevant cost categories for Jim Bridger fuel in 2022, including the previously incurred costs, scaled down BCC production, and other obligations?

A. Yes. The table below provides a breakdown of the coal fuel-related costs that I estimate would be incurred at Jim Bridger for 2022 under this scenario. Notably the total costs, including fixed costs, are less than $[redacted].

[36] Sierra Club/112 at Burgess/6.
[37] Sierra Club/123.

Confidential Table 3: 2022 Jim Bridger Coal Costs under Average Cost Scenario (SC 2.22 GRID Run)

Cost	MMBtus Delivered	Cost ($ millions, PAC share)	Type	Notes/Source
Black Butte Coal ([redacted] deferred tons)	[redacted]	[redacted]	Fixed (take or pay)	Ralston's BRIDGER workpaper
BCC Coal	[redacted]	[redacted]		MMBtu equal to [redacted]% of initial TAM estimate[38]
Labor and Benefits		[redacted]	*Variable*	[redacted]*% of initial TAM estimate provided in Ralston's Cost Comparison workpaper*[39]
Materials & Supplies		[redacted]	*Variable*	*See above*
Other Controllable Costs			*Variable*	*See above*
Royalties and Taxes (excl. property tax)		[redacted]	*Variable*	*See above*
Coal Inventory & Deferred Longwall		[redacted]	*Variable (already incurred)*	*Sierra Club 5.5(b)*
Depreciation & Depletion		[redacted]	*Fixed (already incurred)*	*Sierra Club 5.5(b)*
Other Fixed Costs		[redacted]	*Fixed*	*Sierra Club 2.5(c) Management Fee, Insurance, Property Tax (excludes reclamation)*
Total	[redacted]	[redacted]		Total MMBtu equal to GRID run w/ average cost. Total cost is less than $[redacted] projected in GRID run.

[38] I have assumed a [redacted] percent reduction in total BCC production for the following reasons. First, the total coal burn for Jim Bridger under the SC 2.22 GRID run is [redacted] MMBtu. I assumed that [redacted] MMBtu would be fulfilled by the deferred Black Butte tonnage, leaving [redacted] MMBtu to be supplied by BCC, which is [redacted] percent of the total BCC volume that PacifiCorp assumed in their initial 2022 forecast.

[39] Each variable cost category listed in this table is scaled down to [redacted] percent of PacifiCorp's initial estimate in accordance with the reduced BCC production. Cost categories identified as fixed or already incurred were not scaled down.

Q. Are there any BCC coal cost categories included in PacifiCorp's initial 2022 projections that are not included in the table above?

A. Yes. There are no BCC supplemental coal costs included because the volume of projected coal consumption in this scenario did not exceed the 2022 BCC base quantity. Additionally, the table above does not include any final reclamation costs. As explained in my opening testimony, I believe PacifiCorp has mischaracterized this item as an entirely fixed cost and may also be inflating these costs for other reasons. For these reasons, I have excluded it from the table. However, even if final reclamation costs were included at the full amount PacifiCorp specified in SC 2.5(c) (*i.e.*, approximately $[redacted]), the total Jim Bridger fuel costs would only increase to $[redacted]. This is very close to the $[redacted] in Jim Bridger expenses projected in the costing tier (average price) GRID run. If the full amount of PacifiCorp's expected reclamation costs are included, that would equate to a total NPC reduction of about $[redacted] ($[redacted] Oregon allocated) rather than $[redacted] ($[redacted] Oregon allocated).

Q. What is your final recommendation based on this?

A. I still recommend that the Commission order PacifiCorp to use an appropriate marginal cost for the Jim Bridger plant in its GRID model and adjust NPC accordingly. Because the Jim Bridger average cost is a reasonable approximation of the plant's true marginal cost, the Commission should reduce the authorized NPC recovered through the TAM by $[redacted] based on the GRID model run using Jim Bridger's average price, provided by PacifiCorp in response to SC 2.22. In the alternative, if the Commission believes that PacifiCorp's estimated final reclamation costs of $[redacted] for 2022 are prudent, then I recommend that the NPC be reduced by $[redacted].

3. Coal Contract Terms

A. Prudence of Minimum Takes

Q. How did PacifiCorp characterize your testimony regarding the prudence evaluation of coal contracts with minimum take provisions?

A. PacifiCorp stated that "[i]t is unreasonable to simply ignore these very real costs, based solely on Sierra Club's supposition that when GRID shows that a minimum take provision is not met, it must be a result of an imprudent coal supply agreement."[40]

Q. Do you believe this is a fair characterization?

A. No. I did not argue that 100 percent of the costs of any contract (especially existing contracts) should be considered imprudent when the associated plant cannot economically meet its minimum take requirement. However, I do believe that entering into a new contract for a plant that has a demonstrable risk of not meeting the minimum take quantity could be deemed imprudent and that customers should not be responsible for any penalty payments resulting from PacifiCorp's decision to enter into a new coal supply agreement with minimum take requirements that it cannot economically meet.

Q. Did you recommend any specific remedies to protect PacifiCorp customers against risky (and potentially imprudent) contracting decisions?

A. Yes. I recommended several specific remedies, including two that I reiterate here. First, I recommended that the minimum take quantities for new contracts should not be set too high. In doing so, I suggested that 50 percent of the total projected volume was a reasonable level that would reduce risk to customers. If a contract minimum take exceeds this level then it should be subject to further scrutiny. However, I did not explicitly state

[40] PAC/400 at Staples/57:3-5.

that a contract in excess of 50 percent would be automatically deemed imprudent; rather, PacifiCorp must provide additional justification for why the Commission should approve a coal supply agreement with minimum take requirements in excess of 50 percent of anticipated burn. Second, I recommended that any penalties incurred by failing to meet the minimum take quantity should not be automatically passed through to customers. I believe this is warranted because it ensures that PacifiCorp is subject to appropriate competitive pressures when negotiating its fuel supply agreements. In essence, PacifiCorp would be exposed to the same risk factors that a merchant generator would be exposed to.

Q. Regarding the second remedy (*i.e.*, PacifiCorp pays any penalties for not meeting minimum take quantities), do you believe that an unfair risk would be placed on PacifiCorp?

A. No. In fact, multiple PacifiCorp witnesses testified that there is little risk of not meeting the minimum take quantities. For example, with respect to the new Hunter CSAs, Mr. Schwartz states that "[t]here is little risk that the minimum take provisions will exceed the coal burn over the next three years and the commitment is certainly not imprudent."[41] Similarly, Mr. Ralston states that "it is extremely unlikely that the Company has entered minimum take obligations that will be below the burn requirements at the Hunter plant."[42] As such, PacifiCorp should have no problem accepting the cost responsibility of any shortfall payments associated with this contract.

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[41] PAC/500 at Schwartz/36:4-6.
[42] PAC/600 at Ralston/41:3-4.

Q. Did PacifiCorp call into question the need for additional scrutiny on CSAs that exceed 50 percent of the anticipated coal burn?

A. Yes. In particular, Mr. Schwartz stated: "In all my experience, I have never encountered a coal buyer willing to have as little as 50 percent of its projected burn under contract for the upcoming year."[43]

Q. How do you respond?

A. While Mr. Schwartz undoubtedly has a long history working for the coal industry, he may be less familiar with some of the more recent trends that point towards increasing shares of coal being delivered through spot contracts or shorter term lengths, rather than long-term arrangements with a high level of fixed deliveries. For example, a recent article published by S&P Global Market Intelligence stated the following: "Across the country in 2020, about 48.1% of coal deliveries arrived at U.S. power plants on spot contracts or on contracts with less than a year remaining on the term. Depending on the month in 2020, between 69.5% and 74.1% of coal delivered to U.S. power plants arrived through spot deals or contracts with less than three years remaining in the term."[44]

Q. Mr. Schwartz criticizes your recommendation of a 50 percent threshold for the minimum take quantity relative to expected fuel burn on new coal supplies. How do you respond?

A. While it may be true that many utilities do not adhere specifically to a 50 percent threshold at present, the purpose of proposing a lower threshold is that it anticipates

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[43] PAC/500 at Schwartz/30:18-20.

[44] Taylor Kuykendall, *US coal deliveries increasingly arrive to power plants on shorter-term contract*s, S&P Global (June 25, 2021), *available at* https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/us-coal-deliveries-increasingly-arrive-to-power-plants-on-shorter-term-contracts-65162319 (attached as Exhibit Sierra Club/203).

where trends are headed given the general headwinds for coal economics. That said, I would be willing to consider a minimum take threshold other than 50 percent, within reason, provided that it is consistent with the overall trend towards lower volumes and shorter term lengths.

Q. Mr. Schwartz claims that the largest U.S. producers of coal have over 79 percent of their coal sales committed under contract.[45] Do you find this to be a compelling rationale for a higher minimum take for new contracts?

A. No. While I do not dispute the 79 percent figure, it is worth noting that this figure: 1) does not necessarily equate to the whole industry; 2) does not specify the length of contracts; 3) does not mean these contracts aren't overly optimistic about future coal needs.

Q. Would you be willing to revise your recommendation on the 50 percent minimum take quantity threshold if PacifiCorp accepts full cost responsibility for any penalty payments?

A. Possibly. However, this would depend upon ensuring there is rigorous oversight of PacifiCorp's dispatch practices to ensure that coal is not over-generated simply to meet the minimum quantity.

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[45] PAC/500 at Schwartz/35:3-4.

B. <u>Hunter Coal Supply Agreements</u>

Q. Regarding the minimum take provisions proposed for the Hunter contracts, what does PacifiCorp's reply testimony say?

A. According to Mr. Schwartz, "The minimum take provisions under the Hunter CSAs are only equal to [redacted] of the expected three-year average burn at Hunter. Even if the burn at Hunter turns out to be [redacted] below the expected burn, the Company will not have a problem meeting its minimum take obligations under the new CSAs."[46]

Q. Do you agree with this assessment?

A. Not necessarily. While the minimum take at Hunter is equal to only [redacted] percent of the *expected* burn, this percentage is well below what PacifiCorp forecasted for a plausible low burn scenario, which showed the minimum take equal to [redacted] percent of the projected burn.[47] Thus, while it may be true that the Hunter minimum take could accommodate a burn that is [redacted] percent below expectations, it would not be able to accommodate a burn that is [redacted] percent below expectations. Such a scenario is not unreasonable, especially given potential federal policies that could significantly limit carbon emissions. This would also be similar to reduced burn expectations that have occurred at other PacifiCorp plants which I address in my opening testimony.

[46] *Id.* at Schwartz/35:10-13.
[47] Sierra Club/117.

4. <u>Operational Dispatch Practices</u>

A. <u>iOpt/PCI Forecasts</u>

Q. PacifiCorp's reply testimony spent considerable time responding to your observation that the actual dispatch at Jim Bridger often deviates from the forecast produced by PacifiCorp's energy traders in iOpt or Power Costs Incorporated ("PCI").[48] Do you agree with the Company's assessment?

A. I do in part. In fact, I never disputed the notion that there may be some modest deviations between the forecast and the actual dispatch. That outcome is expected and reasonable. Instead, my primary critique was that the input assumptions used to generate the initial forecast were incorrect because they rely upon the BCC supplemental pricing. The extreme difference between the BCC supplemental price and the BCC base price is significant enough that generation from Jim Bridger is likely being systematically over forecasted by iOpt/PCI, regardless of any subsequent deviations from the forecast.

B. <u>Proper Proceeding to Examine Dispatch Practices</u>

Q. In its reply testimony, PacifiCorp argued that the Commission should not examine the Company's dispatch practices in the PCAM, stating that "[t]he Commission also reiterated that it will not redesign the PCAM parameters until 'around 2024.'"[49] How do you respond?

A. Based on the analysis I presented in my opening testimony, I think there is reason to believe that PacifiCorp may be underestimating the fuel cost of its coal plants when determining optimal dispatch. This leads to an inefficient outcome that could be causing tens of millions of dollars in additional costs to PacifiCorp customers each year than

[48] PAC/400 at Staples/67:18-70:2.
[49] *Id.* at Staples/59:19-21 (quoting Order No. 20-473 at 130).

necessary. It would be unfortunate if the Commission were prevented from examining this issue sooner than 2024. This is especially salient due to the fact that PacifiCorp is poised to join an organized regional energy market that could exacerbate the effect of these dispatch practices.[50] Moreover, it is clear that there is a linkage between PacifiCorp's forecasted fuel consumption examined in the TAM and the actual fuel consumption examined in the PCAM. While some aspects of these issues may need to be addressed more thoroughly in the PCAM proceeding, it does not make sense to construct artificial procedural barriers to gathering relevant information on PacifiCorp's dispatch practices that may inform future TAM and/or PCAM proceedings. As such a continue to recommend that the Commission examine these issues soon.

C. Economic Cycling Analysis

Q. How did PacifiCorp respond to your critique that they had not adequately considered the costs and benefits of economic cycling at coal plants like Jim Bridger?

A. PacifiCorp argued that such an analysis was unnecessary and provided a hypothetical example suggesting that it would be exceedingly rare for the Company to break even from cycling Jim Bridger due to startup costs.[51]

Q. Did you find this hypothetical example convincing?

A. No. While the example presented is a plausible scenario, it is in no way representative of all possible system conditions PacifiCorp is likely to face. For example, there are many

[50] Pete Danko, *Going for the grid: PGE, PacifiCorp undertake a new effort*, Portland Business Journal (Sept. 26, 2019), *available at* https://www.bizjournals.com/portland/news/2019/09/26/going-for-the-grid-pge-pacificorp-undertake-a-new.html.
[51] PAC/400 at Staples/58:3-59:2.

times when the market price would be well below the hypothetical $[redacted]MWh value PacifiCorp analyzed. In instances where the price was lower, it is much more likely that economic cycling would make sense on a shorter timeframe than 53 days. Therefore, PacifiCorp's example is not sufficient to disprove that Jim Bridger could be operating uneconomically on a semi-regular basis.

Q. How else did PacifiCorp challenge your analysis in opening testimony of Jim Bridger cycling?

A. PacifiCorp pointed out that I only analyzed a very short time period, and that Jim Bridger still would have been profitable if the plant had operated at a lower level than PacifiCorp's forecast suggested was the optimal level.[52]

Q. Do you agree with PacifiCorp's conclusions?

A. No. First, it is telling that in this instance PacifiCorp argues that the plant should have operated at a lower level than its own forecast suggested. Second, if PacifiCorp is confident that this one example is not indicative of a larger trend, then I would think the Company would be eager to conduct an analysis to show that the plant is more profitable without cycling over the course of an entire year. However, PacifiCorp refuses to do so.

Q. Have you conducted any additional analysis for a longer time period than what you presented in your opening testimony?

A. Yes. I extended my previous analysis of a single five-day period to cover the full range of iOpt/PCI forecasts PacifiCorp provided from January 2020 through May 2021. This revealed that there were many more instances where the generation units at the Jim

[52] *Id.* at Staples/61:4-11.

Bridger plant were operating at an economic loss. In fact, many of the instances I identified showed losses that were greater than the startup/cycling costs, meaning it would have been more cost effective to cycle the unit off. It is important to note that in some instances the losses for a single day did not exceed the cycling cost, however the losses over the course of several days did exceed these cycling costs. To capture this effect, I examined the sum of economic gains/losses for every five-day period within the time period for which data was provided. The table below summarizes the results of this more comprehensive analysis.

Confidential Table 4: Jim Bridger Economic Cycling Analysis[53]

Generation Unit	**5-Day Periods with Economic Losses Exceeding Startup Costs (January 2020 through May 2021)**[54]	
	Number of Instances	% of Total
Jim Bridger 1	[redacted]	[redacted]
Jim Bridger 2	[redacted]	[redacted]
Jim Bridger 3	[redacted]	[redacted]
Jim Bridger 4	[redacted]	[redacted]

5. <u>Miscellaneous Issues</u>

A. <u>Mischaracterization of Arguments Regarding Dispatch Versus Costing Tier</u>

Q. Do you believe PacifiCorp's reply correctly characterized your arguments regarding the use of the dispatch tier and costing tier prices in the GRID model?

A. No. As one example, PacifiCorp seems to imply that my position is that use of a dispatch tier price to account for a minimum take contract is never warranted.[55] Instead, I am arguing that some of the specific dispatch tier cost inputs PacifiCorp uses for this purpose

[53] Confidential Attachments to PacifiCorp Response to Sierra Club Data Request 2.18.
[54] The instances correspond to individual days, with the 5-day period following that day. Thus a 5-day period starting on 1/1/2021 could overlap with a 5-day period starting on 1/2/2021.
[55] PAC/400 at Staples 52:16-18.

are not correct, most notably the dispatch tier price used for the Jim Bridger plant discussed at length above.

Q. PacifiCorp compared the use of marginal costs to the cost of taking a car trip to the store.[56] Do you think this analogy makes sense?

A. No. PacifiCorp's analogy fails because the evaluation of future NPC is forward looking and must consider all of the relevant costs. Thus, for PacifiCorp's analogy, the more important consideration is not whether to make a daily trip to the store, but whether or not to buy or lease the car in the first place. This would be the equivalent of entering a contract or updating an affiliate mine plan. In those cases, any fixed expenses (*e.g.*, a monthly car payment) that have yet to be incurred are appropriate to consider. In no way is this "counter to basic economic principles."[57] As a concrete example, PacifiCorp states the following regarding BCC: "While BCC is an affiliate captive mining operation adjacent to the plant and can adjust coal production quantities to comply with reasonable changes in fuel requirements at the plant over time, most base costs *within the year of the mine plan* are fixed and unavoidable."[58] Because the TAM is evaluated in the year *before the year of the mine plan*, however, many of these costs are not yet fixed and may still be avoidable.

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[56] PAC/400 at Staples/53:12-22.
[57] *Id.* at Staples/53:22.
[58] *Id.* at Staples/54:13-16 (emphasis added).

B. <u>California Public Utilities Commission ("CPUC") Decision</u>

Q. In his reply testimony, Mr. Ralston stated that "[t]he CPUC rejected Sierra Club's argument in its entirety and found that there was no evidence that any of PacifiCorp's specific coal supply agreements were imprudent."[59] Do you believe this is an accurate characterization of the CPUC's decision in the case referenced (*i.e.*, the 2020 ECAC)?

A. No. None of the newly executed coal supply agreements or open positions being considered in the 2022 OR TAM were evaluated by the CPUC in the 2020 ECAC case referenced. Sierra Club did recently provide arguments in the 2021 ECAC on some of coal contracts at issue in the current 2022 TAM case. However, a decision by the CPUC on the 2021 ECAC is still pending.

C. <u>Open Positions</u>

Q. Did PacifiCorp admit that it assumes open positions for 2022 would include minimum take provisions?

A. Yes. Specifically, Mr. Ralston stated the following: "Sierra Club is correct that the Company has assumed that the open position for 2022 will be filled by CSAs with minimum take provision for the Naughton plant and the Black Butte CSA for the Jim Bridger plant . . . ."[60]

Q. Do you find this to be problematic?

A. Yes. For Black Butte in particular, the dispatch tier costs PacifiCorp assumes are excessively low. Because this is a new contract, it is incorrect to assume that the dispatch

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[59] PAC/600 at Ralston/38:11-13.
[60] *Id.*at Ralston/39:2-4.

tier costs should be so low given that the contract (including minimum take provisions) is not yet finalized.

D. <u>Reliability</u>

Q. Did PacifiCorp raise concerns over grid reliability related to not having enough coal?

A. Yes. Specifically, Mr. Schwartz suggested that recent power shortages in Texas are indicative of what could happen if there is not enough coal fuel.[61]

Q. Do you agree with this comparison?

A. No. The circumstances of the recent outages in Texas are wholly inapplicable to PacifiCorp's situation. While there are important lessons to be drawn from this tragic event, invoking it here represents nothing more than a scare tactic.

Q. Can you elaborate on some of the differences between the Texas power system and PacifiCorp's system?

A. Yes. First, the Texas system, also known as "ERCOT" is its own interconnection that is islanded from neighboring power grids. Thus, ERCOT was unable to benefit from the resource sharing that occurs routinely in the Western Interconnection, and that PacifiCorp could likely avail itself of in an emergency event. Second, a major reason for the outages in Texas was the fact that many power plants lacked the winterization measures needed to maintain operations during extreme cold. In contrast, PacifiCorp's system is much more accustomed to winter operations and would not be likely to face the same challenges. Third, while all types of generation experience failures during the outage—including

[61] PAC/500 at Schwartz/31:14-32:2.

wind, nuclear, coal, and natural gas—by far the most significant failures occurred at natural gas power plants rather than coal. Fourth, the Texas power market has a fundamentally different construct than PacifiCorp in that it is fully restructured and there is no central planning process to ensure resource adequacy. This contrasts starkly with PacifiCorp's system that is vertically integrated and includes a robust Integrated Resource Planning process that ensures a substantial planning reserve margin to maintain reliability. These factors represent just a few of the reasons why drawing parallels between PacifiCorp and ERCOT are not appropriate, and Mr. Schwartz's reliability concerns should be rejected.

E. <u>Response to Other Parties</u>

Q. How did PacifiCorp respond to CUB's proposal to run a GRID study closing [redacted]?

A. PacifiCorp argued against this proposal, suggesting that it is "not a good use of resources."[62]

Q. Do you support CUB's proposal?

A. Yes. Given the significant potential savings from reducing Jim Bridger operations, I disagree with PacifiCorp's assessment that this would not be a good use of resources. Additionally, I will note that the GRID run PacifiCorp conducted using average costs in response to SC 2.22 also appears to have [redacted]. As such, I believe the study that CUB is proposing may lead to similar conclusions as the one PacifiCorp has provided in this response.

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[62] PAC/400 at Staples/40:5-17.

Q. In its reply, PacifiCorp argued against Staff's position that take or pay adjustments (*i.e.*, "reaveraging") in the informational run are inappropriate.[63] Do you agree?

A. No, I support Staff's position on this issue. I believe the reaveraging step PacifiCorp took obfuscates the intent of this informational run. Moreover, I do not believe the results are "meaningless" as PacifiCorp asserts.[64] Even if there are legitimate fixed costs that PacifiCorp is authorized to recover, it is still useful to understand the optimal operating costs to inform future TAM cycles, contracting decisions, and mine plans.

Q. Does this conclude your rebuttal testimony?

A. Yes.

[63] *Id.* at Staples/41:12-42:8.
[64] *Id.* at Staples/42:2.

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

EXHIBIT SIERRA CLUB/201

Exhibit Accompanying the Rebuttal Testimony of Ed Burgess

Sierra Club Data Request 5.5

UE 390 / PacifiCorp
July 27, 2021
Sierra Club Data Request 5.5

Sierra Club Data Request 5.5

CONFIDENTIAL REQUEST - Please refer to PAC/400 at Staples/64:19 through 65:1: "In Data Request 2.5(c), PacifiCorp listed 'wholly identifiable fixed costs' at [CONFIDENTIAL BEGINS] [redacted] [CONFIDENTIAL ENDS] but went on to state that '[o]ther fixed costs are embedded in labor and benefits, materials/supplies, electricity, outside services and other miscellaneous costs that are independent of coal production activities.'"

(a) For each of the items listed (i.e., labor and benefits, materials/supplies, electricity, outside services and other miscellaneous costs), please specify what amount, in dollars ($), reflects the "embedded" fixed cost for 2022.

(b) As of the date of PacifiCorp's initial filing in this case, please provide the actual costs PacifiCorp had already incurred for each of these items in order to produce BCC coal in 2022.

(c) Please provide all contracts or agreements PacifiCorp had executed prior to its initial filing in this case with suppliers of the items listed (i.e. labor and benefits, materials/supplies, electricity, outside services and other miscellaneous costs) for BCC coal production in 2022. Please explain which provisions of these agreements are non-negotiable before 2022.

(d) For each of the items listed, please explain how far in advance PacifiCorp typically enters into an agreement with suppliers to provide these goods or services.

Confidential Response to Sierra Club Data Request 5.5

(a) PacifiCorp objects to this request being vague, unduly burdensome and not likely to lead to admissible evidence relevant to this proceeding. Without waiving this objection, the Company responds as follows:

PacifiCorp does not budget on a fixed verses variable basis, but on a total cost basis, so this information is not available. Additionally, the relationship between fixed and variable costs change depending on the quantity of coal produced and the length of the evaluation period. However, as identified in the Company's response to Sierra Club 2.5, and in the testimony of Mr. Douglas Staples, these fixed costs would be at minimum **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS].**

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July 27, 2021
Sierra Club Data Request 5.5

(b) Costs included in the 2022 TAM incurred prior to April 1, 2021 can be summarized as follows:

[CONFIDENTIAL BEGINS]

Cost Item (PAC Portion)	As of March 31, 2021
Depreciation	[redacted]
Depletion	
Coal Inventory	
Deferred Longwall	
Total	

[CONFIDENTIAL ENDS]

The amount noted above represents costs forecast to be recovered in the 2022 transition adjustment mechanism (TAM) for expenditures incurred prior to April 1, 2021 and does not include costs for obligations Bridger Coal has as of April 1, 2021 that are included in the 2022 TAM. Obligations include costs for final reclamation, property taxes, mine compliance costs, employee benefits (long-term disability), etc.

(c) PacifiCorp objects to this request as being vague, unduly burdensome and not likely to lead to admissible evidence relevant to this proceeding. Without waiving this objection, the company responds as follows:

PacifiCorp has provided confidential detailed work papers supporting the derivation of Bridger Coal costs in the 2022 TAM, including the latest mine plan. If there is a specific cost category or element that is being sought please identify it and PacifiCorp may be able to provide additional detail.

(d) Bridger Coal typically enters into agreements with terms ranging between **[CONFIDENTIAL BEGINS]** [redacted] **[CONFIDENTIAL ENDS]**.

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/202
Witness: Ed Burgess

PUBLIC UTILITY COMMISSION OF OREGON

UE 390

EXHIBIT SIERRA CLUB/202

CONFIDENTIAL

Exhibit Accompanying the Opening Testimony of Ed Burgess

Confidential Attachment to Sierra Club Data Request 2.6

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/203

Exhibit Accompanying the Rebuttal Testimony of Ed Burgess

Taylor Kuykendall, *US coal deliveries increasingly arrive to power plants on shorter-term contracts,* S&P Global (June 25, 2021)

Sierra Club/203
Burgess/1

25 Jun, 2021

US coal deliveries increasingly arrive to power plants on shorter-term contracts

Author **Taylor Kuykendall**

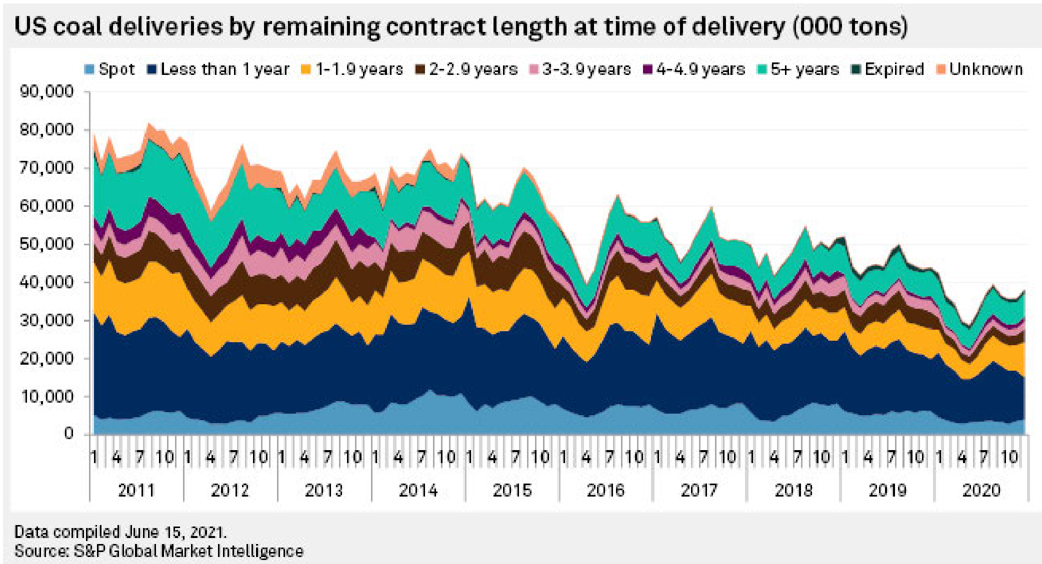
Theme **Energy**

The security of longer-term supply contracts signed between U.S. utilities and coal producers is becoming increasingly rare in an industry struggling with declining demand.

Longer-term contracts offer coal companies the certainty of incoming revenue needed to make investments in future infrastructure. They can also help convince investors of future profitability. An S&P Global Market Intelligence analysis found a growing share of the monthly coal delivered to power plants is arriving with fewer than three years remaining on the contract term. Meanwhile, the percentage of coal provided with over three years remaining in the agreed period is trending downward over the last several years.

Sierra Club/203
Burgess/2

"In my opinion, it's no surprise because the utilities don't really know how much coal-fired power they're going to need," said John Hanou, president of Hanou Energy Consulting LLC. "I think they just don't want to commit to any kind of term because it's possible that the plant may shut down or get out-dispatched by other energy sources, namely, natural gas."



Hanou said that, historically, coal companies have used spikes in coal prices — when utilities are most in need of coal — to lock in longer-term coal contracts. However, over the past few years, coal prices have generally been depressed, even to the point of driving many U.S. coal mining companies to bankruptcy.

In an annual report, Peabody Energy Corp., the largest coal producer in the U.S., said that most of its sales are under agreements of a year or more but also pointed to a trend of customers under long-term agreements seeking shorter-term contracts. Peabody noted its largest customer accounted for approximately 9% of total revenues from coal supply agreements and has contracts expiring at various times between 2021 and 2023.

Peabody attempts to enter into new, long-term supply agreements when the prices and terms and conditions are favorable but the company said customers could be less likely to do so.

Across the country in 2020, about 48.1% of coal deliveries arrived at U.S. power plants on spot contracts or on contracts with less than a year remaining on the term. Depending on the month in 2020, between 69.5% and 74.1% of coal delivered to U.S. power plants arrived through spot deals or contracts with less than three years remaining in the term. That compares to between 62.3% and 67.3% of coal deliveries across the months of 2011.

As recently as February 2012, 21.3% of coal arrived on contracts with more than five years remaining in the term. While that figure dropped to as low as 11.5% in April 2017 and has generally trended lower since 2021, the share of coal delivered on contracts of greater than five years remaining increased slightly through 2020.

Robert Godby, an energy economist at the University of Wyoming, said shorter-term contracts give power plants more flexibility with fuel and operating costs and reduces uncertainty.

"They don't want to be on the hook for a long-term take or pay contract where they don't need the coal," Godby said. "In some cases, it may be a question of an early retirement, but regardless, capacity factors are falling, and falling quickly."

After recent bankruptcy-related disruptions in the Powder River Basin, some power plants may also be skeptical of a smaller operation's ability to fulfill a longer-term contract, Godby said. Additionally, the economist said,

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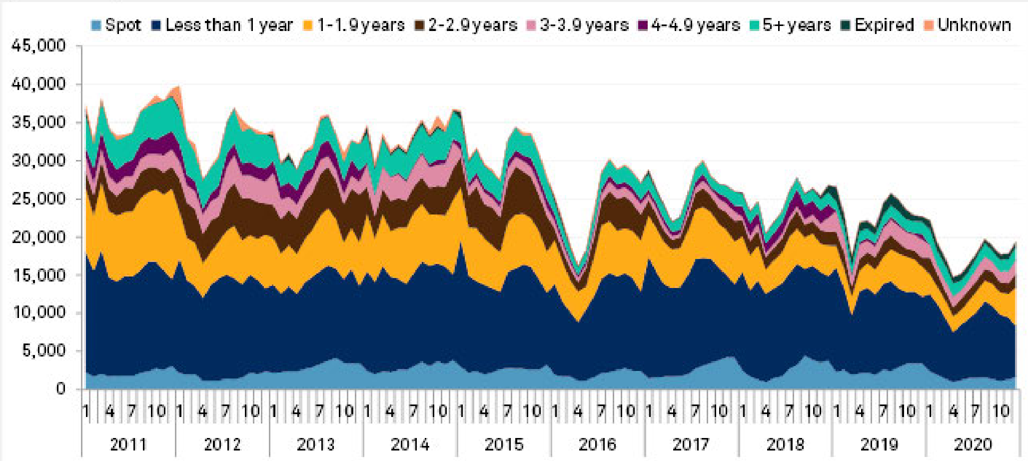
the declining number of contracts is a serious concern for smaller mines. Particularly in the Powder River Basin in the western U.S., mines rely on economies of scale. A reduced customer base increases uncertainty, leading to a "downward spiral effect" where mines become increasingly unviable.

Powder River Basin coal deliveries by remaining contract length at time of delivery (000 tons)



Data compiled June 15, 2021.
Source: S&P Global Market Intelligence

"As contracts go away, uncertainty mounts," Godby said. "Costs also rise due to reduced economies of scale, and they rise if financial market access is reduced, reducing reinvestment, reducing the mines' competitiveness as costs increase, worsening uncertainty and access to capital, increasing costs and so on."

The Institute for Energy Economics and Financial Analysis, or IEEFA, recently counted 82.3 GW of announced coal plant retirements and conversions for 2021 through 2030, up more than 11 GW since March, said IEEFA data analyst Seth Feaster. The analyst said there was also a "huge rise" in coal plant retirements slated for 2031 to 2040, up to 36.1 GW from 19.4 GW in March.

Feaster said a trend toward shorter contracts reflects how quickly a transition from coal is occurring and how utilities are becoming less committed to the fuel. The analyst said utilities are "understandably

Sierra Club/203
Burgess/5

reluctant" to lock in long-term contracts due to retirements combined with lower coal utilization rates, an overhang in coal stockpiles, uncertainty around gas prices and a diminishing economic case for coal-fired power.

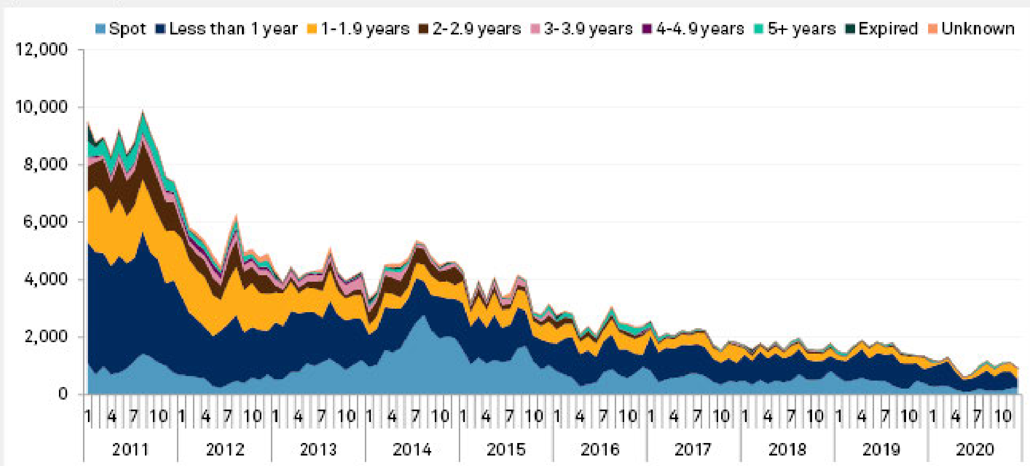
"For miners, the short-term risks are growing significantly, imperiling capital investment decisions and planning in general with short-term contracting, compounded by the number of customers rapidly dwindling," Feaster said.

Coal supply risks are also growing for utilities, the analyst said, increasing the potential for unexpected disruptions into 2022 and beyond.

"There continues to be way too much supply chasing an ever-shrinking market," Feaster said. "Coal-market conditions may have stabilized somewhat after last year's sharp drop and the increase in gas prices, but it's only temporary before the next leg down."

The trends vary slightly by region. For example, in Central Appalachia, coal deliveries to power plants on contracts with more than two years remaining on the term are nearly nonexistent. As the region depleted much of its coal reserves, producers began to focus on higher-margin metallurgical coal, which is not part of the analysis of coal delivered to power plants. The price of the steelmaking product fluctuates and is often sold domestically abroad on shorter contract terms.

Central Appalachia coal deliveries by remaining contract length at time of delivery (000 tons)



Data compiled June 15, 2021.
Source: S&P Global Market Intelligence

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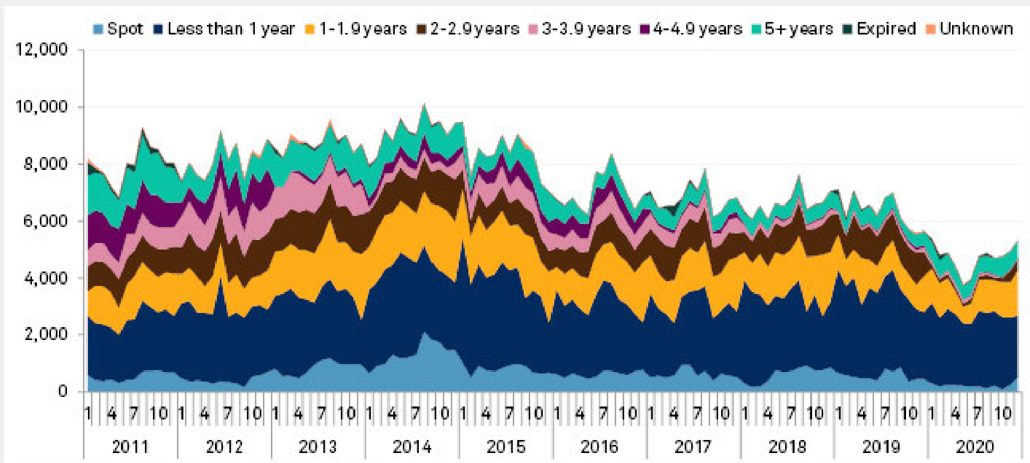
Burgess/6

After a dip in production early in the year, both the Illinois Basin and Powder River Basin saw increases in coal deliveries in the second half of 2020, though they did not recover to 2019 levels. In both regions, deliveries predominantly arrived through contracts with two years or fewer remaining on the term.

Hallador Energy Co. CEO Brent Bilsland noted on a May 4 earnings call that a return to longer-term coal supply contracts could help alleviate a "risk premium" hanging over companies in the coal sector such as his Illinois Basin coal company.

Illinois Basin coal deliveries by remaining contract length at time of delivery (000 tons)



Data compiled June 15, 2021.
Source: S&P Global Market Intelligence

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 30th day of July, 2021, I have served true and correct copies of the Confidential Rebuttal Testimony and Exhibits of Ed Burgess pursuant to Protective Order No. 16-128 upon all eligible party representatives electronically via encrypted password protected ZIP folders.

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Dated this 30th day of July, 2021 at Oakland, CA.

/s/ Ana Boyd

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