BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 77

In the Matter of PACIFICORP, dba PACIFIC POWER, 2021 Integrated Resource Plan.	Staff Report

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Introduction

The PacifiCorp 2021 IRP has provided a framework for understanding the Company's 20-year plan to acquire resources to serve customers. Staff has appreciated a productive conversation with PacifiCorp and stakeholders through the IRP lead-up process, filing, and comments.

This IRP takes a bold stance on reducing greenhouse gas (GHG) risk by eliminating new GHG-emitting resources from the portfolio, showing that PacifiCorp is taking the risks of climate change and future greenhouse gas regulation seriously. PacifiCorp's Reply Comments supported this decision by noting the significant stranded cost risk from GHG-emitting plants that will have depreciable lives of up to 40 years, ending as late as 2070. With state and national GHG targets coalescing around dates closer to 2040 and 2050 for ambitious carbon reduction targets, new emitting resources carry significant stranded cost and GHG regulation risk.

While the 2021 IRP is not informed by a Clean Energy Plan, PacifiCorp has noted that it is on track to meet the HB 2021 2030 target of an 80 percent reduction in GHG emissions by 2030.[1] Staff is pleased to see this initial indication of the Company's ability to comply with HB 2021, and looks forward to more discussion in 2023 IRP public input workshops regarding how HB2021 will be considered in the 2023 IRP and its associated Clean Energy Plan.

Staff's final comments and recommendations discuss parts of the 2021 IRP for which, after a thorough review, Staff continues to have questions, concerns, and recommendations. Staff's concerns regarding the 2021 IRP are generally around transparency and accuracy of the modeling inputs.

Regarding transparency, typographical errors and inaccurate data provided in the IRP create confusion and frustration for stakeholders and PacifiCorp should seek to avoid these issues in future IRPs. Additionally, Staff's requests for data on the costs of a 230 kV alternate to Energy Gateway South and itemized costs of the Jim Bridger gas conversion were not met with responses that adequately showed these costs. More detailed responses would have assisted to review important claims regarding the transmission system and gas conversion.

IRP modeling inputs of concern to Staff include the cost and risk assumptions around the Natrium plant and the Take or Pay assumptions for the Jim Bridger 3 and 4 plants. These are major items of concern that call into question some of the results of the 2021 IRP. Ultimately, Staff finds that these concerning IRP modeling assumptions would not create major differences in PacifiCorp's 2-4 year Action Plan. One major concern, however, is the questionable inclusion of the Natrium Plant in the preferred portfolio and its potential impact on the outcome of the 2022 AS RFP.

In later years of the planning timeframe, the problematic modeling assumptions around Natrium and potentially Jim Bridger have larger impacts. Because of Staff's significant concerns regarding the Natrium plant, Staff recommends acknowledging the preferred portfolio only to

[1] PacifiCorp's Reply Comments. Page 80.

the extent it is consistent with the no-Natrium sensitivity which removes the 2028 Natrium nuclear plant.

Section 1: 2021 IRP Modeling

1.1 Portfolio Selection, Development, and Evaluation

Section 1 of Staff's Final Comments and Recommendations discusses key issues related to portfolio modeling and development, including generation, transmission, resource adequacy, and demand side resources.

1.1.2 Generation Resource Modeling

The following section addresses key issues associated with generation resource modeling, as identified by Staff and stakeholders. The main issues around which Staff provided comments and conducted inquiry were coal economics, the inclusion and consideration of Natrium nuclear, hydrogen peakers, offshore wind, supply side resource cost and location, reliability of resources, planning reserve margin, pumped hydro storage, and market purchases and proxy resources.

Coal Economics

The economics of PacifiCorp's 22 coal units has been a topic of ongoing discussion and study in recent IRP cycles, and the 2021 IRP shows both progress and room for improvement. Regarding the economics of the coal fleet in general, Sierra Club noted in its opening comments that PacifiCorp did not provide a unit-by-unit analysis of its coal fleet in the 2021 IRP. Sierra Club's comments stated that the unit-by-unit analysis in the 2019 IRP was informative and necessary, as it provided valuable information and served as a check on the portfolio-wide results.[2] Staff concurs with Sierra Club that some of the results of the endogenous coal retirement analysis in the 2021 IRP seem counter-intuitive in certain instances, and that a metric describing the value of each coal unit to the system would be valuable for checking the results of PacifiCorp's portfolio modeling against a measurement of each coal unit's value to the system.

Staff's understanding is that the Plexos model is capable of reporting portfolio results that provide an estimate of the value of each new and existing resource in the preferred portfolio.[3] Staff proposes that instead of performing individual Plexos model runs for each coal unit, which could be time-consuming, PacifiCorp should report the Plexos-calculated value of each coal unit in a table in its next IRP.

Additionally, the IRP data discs should provide graphs of the average fixed and variable costs of operating each coal unit over the planning timeframe. This should include fuel cost and run rate

[2] Sierra Club Opening Comments. Page 3.
[3] PacifiCorp's Reply to Staff DR 106.

capital, but exclude depreciation expense. This will provide a check on the reasonableness of coal retirement results that is independent from other Plexos modeling assumptions.

Recommendations:

Recommendation 1: In the 2023 IRP, PacifiCorp should provide a metric calculated in its capacity expansion model that provides stakeholders with an estimate of the relative value of each coal unit to the system.

Recommendation 2: If the data on the relative value of each coal unit is available for 2021 IRP resources, the Company should provide the data in a filing before the acknowledgement decision meeting. If the data is considered confidential, then a ranked table of PacifiCorp's coal units from least to most valuable should be provided in the filing in a non-confidential format.

Recommendation 3: The 2023 IRP data discs should provide graphs of the average fixed and variable costs of operating each coal unit over the planning timeframe. This should include fuel cost and run rate capital, but exclude depreciation expense.

Coal Fuel Price Modeling

Regarding coal fuel prices as modeled in the IRP, Sierra Club's Opening Comments argued that the coal fuel price modeling in Plexos is problematic and inaccurate. PacifiCorp states in its Reply Comments that, "While some of these coal resources are dispatched based on take or pay contracts, with an incremental cost that is lower than the average, this structure is consistent with many of the Company's existing obligations and comparable structures are likely in future coal supply procurement."[4] Staff's view is that PacifiCorp is correct, and the Plexos model is capable of accurately modeling the dispatch of coal plants using several different price tiers. Staff agrees with PacifiCorp that Plexos' advanced capabilities make the model capable of accurately reflecting the actual cost of dispatch at coal units. As long as the fuel price tiers modeled in Plexos match those in PacifiCorp's actual coal supply agreements, the Plexos modeling should be accurate and dispatch coal units at economically efficient levels. Staff's review of modeled coal prices in the IRP did not find substantial divergence from actual prices in existing contracts.

Jim Bridger 1 and 2 Gas Conversion

In response to PacifiCorp's plan to convert Jim Bridger 1 and 2 to natural gas, several stakeholders, including Green Energy Institute (GEI), Renewable Northwest (RNW), and Sierra Club, expressed concern about the conversion and its contribution to greenhouse gas emissions (GHG) on PacifiCorp's system in Opening Comments.[5,6,7] Staff understands the concern from

[4] PacifiCorp Reply Comments. Page 23.
[5] Sierra Club Opening Comments. Pages 32-38.
[6] Green Energy Institute Opening Comments. Pages 2-3.
[7] Renewable Northwest Opening Comments. Pages 5-6.

stakeholders around GHG emissions of converted gas plants. However, in Opening Comments, Staff supported the coal-to-gas conversion as a reasonable way to provide flexible peaking capacity to the system.

Staff continues to support the coal-to-gas peaker conversion for Jim Bridger 1 and 2. As described later in this section, Staff has found that the GHG savings that would likely result from retiring Bridger 1 and 2 instead of converting them to gas would be relatively expensive and that other, more cost-effective approaches to GHG reduction should be preferred. In addition, gas conversion retains valuable flexible capacity generation on PacifiCorp's system. In fact, conversion to natural gas may improve the flexibility and minimum operating levels of a coal plant.[8,9] This type of flexible capacity can help facilitate the integration of variable energy resources while removing the need to sign risky multi-year coal supply agreements or install expensive selective catalytic reduction (SCR) equipment at these units.

Regarding the potential GHG emissions at the converted units, Staff expects that the converted units are likely to run at low capacity factors as peakers, so emissions will be limited. Heat rate is a measure of plant efficiency based on the quantity of Btus of heat energy that a plant uses to produce one kWh of electrical energy. The Bridger coal units on average utilized 10,693Btu/kWh in 2020.[10] Combined cycle plants on PacifiCorp's system on average utilized 7,404 Btu/kWh, which demonstrates that Bridger is already much less efficient than PacifiCorp's gas fleet.[11] Various literature indicates that coal to gas conversion can further reduce boiler efficiency by approximately 5 percent.[12] Additionally, one Btu of natural gas tends to be about 35 percent more expensive than one Btu of coal, so even at the same heat rate, a gas conversion would increase fuel costs per MWh. [13] Thus, the converted Jim Bridger units can be expected to have high fuel costs, and for this reason will be unlikely to have a high capacity factor or to have total emissions in the same range as a typical coal or gas plant with the same nameplate capacity.[14]

PacifiCorp appears to be pursuing gas conversion at Jim Bridger 1 and 2 in part to avoid costs associated with SCR at those units. This may explain why gas conversion was considered at units 1 and 2, but not at units 3 and 4, which already have SCR. In short, gas conversion appears to be a cost-effective way to maintain and potentially improve the Jim Bridger units' flexibility and value to the system, while avoiding the need for SCR equipment and reducing GHG emissions significantly.

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[8] https://www.powermag.com/practical-considerations-for-converting-industrial-coal-boilers-to-natural-gas/

[9] https://www.power-eng.com/coal/de-bunking-the-myths-of-coal-to-gas-conversions/#gref

[10] PacifiCorp's 2020 FERC Form 1.

[11] PacifiCorp's 2020 FERC Form 1.

[12] https://www.babcockpower.com/wp-content/uploads/2018/01/leveraging-natural-gas-technical-considerations-for-the-conversion-of-existing-coal-fired-boilers.pdf Page 10.

[13] https://www.eia.gov/electricity/annual/html/epa_07_04.html

[14] The full load heat rate of the converted gas units is expected to be **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** Btu/kWh.

Staff finds that gas conversion for these units is a reasonable step toward a reliable, cost-effective, clean energy system for PacifiCorp customers. Given that on average the combined units are expected to generate **[Begin Confidential]** [redacted] **[End Confidential]** per year, with an expected capacity factor of **[Begin Confidential]** [redacted] **[End Confidential]**, they appear to provide valuable flexible capacity and reliability with a good balance of low emissions and low cost. The forecast emissions at Jim Bridger 1 and 2 are provided in Table 1 below.

[Begin Confidential]

[redacted]

[End Confidential]

Staff also finds that the gas used by the converted units will likely not create significant gas price risk. If gas prices increase to significantly higher levels than expected, the converted units can reduce costs by further reducing their capacity factors while continuing to provide valuable long-duration dispatchable capacity during hours with high Loss of Load Probability.

Regarding stranded cost risk, the converted units are expected to have a cost of about $25/kW. Therefore, at the units' combined capacity of 700 MW, the gas conversion should cost about $18 million.[15] For a resource with about 700 MW of highly flexible and dispatchable capacity, this seems to be an opportunity with significant benefits in terms of reducing emissions while maintaining reliability.

[15] PacifiCorp's Reply to Staff DR 076.

For reference, in a portfolio without Jim Bridger 1 and 2 gas conversion, Jim Bridger 1 and 2 retire in 2023, and emissions would be reduced by about 8.7 million tons while portfolio costs would increase by about $477 million dollars, which would equal a cost of about $54/ton.[16,17] Given that the current federal social cost of carbon is about $51/ton, avoiding gas conversion of Jim Bridger 1 and 2 may not be the best investment in GHG reduction, even from a societal perspective.[18]

Staff inquired with PacifiCorp about the possibility of running a converted Bridger unit on part or all green hydrogen. PacifiCorp' initially responded that this would likely not be possible, but did not explain. Staff requests that PacifiCorp perform a more thorough investigation of the potential to burn green hydrogen at the converted Bridger units and report on its findings in the 2023 IRP. Additionally, Staff would like the 2023 IRP to more thoroughly investigate the potential to install new turbines designed to run on 100 percent green hydrogen at the sites of one or more retiring coal plants. This is an approach currently being utilized by several companies with retiring coal plants, including Tristate and Intermountain Power Agency.[19,20]

Recommendations:

Recommendation 4: Perform an investigation of the potential to burn green hydrogen at the converted Bridger units and report on its findings in the 2023 IRP, including an explanation of the engineering reasons that a converted boiler would or would not be able to accommodate a percentage of green hydrogen.

Recommendation 5: If technically feasible, PacifiCorp should report on the costs and emissions (CO2 and NOX) of green hydrogen combustion at the converted Bridger unit.

Recommendation 6: The 2023 IRP should more thoroughly investigate the potential to install a new turbine designed to run on 100 percent green hydrogen at the sites of one or more retiring coal plants.

[16] PacifiCorp 2021 IRP. Page 269.
[17] PacifiCorp 2021 IRP. Page 270.
[18] https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf Page 7.
[19] https://www.ipautah.com/ipp-renewed/
[20] https://nmpoliticalreport.com/2021/04/20/the-retired-escalante-power-plant-may-be-converted-into-a-hydrogen-plant/

Jim Bridger 3 and 4 Modeling

Minimum Take Assumptions

Staff understands that the Company expects to have a high minimum take quantity at Jim Bridger due to the very limited coal supply options in the region. With only one supplier for the Jim Bridger coal plant, PacifiCorp has limited leverage to negotiate coal contract terms.

Staff and other stakeholders have expressed concern around the modeling of Jim Bridger 3 and 4 and their inclusion in the preferred portfolio through 2037. One specific concern is the lack of clarity around Take or Pay modeling, and the **[Begin Confidential]** [redacted] **[End Confidential]** even in years after existing coal contracts expire.

Staff remains concerned that the Take or Pay assumption for Jim Bridger 3 and 4 may be modeled incorrectly, preventing Plexos from making an economically reasonable decision regarding its retirement. In Opening Comments, Staff and Sierra Club noted concern about the inclusion of a Take or Pay quantity at Jim Bridger 3 and 4 in years after the end of any existing contract.[21,22] PacifiCorp replied that, "The Company's 2021 IRP results reflected the assumption that when a plant is retired it no longer incurs any take or pay costs from that point forward." Staff is confused by PacifiCorp's statement because it seems contrary to the nature of Take or Pay requirements, which necessarily require a penalty if the fuel is not utilized. Staff requests an explanation of the modeling and how it allows a Take or Pay quantity to be optional.

Staff is especially concerned that the Take or Pay assumption for Jim Bridger 3 and 4 may be distorting the Plexos model's decision making. Staff understands that one option for modeling take or pay contracts in Plexos is to assign a cost of zero dollars to the Take or Pay tier of fuel, and only add the fuel costs after the model has chosen to dispatch the plant up to the Take or Pay quantity.[23] This approach may be reasonable during years when an existing Take or Pay contract is in place, because that quantity of fuel is truly a sunk cost. However, it would be a problematic approach if applied to later years for which no Take or Pay agreement currently exists. For example, if this modeling option were used in the later years of the Jim Bridger plant's life, then the model would make retirement decisions based on the choice between receiving a large quantity of zero-cost fuel, or giving up that same large quantity of free fuel to choose early retirement. It is easy to see how the model could make an incorrect decision to continue running the plant.

To address this concern, Staff has requested a sensitivity that removes any Take or Pay assumptions in Plexos in any years after there is an existing contract.[24] Staff requests that PacifiCorp provide the results of this sensitivity in Docket LC 77 at least one week in advance of the February 24, 2022, Commission workshop. Staff looks forward to discussing the coal sensitivity at that meeting. Additionally, Staff requests that PacifiCorp be prepared for a

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[21] Sierra Club Opening Comments. Page 13.

22 Staff Opening Comments. Page 6.

[23] OPUC Commission Workshop of January 13, 2022 at 54 minutes.

[24] Staff Opening Comments. Page 34.

thorough and detailed discussion of the modeling of the Take or Pay contract for Jim Bridger 3 and 4 in the preferred portfolio, in response to Staff's concerns stated above.

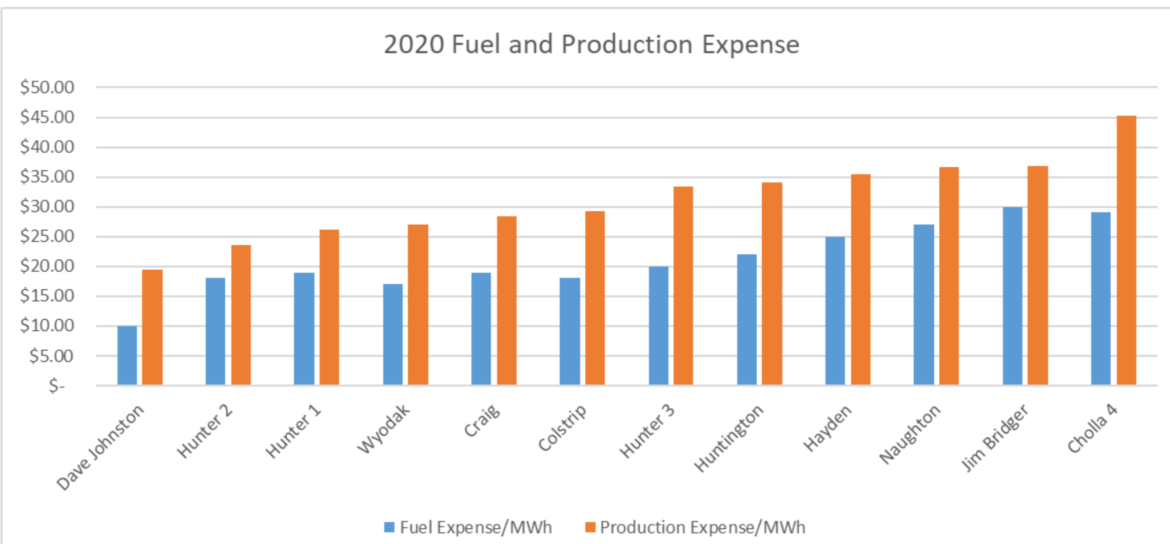
Recommendation 7: PacifiCorp should file the results of its coal sensitivity at least seven (7) days before the February 24, 2022 Commissioner Workshop in LC 77, and be prepared for a discussion of Take or Pay modeling at Jim Bridger 3 and 4.

Jim Bridger 3 and 4 Costs

Staff has been skeptical of Jim Bridger 3 and 4 remaining in the IRP preferred portfolio through 2037 in part because of the units' high variable costs. Staff would like to further discuss variable costs at this time, as well as the fixed costs of keeping the plant online to provide flexible capacity. While the high variable costs at these units make the plants expensive from an energy perspective, the high nameplate capacity of the plant (about 2,300 MW in total and about 1,425 MW owned by PacifiCorp) help to distribute any fixed costs over a higher number of MW of capacity.

FERC Form 1 data from 2020 shows that Jim Bridger units had the highest fuel and production expenses of any coal units on PacifiCorp's system in 2020.[25] This is part of why the inclusion of Jim Bridger 3 and 4 as coal units through 2037 has been surprising.

Figure 1: 2020 Coal Fuel and Production Expenses



Sierra Club's Opening Comments also provide analysis by a third party showing that Jim Bridger units are four out of the five coal plants with the highest Levelized Cost of Energy on PacifiCorp's system. [26] The following table from the 2019 IRP coal study also showed the Bridger 3 and 4 units to provide the fifth and sixth highest benefit from individually retiring in 2022:

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[25] PacifiCorp's 2020 FERC Form 1.

[26] Sierra Club Opening Comments. Page 8.

Table 2: Ranked Unit-by-Unit Coal Study Results from 2019 IRP Coal Study

Table R.2 – Unit-by-Unit Coal Study Results Ranked by Potential Customer Benefits

Coal Unit	PacifiCorp Share Capacity (MW)	PacifiCorp Percentage Share (%)	State	Ranking (High to Low Potential Customer Benefits)
Colstrip 3	74	10	MT	17
Colstrip 4	74	10	MT	16
Craig 1	82	19	CO	11
Craig 2	83	19	CO	9
Dave Johnston 1	106	100	WY	12
Dave Johnston 2	106	100	WY	13
Dave Johnston 3	220	100	WY	14
Dave Johnston 4	330	100	WY	18
Hayden 1	44	24	CO	7
Hayden 2	33	13	CO	8
Hunter 1	418	94	UT	10
Hunter 2	269	60	UT	15
Hunter 3	471	100	UT	20
Huntington 1	459	100	UT	22
Huntington 2	450	100	UT	19
Jim Bridger 1	354	67	WY	1
Jim Bridger 2	359	67	WY	2
Jim Bridger 3	349	67	WY	6
Jim Bridger 4	353	67	WY	5
Naughton 1	156	100	WY	4
Naughton 2	201	100	WY	3
Wyodak	268	80	WY	21

[27]

However, to help further inform the question of whether these units are economic on PacifiCorp's system or should be retired early, Staff would like to add context by sharing the 2021 IRP forecast of average Fixed operation and maintenance (O&M) and Run Rate Capital for PacifiCorp's coal plants over the first six years of the planning timeframe, in \$/kW-yr.

[27] PacifiCorp's 2019 IRP. Appendix R. Page 594. Emphasis Added

[Begin Confidential]

[redacted]

[redacted]

[redacted]

[End Confidential]

The Bridger plant has a higher nameplate capacity than many coal plants on PacifiCorp's system (about 2,300 MW as compared to Dave Johnston's approximately 800 MW.) Therefore, any fixed costs at these units can be divided amongst more kW of capacity than most other plants, reducing the cost of capacity in $/kW-yr compared to a smaller plant with similar costs.

<u>CETA Costs in the Jim Bridger Early Retirement Portfolio</u>

Sierra Club has noted that the JB early retirement portfolio, P02h, may be consistent with CETA requirements because of its increased renewable energy, and therefore could avoid the need for $164 million in co-located solar, wind, and storage allocated to Washington in 2030 in the

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[28] See PacifiCorp Confidential Data Disc. "Input Assumptions CONF\Input Assumptions\Master Assumptions\BaseCase\Plexos Input_Existing coal cost_ 21IRP_Base_20210602_CONF.xlsx"

[29] A similar trend is present throughout the 20 year timeframe.

preferred portfolio.[30,31] PacifiCorp responded in Reply Comments that it would not be appropriate to select the P02h portfolio based on its ability to reduce costs of meeting CETA requirements, since that would not necessarily result in a least-cost portfolio for other states.[32] Staff finds that, if the intent is to make sure that each state is assigned the costs associated with its legislative requirements instead of sharing costs of state-specific policy among jurisdictions, then this response is reasonable. Staff does not take a position on whether this is the most appropriate planning approach at this time.

However, the cost of P02h is only about $60 million higher than the P02-MM portfolio to which it is directly comparable. This is not a large margin, and it seems plausible that the selection of different reliability resources, such as hydrogen or storage instead of nuclear, could potentially have resulted in P02h being lower cost than P02-MM. Because the economics of Jim Bridger 3 and 4 appear to be marginal, PacifiCorp should continue to look carefully at early retirement for these units in its next IRP.

Recommendations:

Recommendation 8: The 2023 IRP should consider endogenous retirement of Jim Bridger 3 and 4 at least once every two years.

Recommendation 9: In the 2023 IRP, PacifiCorp should carefully review the capital and O&M cost forecasts for Jim Bridger 3 and 4 and provide workpapers comparing historical costs at these units to the IRP cost forecast, including the categories of Variable O&M, Fixed O&M, and run-rate capital.

Recommendation 10: In the 2023 IRP, variable O&M costs should be modeled accurately as variable with generation, and not approximated as part of fixed O&M costs as they have been in the 2021 IRP. [33]

Huntington Coal Supply Agreement (CSA) Reopener Clause

Staff appreciates Sierra Club's comments regarding the possibility that federal environmental regulations, including Regional Haze requirements that could be mandated after July, 2022, could trigger a reopener clause in the Huntington CSA. This is an important possibility that the Commission should monitor. Staff proposes that further conversation can be initiated by stakeholders, PacifiCorp, or the Commission immediately as soon as a federal environmental regulation that is likely to trigger this clause appears likely to be enacted.

[30] PacifiCorp 2021 IRP. Page 290.
[31] Sierra Club Opening Comments. Page 16.
[32] PacifiCorp Reply Comments. Page 16.
[33] PacifiCorp's Reply to Staff Dr 091.

Sierra Club writes that a sensitivity where the Huntington contract is re-opened should have been provided with the IRP.[34] Staff is interested in better understanding a scenario where Huntington is able to retire before 2036 because of the CSA provision on environmental regulation. Staff agrees that a thorough exploration of the costs and benefits of contract renegotiation should include a sensitivity where the Huntington CSA can be retired early.

Recommendation:

Recommendation 11: PacifiCorp should perform a sensitivity before the acknowledgement decision meeting in this IRP on March 22, 2022, where the Huntington minimum take agreement ends in 2023.

Coal Unit EIM participation

Staff is continuing to look into PacifiCorp's EIM bidding practices for its thermal plants and whether they result in optimal economic dispatch. This is especially important for the more expensive thermal units on the system, since inappropriate EIM bidding could cause them to generate at high levels that significantly impact customer costs. Because PacifiCorp passes EIM costs and benefits to customers in power cost proceedings, the Company does not have a strong financial incentive to bid in ways that maximize benefits to customers. For this reason, Staff has begun reviewing bidding practices to ensure that bids are designed to result in economic dispatch. Staff has issued several DRs in this docket on EIM bidding practices and historical bids and will report at an appropriate time on any findings.

Natrium Nuclear

The Natrium nuclear plant was included in the preferred portfolio and excluded in a no-Natrium sensitivity. While the no-Natrium sensitivity resulted in a higher NPVRR than the preferred portfolio, there are a variety of issues raised by Staff and Stakeholders flagging concerns about its inclusion. These issues included questions about costs, the unique risk profile of nuclear, the impact the plant has on resource selection in the preferred portfolio, and the mechanism by which the company is pursuing procurement.

The inclusion of the Natrium nuclear plant was criticized by stakeholders in opening comments, including RNW, GEI, CUB, and Sierra Club. RNW and GEI noted that the inclusion of the plant was a surprise near the end of a long stakeholder process. RNW questioned whether enough is known about the nuclear plant to show that PacifiCorp has identified the "best combination of expected costs and associated risks and uncertainties for the utility and its customers" as described in IRP guideline 1(c).[35] GEI noted that the Natrium plant is taking up space in the preferred portfolio that could be allocated to less risky resources: "the inclusion of the Natrium Nuclear Demonstration plant in PacifiCorp's 2021 IRP impacts other resource decisions in the

[34] Sierra Club Opening Comments. Page 14.
[35] Renewable Northwest Opening Comments. Page 3.

action plan, and without a robust and honest discussion of all the risks, the company is missing an opportunity to evaluate and potentially select other less risky, more available, and more proven resources that are also emissions free."[36]

NWEC pointed out in its Opening comments that, "...there is no basis on which to make claims regarding cost or performance of the proposed Natrium project."[37] NWEC is correct, given that the plant is a one-of-a-kind demonstration project and no agreements or recent experience currently exist regarding the Natrium plant that could inform the costs of the plant to customers.[38] NWEC expressed the view that the Natrium project cannot be acknowledged as it now stands, given the risks the project poses for customers.[39]

CUB noted many risks associated with a demonstration nuclear plant and nuclear generally, including risk of nuclear disaster, cost or construction time overrun, fuel storage issues, and fuel supply chain issues.[40] CUB requests that the Company explore options that are lower risk capacity resources.

Costs of Natrium

Stakeholders have expressed concern about the Natrium plant being hard-coded into the preferred portfolio. Staff understands that, while not ideal, the hard-coding was done for modeling efficiency purposes and is not necessarily problematic. The no-Natrium sensitivity shows that the inclusion of the Natrium plant, as modeled, reduces the cost of the preferred portfolio. The issue with the Natrium plant in Staff's view is not that it has been hard-coded into the model, but that it has been assigned cost assumptions that do not appear to reflect many of the risks of constructing and utilizing the plant.

The addition of the Natrium plant, using PacifiCorp's cost assumptions, appears to create cost savings in the preferred portfolio. This is demonstrated by the no-Natrium sensitivity, where costs increase after the removal of the Natrium plant from the preferred portfolio. Unfortunately, PacifiCorp provided no evidence or reasoning to support the cost data provided by TerraPower that assumes that the Company will be able to acquire the Natrium plant at **[Begin Confidential]** [redacted] **[End Confidential]** installed costs as assumed in the 2021 IRP, and that fuel can be acquired at a cost of **[Begin Confidential]** [redacted] **[End Confidential]**[41] Accordingly, there is no reason to believe the plant will create the cost savings claimed in the 2021 IRP.

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[36] Green Energy Institute Opening Comments. Page3.
[37] NWEC Opening Comments. Page 8
[38] PacifiCorp's response to CUB DR 02.
[39] NWEC Opening Comments. Page 8
[40] CUB Opening Comments. Page 2.
[41] PacifiCorp's Response to CUB DR 1. Attachment 1.

Additionally, it is unclear whether PacifiCorp has included primary and secondary insurance in its cost estimates for Natrium, as there are no insurance costs clearly labeled in the Natrium cost estimate.[42,43]

CUB requested sensitivities around cost overruns at the Natrium plant, and Staff supports this idea. However, Staff is also concerned about unexpected increases in fuel cost or other operating costs over the lifetime of the plant due to supply chain or operational issues. The type of fuel expected to be used at the Natrium plant is not currently commercially available and Natrium's unique design is untested. The risks appear to be substantial and should be thoroughly evaluated.

Risks of Natrium

Aside from the unknown cost characteristics of Natrium, nuclear has a unique risk profile which did not receive any analytical attention in the IRP. The risks of procuring a fuel that is currently not commercially available and then safely utilizing, processing, and placing that fuel into long-term storage are significant. PacifiCorp was dismissive of stakeholder concerns regarding the company's lack of experience with nuclear, stating that "PacifiCorp will be required to meet NRC requirements" and that "PacifiCorp has a proven track record of successfully operating generation facilities."[44] However, the consequences of error with nuclear plants can be very high, and any company will have a learning curve.

Staff would like to note that sodium-bonded nuclear fuel in particular must be processed before disposal.[45]The history of processing for this fuel in the United States is mostly limited to the experience of the Department of Energy in attempting to manage spent fuel from three experimental reactors and the 69 MW Fermi-1 sodium-cooled reactor, which experienced a partial meltdown in 1966, and was decommissioned soon after. Several approaches to processing sodium-bonded fuel have been evaluated, and PacifiCorp's cost assumption of only **[Begin Confidential]** [redacted] **[End Confidential]** in costs for spent fuel does not seem proportionate to historical estimated costs for fuel processing. For context, the Department of Energy estimated in 2005 that processing and disposing of the waste sodium-bonded fuel from three reactors would cost over $265 million (over $370 million in 2022 dollars)[46,47] These units combined have approximately the same capacity as the Natrium design, and collectively ran for about 54 years. Cost for spent fuel processing at these plants can therefore be estimated at over 6 million dollars per year. [48,49]

Finally, nuclear plants have historically experienced lengthy construction delays and there is not a lot of recent history to consider. In the preferred portfolio, PacifiCorp is staking its ability to meet customer demand in a least cost manner on the assumption that Natrium can be

[42] PacifiCorp's Reply to CUB DR 1.
[43] https://www.nrc.gov/reading-rm/doc-collections/fact-sheets/nuclear-insurance.html.
[44] PacifiCorp Reply Comments, Page 33.
[45] Idaho National Laboratory. Preferred Disposition Plan for Sodium-Bonded Spent Nuclear Fuel. Page i.

[47] Idaho National Laboratory. Preferred Disposition Plan for Sodium-Bonded Spent Nuclear Fuel. Page 17.
[48] https://world-nuclear.org/information-library/current-and-future-generation/fast-neutron-reactors.aspx.
[49] Natrium is expected to have an economic lifetime of **[Begin Confidential]** [redacted] **[End Confidential].**

operational by 2028. The IRP included no discussion of the risks and uncertainties associated with Natrium construction delays, adding to Staff's concerns about the mismatch between the speculative nature of this technology and the influential role it could play in planning and procurement over the next eight years.

<u>Natrium's Inclusion in the Preferred Portfolio</u>
Staff's view is that the Natrium plant should not have been included in the preferred portfolio in 2028. The preferred portfolio, and especially the near-term years, serves as a guide to resource planning. The IRP preferred portfolio should not include a speculative, near-term resource with exceptionally high risks profile for which costs and timing are unknown. In later years of a portfolio, it may make sense to include proxy resources which are not yet common, and which have uncertain cost and risk characteristics.

For reference, the addition of Natrium to the preferred portfolio results in the following changes in GWh of generation through 2028:

[Begin Confidential]
[redacted]

[End Confidential]

The near-term impacts of the Natrium plant on generation and resource acquisition are limited. Before 2026, the addition of the Natrium plant mainly results in **[Begin Confidential]** [redacted] **[End Confidential].** However, in 2026, the inclusion of the Natrium plant displaces one 348 MW solar plus storage project and about **[Begin Confidential]** [redacted] **[End Confidential]** of solar generation.[50] This is within the timeline for acquisitions in the 2022 RFP, so the inclusion of Natrium in this IRP will likely result in reduced resource acquisition from renewable resources, and potentially also from long-lead time resources like pumped hydro storage.

Staff encourages PacifiCorp to evaluate near-term alternatives to Natrium that are not as risky, and Staff continues to support the comparison of the costs and benefits of offshore wind to those of the Natrium plant. As CUB mentioned in Opening Comments, it is not yet possible to

[50] PacifiCorp 2021 IRP. Page 279.

determine what portion of the Natrium plant may be allocated to Oregon, since the PacifiCorp cost allocation process for 2024 and beyond is currently under Multi-State Protocol negotiations. Oregon will remove the costs and benefits of coal generation from its allocation of electricity by 2030 pursuant to SB 1547, and it is not yet clear to what extent various resources from the IRP such as Natrium may replace the costs and benefits of those coal plants may be replaced with.

Recommendations:

Recommendation 12: Staff recommends acknowledging the preferred portfolio and Action Plan only to the extent that they are consistent with the no-Natrium scenario.

Recommendation 13: Staff recommends a Commission workshop at least one month in advance of the 2022 AS RFP Final Shortlist for stakeholders, PacifiCorp, and Commissioners to discuss potential benefits of acquiring additional near-term supply or demand side capacity, including in the 2022 RFP, to help reduce future resource allocation risk for Oregon.

<u>Natrium Plant Procurement</u>

PacifiCorp's IRP and Reply Comments indicate that the Company will pursue the Natrium plant outside of an RFP process. PAC notes in its Action Plan that it will finalize commercial agreements for the Natrium project by the end of 2022.[51] PAC also specifically mentions the possibility of pursuing the resource under an exception to the competitive bidding rules – OAR860-089-0100(3) – which provides an exception to the rules in the case that "[a]n alternative acquisition method was proposed by the electric company in the IRP and explicitly acknowledged by the Commission."[52]

In its Opening Comments, Staff explained that it may have trouble recommending acknowledgement of Natrium in the 2021 IRP because of the lack of detail provided in the IRP and the uncertainty around whether the costs and risks modeled are accurate.[53] Staff continues to have concerns about the Natrium plant and recommends the Commission not acknowledge any action items that Commit PacifiCorp to the Natrium plant as part of the 2021 IRP.

Further, Staff recommends that if PacifiCorp wants to procure the Natrium plant, the Company should include it in an RFP process under the competitive bidding rules. The level of detail provided and considered on projects in the RFP process along with the competitive nature of the process can bring to light further details on the project and allow for better consideration of whether it is a least cost, least risk project compared with other non-emitting, dispatchable, long-duration resources like utility-scale geothermal, pumped hydro projects, and 100 percent renewable hydrogen combustion generation.

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[51] PacifiCorp's 2021 Integrated Resource Plan. Chapter 10. Page 323.
[52] PacifiCorp's Reply Comments. Page 65.
[53] Staff's Opening Comments. Page 10.

Recommendation:

Recommendation 14: Regarding the Natrium plant, PacifiCorp should not pursue an alternative acquisition method but may include the plant as a part of a competitive RFP where it can compete against other resources providing similar types of services.

Hydrogen

The non-emitting peaker plant in the 2021 IRP was based on a green hydrogen peaker.[54] In the 2023 IRP lead-up process, Staff will work with PacifiCorp to improve understanding of the hydrogen resource economics for Staff and stakeholders. Staff is also interested in potentially including a wider variety of potential hydrogen options, including strategic planning around hydrogen load. Staff requests that PacifiCorp and stakeholders provide any responses to Staff's Opening Comments on incorporating flexible hydrogen load onto PacifiCorp's system in their Reply Comments.

Before the PacifiCorp IRP meeting to discuss supply side resources in early 2022, Staff would like to have a discussion with interested stakeholders regarding ways to better model hydrogen resources in the 2023 IRP, as well as the potential to develop tariffs that encourage hydrogen load to generate at times and locations that benefit the system. Staff will convene a brief Oregon stakeholder conference and encourages stakeholders to come prepared with thoughts and suggestions.

Recommendations:

Recommendation 15: In Reply Comments, PacifiCorp should provide responses to Staff's thoughts on incorporating flexible hydrogen load onto PacifiCorp's system.

Recommendation 16: Before the PacifiCorp IRP meeting to discuss supply side resources in early 2022, Staff will convene a brief Oregon stakeholder conference to discuss ways to model hydrogen resources in the 2023 IRP and potential tariffs to encourage hydrogen load generation timed and located in ways that benefit the system.

Offshore Wind

In Opening Comments, Staff requested PacifiCorp perform a sensitivity around offshore wind (OSW) that requires between 500 and 1000 MW of OSW to be added in 2028 or 2030 and allows for endogenous selection of the B2H transmission line, the 2028 Natrium nuclear plant, and the 2022 AS RFP bids. This sensitivity would be designed as a check on the decision to acknowledge the RFP Final Shortlist and would be considered a "bare minimum" for evaluating this technology on a consistent and comparable basis. If the addition of OSW was shown to have the potential to reduce costs by a large amount, then the acknowledgement decision

[54] PacifiCorp's response to Staff DR 096.

could be informed by a discussion of the costs and benefits of potentially delaying 2022 AS RFP resource actions in favor of pursuing OSW resources.

PacifiCorp has indicated that the Company is open to discussing OSW and to potentially including it as a resource option in the 2023 IRP. Given that the 2023 IRP will be completed and filed in March of 2023, and that the 2022 AS RFP Final Shortlist is expected to be filed in June of 2023, it seems possible that a study of Offshore Wind could be used to inform the Final Shortlist acknowledgement decision. [55]

While working toward the consideration of OSW in the 2023 IRP and as a sensitivity in the 2022 AS RFP (UM 2193), Staff requests PacifiCorp conduct a stakeholder feedback process to determine what source the OSW cost data will be based on, with consideration for public data such as the 2021 U.S. DOE Offshore Wind Market Report.[56] Additionally, Staff requests that an analysis considering the development of OSW in comparison to resources associated with the Final Shortlist be published with the Final Shortlist in the 2022 AS RFP. Staff maintains that the sensitivity requested by Staff in Opening Comments would be a good starting point for discussion on what this analysis could look like.

An additional recommendation to further inform discussions around offshore wind is that PacifiCorp should engage with PacifiCorp Transmission prior to the 2023 IRP to request a power flow study of the addition of OSW near Brookings, Oregon to inform what upgrades or enhancements might be needed to interconnect 500 MW to 1,000 MW at this location. Staff requests a conversation with stakeholders in advance of any power flow study to decide on an appropriate amount of OSW to model at each substation in the Brookings area.

Recommendations:

Recommendation 17: PacifiCorp should conduct a stakeholder feedback process to determine what source the Offshore Wind cost data in the 2023 IRP will be based on, with consideration for public data such as the 2021 U.S. DOE Offshore Wind Market Report.

Recommendation 18: PacifiCorp should conduct an analysis akin to the sensitivity Staff proposed in Opening Comments that considers the development of Offshore Wind in comparison to resources associated with the 2022 AS RFP Final Shortlist and publish the analysis with the 2022 AS RFP Final Short List.

Recommendation 19: After a conversation with Staff and stakeholders, PacifiCorp should engage with PacifiCorp Transmission prior to the 2023 IRP to request a power flow study of

[55] Docket No. 2193. PacifiCorp Draft RFP. Page 2.
[56] U.S. Department of Energy, Office of Energy Efficiency & renewable Energy, "Offshore Wind Market Report: 2021 Edition." https://www.energy.gov/sites/default/files/2021-08/Offshore%20Wind%20Market%20Report%202021%20Edition_Final.pdf

the addition of Offshore Wind near Brookings, Oregon to inform what upgrades or enhancements might be needed to interconnect 500 MW to 1,000 MW at this location.

Oregon Qualifying Facility (QF) Projects Completing Cluster Study

Across PacifiCorp's transition cluster and first cluster study there are seven large Oregon solar and solar + storage QF projects that have favorable characteristics and commercial operation dates. Staff finds including these projects in the potential supply-side proxy resource list compelling, given location and the timing of PacifiCorp's capacity needs. This is especially true when considering the cost of competing out-of-state generation and transmission. Notwithstanding, these projects do not appear to have been considered in PacifiCorp's IRP as potential supply side resources. Below is a table that captures the characteristics and potential timing of these projects:

Table 4: Oregon QF Projects in Cluster Studies

Cluster Study	Cluster	County	Type	Size (MW)	Sum. / Wntr CF	Cluster Upgrade Cost $	Months to Complete
Transition	CA8	Crook	Solar + Storage	40 + 40	82% / 93%	$4.6 M	36
Transition	CA8	Crook	Solar + Storage	80 + 80	82% / 93%	$10.6 M	36
Transition	CA8	Crook	Solar + Storage	40 + 40	82% / 93%	$5.4 M	36
Transition	CA8	Crook	Solar	20	13% / 18%	$2.7 M	36
Transition	CA8	Crook	Solar	20	13% / 18%	$5.5 M	36
Transition	CA8	Crook	Solar + Storage	40 + 40	82% / 93%	$7.3 M	36
First	CA11	Linn	Solar + Storage	199 + 150	? % / ? %	$11.2 M	24
Total				439 + 350		$ 47.3M	

In terms of cost, ratepayers are only required to pay for the MWh production of these QF projects. Because each of these projects are larger than 3 MW, the pricing and terms and conditions fall outside the PURPA standard contract terms and avoided cost pricing. This allows for PacifiCorp to explore customized terms with these projects and the opportunity to negotiate an avoided cost price that can approach the average seen in the last RFP. Further, the associated interconnection costs (i.e, station equipment, network, and interconnection facilities) are either competitive or superior on an upgrade cost/MW installed basis to the projects selected in PacifiCorp's two most recent RFPs, reflecting that overall, the economics of these projects could be favorable.

In terms of location, these projects have several benefits. They qualify as community-based renewable energy, which will have increasing importance under HB 2021. They do not require interstate transmission to serve Oregon load and may offset the need for out-of-state imports. The Crook County projects are in a load pocket with an increasing demand due to the data centers in Prineville. The Linn County project is located in the Willamette Valley, an area with steady growth. Finally, all of the projects could be on-line within 36 months.

In summary:

- There are over 400 MW of solar in Oregon paired with approximately 300+ MW of battery storage. The solar + storage projects provide a higher seasonal capacity contribution to the PacifiCorp grid than all proxy-wind projects analyzed by the IRP.
- They are capable of being online in 36 months or less, which helps meets near-term capacity needs and potentially reduces the size of 2022 AS RFP.
- Interconnection costs are known and on a cost per MW installed basis, are comparable or superior to the cost to interconnect and build transmission for renewables associated with EGS or the Aeolus transmission upgrades.
- There is a potential to negotiate lower $/MWh avoided costs due to size of projects, thus making them competitive resources.
- All 400+ MW qualify as community-based renewable energy under HB 2021, better aligning PacifiCorp with Oregon energy policy.
- These were not included in IRP analysis as a supply side resource despite beneficial characteristics to Oregon ratepayers and PacifiCorp system.

Recommendation:

Recommendation 20: Regarding these Oregon QF projects, re-run the IRP model using the solar or solar + storage proxy costs and CF values for these QFs, including identified interconnection costs, to see how these QF resources compete in the model, if they are selected, and their impact this IRP's other resource selections.

Recommendation 21: Much like offshore wind, Staff requests that an analysis considering the development of these projects in comparison to resources associated with the Final Shortlist be published with the Final Shortlist in the 2022 AS RFP.

Recommendation 22: Depending on the outcome of UM 2032 and based on the benefits of the seven Oregon QF cluster study projects, provide a report on the impact of ratepayers covering some or all of the Network Upgrade costs and negotiating terms with these projects so they can be brought online before 2026 to serve customer demand identified in the IRP.

Supply Side Resource Cost and Location

Inaccuracy of Supply Side Resource Reporting and Assumptions

The Supply Side Resource Table (SSR Table) in the 2021 IRP is in several places inaccurate and misleading. For example, the IRP document states that solar plus storage is modeled with storage at 50 percent of the capacity of the solar, and the SST reflects this.[57] However, the Company's response to discovery explains that storage was modeled as 100 percent of the

[57] PacifiCorp's 2021 Integrated Resource Plan. Page 191.

paired solar capacity. [58] Additionally, the IRP states that the capital costs of solar plus storage are about $2,890/kW, while the SSR Table lists them at about $2,300/kW.[59,60] Other SSR Table errors and omissions can be found when comparing the table to actual costs modeled in Plexos.

Staff finds it profoundly difficult to evaluate the IRP when the information provided is inconsistent or erroneous. In order for Staff and Stakeholders to conduct timely, efficient, and accurate analysis, PacifiCorp must provide correct and consistent information in the IRP document.

Recommendation:

Recommendation 23: For the 2023 IRP, PacifiCorp should take steps necessary to provide complete and accurate information in the IRP document that reflects actual IRP modeling assumptions.

<u>**Storage Costs in PacifiCorp's IRP Modeling**</u>

In addition to apparent typos in the SSR Table, stakeholders have pointed out in Opening Comments that PacifiCorp's modeled storage base capital cost is substantially larger than the base capital cost published in NREL's 2021 Annual Technology Baseline (ATB) report. Staff has confirmed that PacifiCorp's storage estimates differ substantially from NREL estimates. This is a concern that PacifiCorp did not adequately address in reply comments, except to say that the IRP cost trajectory for storage decreases faster from 2021 to 2024 to account for declining costs.

Recommendation:

Recommendation 24: In the 2023 IRP, PacifiCorp's storage costs should be in line with the most recent NREL ATB report and most recent RFP Final Shortlist before publishing the Supply Side Table.

<u>**Additional Information of Use to Stakeholders and RFP Bidders**</u>

Additional information about supply side resources could be helpful to Staff and stakeholders, while reducing costs by promoting competition in resource procurement. Staff would like to see prominently placed information in future IRPs about the location and timing of energy and capacity need on PacifiCorp's system so that project developers can submit the most informed bids possible. This should include a clear map of what resources were selected each year in each location on PacifiCorp's system. This was included in Appendix M with the 2019 IRP, but not included with the 2021 IRP. Staff found this resource valuable and it could also be used by bidders to anticipate system needs. Staff would appreciate if such a map could be included with the Executive Summary of the IRP.

[58] PacifiCorp's Response to Sierra Club DR 1.6
[59] PacifiCorp's 2021 IRP. Page 179.
[60] PacifiCorp's 2021 IRP. Page 270.

Additionally, potential RFP bidders should be given access to a 12x24 Loss of Load Probability matrix for one out of every five years in the IRP planning timeframe, either during the IRP or during the RFP process.

Recommendations:

Recommendation 25: The 2023 IRP executive summary should include a map of resources added in the preferred portfolio by year and location.

Recommendation 26: In future IRPs or during future RFP processes, potential RFP bidders should be given access to a 12x24 Loss of Load Probability matrix for one out of every five years in the IRP planning timeframe.

Reliability Resources

The Plexos model consists of Short-Term (ST), Medium-Term (MT), and Long-Term (LT) modeling steps. After running each of these modeling steps, PacifiCorp's modeling process includes an additional step in which the IRP team hand-selects and adds a set of reliability resources to each portfolio. This step is important because the more granular ST model is able to identify resource needs that were not identified in the initial LT capacity expansion model run.

Regarding the Jim Bridger 3 and 4 early retirement portfolio, P02h, Sierra Club has pointed out that PacifiCorp's choice of a nuclear plant as a reliability resource in the sensitivity with early retirement at Bridger 3 and 4 lacked transparency and supporting analysis.[61] Staff agrees that this selection was unsupported in the IRP and could have been sub-optimal.

Staff is concerned that the reliability resource process in the 2021 IRP significantly increased the amount of risk in the preferred portfolio and other portfolios by adding nuclear proxy resources. Staff is concerned that the addition of a nuclear resource introduces unnecessary risk to customers, especially if a resource such as a pumped hydro storage facility or flow storage battery would have been adequate to meet the reliability need.

Staff understands that a reliability adjustment may be needed, but the level of transparency around the reliability step and how reliability resources are selected has been disappointing in this IRP.

[61] Sierra Club Opening Comments. Page 22.

Recommendations:

Recommendation 27: In the 2023 IRP, PacifiCorp should clearly explain the reliability limitations of the LT capacity expansion model, and how the IRP team selected the reliability resources to add to the ST model.

Recommendation 28: The 2023 IRP workpapers should include a report of the timing and duration of reliability events from the ST run that necessitated the addition of reliability resources in each portfolio.

Planning Reserve Margin

Sierra Club expressed concern about the 13 percent planning reserve margin (PRM) included in the 2021 IRP modeling for each location on the system. Staff has submitted a DR to PacifiCorp and received a response stating that while there is a planning reserve margin at each location, the 13 percent PRM requirement can be met with resources from any location, as long as transmission is available. [62]

The use of a locational PRM in Plexos is surprising to Staff, given that Plexos is capable of modeling reserve requirements and stochastic risks. Staff requests that the need for a PRM in Plexos can be a topic at the February 24, 2022, Commission Workshop if time allows.

Pumped Hydro Storage

Swan Lake's Opening Comments argue that, although pumped hydro storage (PHS) projects tend to be less expensive than li-ion batteries in PacifiCorp's Supply Side Resource Table, PHS projects are not included in the preferred portfolio until 2040. Swan Lake also provides a report with cost data on different types of long-duration storage.

For reference, below is a table of the costs of li-ion and PHS projects in PacifiCorp's Supply Side Table (SST).

Table 5: costs of li-ion and PHS projects in PacifiCorp's Supply Side Table (SST)

Fuel	Resource	Net Capacity (MW)	Commercial Operation Year	Design Life (yr	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-y	Demolition Cost ($/kW)
Storage	Li-Ion Battery, , 1 MW, 0.5 MWh	1	2023	20	1,948	Included in FOM	40.00	55.00
Storage	Li-Ion Battery, , 1 MW, 1 MWh	1	2023	20	2,058	Included in FOM	50.00	110.00
Storage	Li-Ion Battery, , 1 MW, 4 MWh	1	2023	20	3,167	Included in FOM	70.00	440.00
Storage	Li-Ion Battery, , 1 MW, 8 MWh	1	2023	20	4,622	Included in FOM	100.00	880.00
Storage	Li-Ion Battery, , 50 MW, 200 MWh	50	2023	20	1,820	Included in FOM	27.60	440.00
Storage	Pumped Hydro, Badger Mountain	500	2027	80	2,621	0.37	28.00	485.00
Storage	Pumped Hydro, Banner Mountain	400	2028	50	3,276	0.00	28.50	485.00
Storage	Pumped Hydro, Flat Canyon	300	2029	80	4,046	0.37	53.33	485.00
Storage	Pumped Hydro, Goldendale	1,200	2028	60	2,833	0.00	12.50	485.00
Storage	Pumped Hydro, Gordon Butte	400	2027	80	7,801	0.37	22.00	485.00
Storage	Pumped Hydro, Owyhee	600	2029	80	3,203	0.37	20.00	485.00
Storage	Pumped Hydro, Seminoe	750	2029	80	3,461	0.37	16.00	485.00
Storage	Pumped Hydro, Swan Lake	400	2027	60	3,095	0.00	12.50	485.00
Storage	Pumped Hydro, Utah PS2	500	2027	80	3,237	0.37	28.00	485.00
Storage	Pumped Hydro, Utah PS3	600	2029	80	3,371	0.37	20.00	485.00

[62] PacifiCorp Reply to Staff DR 104.

Staff notes that the Goldendale project has lower annual fixed O&M costs in $/kW-yr than a 50 MW, 200 MWh Li-ion battery, but also has higher Base Capital costs on a per-kW basis. It is difficult to tell from the data provided in PacifiCorp's SST which resource is the most economic option in a given year. This is especially true since the dollars per kW-yr cost metrics do not account for the fact that PHS typically provides many hours of capacity (12 hours in the case of Goldendale), whereas the lowest cost Li-ion option provides only 4 hours. Thus, the economics of Li-ion versus PHS will depend on what value the Plexos model identifies for dispatchable capacity with more than four hours of dispatch. This may vary in different years of the planning timeframe.

For reference, the confidential table below shows the acquisitions of flexible capacity resources in the preferred portfolio by year, and demonstrates that most Li-ion resources are included as part of a hybrid resource with solar.

[Begin Confidential]

[redacted]

[End Confidential]

Additionally, Staff finds Swan Lake's argument that PHS can help reduce risk on the system by diversifying resources to be important. The preferred portfolio includes over **[Begin Confidential**] [redacted] **[End Confidential]** of Li-ion batteries before 2040, and only about **[Begin Confidential**] [redacted] **[End Confidential**] of other dispatchable resources, including molten salt storage and flexible hydrogen peakers. The risks of such heavy reliance on Li-ion batteries are not adequately accounted for in the IRP modeling. Li-ion batteries are an emerging technology on the utility-scale. If there is a performance issue with utility-scale Li-ion batteries that is not anticipated, or if any other downside risk prevails with respect to Li-ion, it would be valuable to customers to have a diversified portfolio with adequate flexible capacity that is not subject to the same risks.

Additionally, Swan Lake states that the IRP assumptions about PHS are outdated and inaccurate, and that PacifiCorp should re-run its IRP model using updated cost assumptions for PHS. Staff agrees.

Finally, Staff would note the disconnect between the position of the Swan Lake pumped hydro in PacifiCorp's IRP and the preliminary permit the company itself has requested for pumped hydro that it would own in Lake County. Per Oregon Public Broadcasting,

> The company has proposed building a 52-acre upper reservoir and 50-acre lower reservoir, powerhouse and pump station, plus nearly a 20-mile transmission line connecting the system to a substation in Lakeview...If built, the Crooked Creek pumped hydro project could generate 1,460 GWH annually.[63]

The Swan Lake project is further along in the environmental, project, and transmission permitting process than the proposed Crooked Creek project, although somewhat smaller in size and different in ownership model.[64] More importantly, Swan Lake should also be operational by 2026, and capable of providing upwards of nearly 1.2 GWH from a dispatchable capacity resource annually, which could immediately contribute towards PacifiCorp's capacity deficit.

It would appear the economics of pumped hydro are compelling enough for PacifiCorp to begin exploring ownership of a project 20 percent bigger than Swan Lake in southern Oregon. However, the supply-side resource table 7.1 in Section 7 of the IRP did not include Crooked Creek. Staff is concerned about a bias toward utility-owned pumped hydro in PacifiCorp's planning.

In addition to re-running the IRP model using updated cost assumptions for PHS, Staff would request two additional things: First, PacifiCorp should discuss and compare the transmission and operational constraints faced by Swan Lake relative to the proposed Crooked Creek in its final IRP comments. Second, as part of the 2023 IRP public workshop series, the Company should review the pumped hydro project proposals PacifiCorp is considering, regardless of ownership model. It should also detail the potential benefits of pumped hydro in an era of decarbonization, including the reliability benefits of adding more than one project to its

[63] OPB Science & Environment. "PacifiCorp eyes pumped storage hydropower project in Southern Oregon," Jan. 10, 2022.

[64] Regarding environmental permits *see* the Federal Permitting dashboard Swan Lake North Pumped Storage | Permitting Dashboard (performance.gov) FERC issued a license in 2019 inclusive of the 38 mile transmission line to the Malin substation.

portfolio and the benefits of adding mass/inertia from large rotating generators to an increasingly inverter-based portfolio of resources.

Recommendations:

Recommendation 29: PacifiCorp should re-run its IRP model using updated cost assumptions for pumped hydro storage, either as a part of a requested sensitivity to the 2021 IRP, or in the 2023 IRP.

Recommendation 30: PacifiCorp should discuss and compare the transmission and operational constraints faced by Swan Lake relative to the proposed Crooked Creek in its final IRP comments.

Recommendation 31: As part of the 2023 IRP public workshop series, the Company should review the pumped hydro project proposals PacifiCorp is considering and detail the potential benefits of pumped hydro in an era of decarbonization, including the reliability benefits of adding more than one project to its portfolio and the benefits of adding mass/inertia from large rotating generators to an increasingly inverter-based portfolio of resources.

1.1.3 Transmission

In Staff's Opening Comments, Staff posed a series of questions pertaining to Action Plan project details and costs, and the Company's transmission options as modeled in the IRP. Among the questions Staff posed are the following:

1. Staff raised the issue of PacifiCorp's failure to delineate specific projects in Action Item 3d, "Planned Transmission System Improvements."
2. Staff asked whether and how the costs of each transmission and interconnection upgrade in the IRP Action Plan are considered in PLEXOS modeling.
3. Staff raised the issue of PacifiCorp's failure to model Boardman to Hemingway (B2H) and Energy Gateway South (EGS) simultaneously, and refusing to allow the two projects to compete with each other.
4. Staff asked the Company to clarify how Segment D.1 costs were being considered in the IRP, and whether they were assumed to be part of EGS.
5. Staff asked the Company to justify the reasoning behind the $1.4 billion discount for Gateway South connected to the 230 kV line allegedly needed to connect Eastern Wyoming wind to the Clover substation. Staff also asked the Company to provide an explicit delineation of build costs of each of the transmission projects in the Action Plan, with and without any offsets, and narrative of why those offsets were included.

Staff does not believe that the Company sufficiently addressed Staff's questions above.

Planned Transmission System Improvements

Regarding Question 1, the Company has yet to itemize any Action Items in Action Item 3d to initiate Local Reinforcement Projects. This includes Action Items themselves, as well as their costs. In its Reply Comments, PacifiCorp pointed to the RFP and included a vague statement: "The network upgrades were identified in the interconnection study and are required in order to interconnect the final shortlist projects to the transmission system." This response fails to itemize projects in the Action Plan, does not connect it to PLEXOS, and does not give the Commission or stakeholders an adequate understanding of what is being requested in the Action Plan. Further, insofar as some of the activities included in the Action Plan are items already acknowledged elsewhere, Staff is not inclined to submit an additional recommendation regarding acknowledgement.

With respect to local reinforcements, the transmission projects listed on pages 100-103 of Volume I of the 2021 IRP are incremental system improvement projects that PacifiCorp has planned to complete to maintain system reliability and maximize system efficiency. PacifiCorp claims that these are reliability requirements, and thus they do not have a role in resource acquisition and may not be appropriate to include in an Action Plan. It is unclear to Staff what standard the Company is using to categorize projects as "reliability" vs. "resource." Any new resource will need engineering analysis and will need to abide by reliability standards, so it is unclear how PacifiCorp is exercising judgment for the purposes of including a project as part of an Action Item. In the 2023 IRP, PacifiCorp should describe how it delineates between reliability related transmission work, and that which is deemed resource related. The Company should indicate whether each project is reliability or resource related.

Recommendation 32: In the 2023 IRP, PacifiCorp should describe how it delineates between reliability-related transmission system improvements and those which are deemed resource-related. Further, transmission system improvements should be clearly specified as reliability or resource related .

Modeling Costs in PLEXOS

Regarding Staff's Question 2 above, when Staff inquired about the inclusion of Action Plan transmission and interconnection upgrades in the Plexos model, PacifiCorp indicated that "Costs of all transmission and interconnection upgrades are evaluated by the PLEXOS model and weighed against all other options before being selected."[65] However, this still does not clarify matters because PacifiCorp only models transmission rights in PLEXOS, and generally not specific lines. In the past, the Company has also indicated that it uses proxy resources for the IRP for new builds. Staff's question was specifically whether and how *Action Items* were considered in PLEXOS. With the exception of Gateway South, it is unclear whether any specific projects included as part of Action Item 3d were modeled in PLEXOS.

[65] PacifiCorp Reply Comments. Page 58.

With such little information provided in the IRP, Staff does not believe Action Item 3d should be acknowledged (see recommendations in section 2.1 Action Plan Acknowledgement). It is far too vague—specific Action Items are not provided, and neither are their costs or justifications. In Opening Comments, Staff pointed to an example of an adequate data response that NW Natural provided when it wanted acknowledgment for certain distribution projects in its Action Plan. In the next IRP, the Company should strive to provide adequate justification for projects in the Action Plan.

Modeling Boardman to Hemingway with EGS

With respect to Staff's Question 3 above, and the endogenous selection of the B2H transmission line being simultaneously modeled with endogenous selection of EGS, PacifiCorp was unable to respond to Staff.

Staff is aware that there have been recent agreements among Bonneville Power Administration and Idaho Power, termed the "B2H with Transfer Service" agreement in which Idaho Power will take over BPA's ownership share of the line, in addition to some asset exchanges. Staff has reviewed the Term Sheet posted by Idaho Power and has some additional questions for both companies regulated by the Commission. The issue of the asset exchanges is related to PacifiCorp's IRP because it is unclear how this would affect the profitability of B2H, either positively or negatively. Staff is interested in understanding more about the particulars of the new B2H agreement and recommends that there be a joint Idaho Power – PacifiCorp workshop to highlight details about the exchanges.

While the Company has failed to respond to Staff regarding simultaneous modeling of B2H and EGS, it has not requested acknowledgement for the project itself and has limited its Action Item to pre-construction activities. Staff still believes it is reasonable to proceed with pre-construction activities of the B2H project. Similarly, the Company has not requested acknowledgment for Gateway West or Segment D.3. Staff looks forward to hearing more from the Company on B2H developments. Staff recommends the Commission acknowledge Action Item 3c and 3e (see recommendations in section 2.1 Action Plan Acknowledgement).

Costs of Segment D.1

With respect to Question 4, PacifiCorp confirmed in its Reply Comments that D.1 is included as part of the project cost of Gateway South. While Staff understands that interconnecting various wind projects would electrically require a transmission upgrade like D.1, the Company should have been more transparent about the need for this project, separate from EGS, in the IRP.

Gateway South Cost Assumptions in the 2021 IRP

In the 2021 IRP, Gateway South has been modeled in the preferred portfolio as an alternative to a 230 kV line that PacifiCorp maintains the Company would be otherwise required to build because of a Firm, Point-to-point transmission request. The 500 kV Gateway South line is shown by the IRP modeling to be a more cost-effective alternative, given the Company's assertion that it would otherwise be required to build a 230 kV line at a cost of $1.4 billion.[66] In its Opening Comments, Staff asked the Company to produce "a study justifying the 230 kV line said to be needed to connect Eastern Wyoming to Clover."[67] Unfortunately, the Company seems to have misinterpreted Staff's request and provided studies for 230 kV lines that do not connect Wyoming to Utah, but instead provide transmission within Eastern Wyoming.[68] Staff has not yet seen a study that justifies the cost estimate of $1.4 billion for this alternative to Gateway South.

Potential for Alternative Financing of Gateway South

In the closing memo to Docket No. UM 2059, Staff raised the idea of alternative financing for Gateway South. Staff is aware that BPA provides a tariff option where, if a customer's transmission service needs require a new line or expensive new upgrades, BPA will build it, but it is financed through the customer's incremental rates. The idea here is that a customer can choose to pay extra over time to eventually pay back the cost of a transmission upgrade to BPA.

However, Staff is also aware that transmission customers have generally not chosen this alternative financing option. Many times, transmission customers simply do not want to pay extra for transmission service. It is more cost effective for them to lean on the utility and its ratepayers. Unless there is a system-wide benefit, BPA does not build these lines if they cannot be appropriately financed. Thus, even if PacifiCorp wanted to offer incremental rates, customers might not accept them.

In the Final Shortlist acknowledgement Order for the 2020 AS RFP Final Shortlist, the Commission directed PacifiCorp to present to Commissioners within five months of October 12, 2021, a "discussion of the federal-state relationship around transmission decisions and the obligations that transmission providers have under federal law, and if appropriate, alternate financing of future transmission investments."[69] The Commission noted that in acknowledging the Final Shortlist, it relies on PacifiCorp's view of its federal obligation to build transmission, and stated that a prudence review of the project may "include a review of federal transmission obligations (informed by the federal-state discussion we require above), and actual benefits and costs of the project as built, with the opportunity to look at aspects like HB 2021 compliance, increased reliability, and diversified resources."[70]

Staff looks forward to the transmission discussion in the Company's 2022 AS RFP, currently scheduled for March 8, 2022. While Staff understands that the main topic of the workshop will be a general discussion of federal transmission requirements, Staff also requests that PacifiCorp provide a study demonstrating the specific $1.4 billion in transmission upgrades that would be required in the absence of Gateway South as a part of this conversation. This information will be important during prudence review.

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[66] PacifiCorp 2020 AS RFP. Final Shortlist Sensitivities Presentation of August 5, 2021.
[67] Staff Opening Comments. Page 20
[68] PacifiCorp's Supplemental Response to Staff DR 048.
[69] Order No. 21-437. Page 15.
[70] Order No. 21-437. Page 15.

1.1.6 Resource Adequacy (RA)

RNW notes that the Western Resource Adequacy Program (WRAP) may provide PacifiCorp the opportunity to reduce its IRP Planning Reserve Margin (PRM), since the Company's resource adequacy needs may be reduced through the benefits of geographical diversity.[71] It will be important for the IRP's PRM to be reduced in a way that reflects the benefits of regional resource adequacy planning by reducing costs for customers while maintaining reliability. RNW states, "[t]he details of PacifiCorp's involvement in WRAP are essential in the IRP context and we recommend PacifiCorp provide more clarity as to the data submitted to the WRAP Program Operator in future 2021 IRP-related workshops." Staff supports RNW's recommendation, although Staff would support the discussion of this information in data requests, comments, or a workshop.

Recommendations:

> **Recommendation 33: In Reply Comments, PacifiCorp should provide additional clarity on the data submitted to WRAP Program Operator in the 2021 IRP.**

> **Recommendation 34: In the 2023 IRP, PacifiCorp should be required to clearly show how its IRP Planning Reserve Margin is consistent with any PRM assigned to the Company in the WRAP process. Any deviation from the WRAP PRM should be thoroughly explained and justified.**

1.1.7 DSM, Conservation, and Demand Response

Demand Side Management (DSM): Efficiency and Demand Response

Staff appreciates the conversation around demand response and efficiency in the 2021 IRP and comments. In Opening Comments, Staff was supportive of the capacity-based DSM bundling methodology, but also expressed concern about the 2021 IRP's selection of less near-term efficiency than the 2019 IRP.[72] PacifiCorp's reply comments stated that the capacity-based bundling of efficiency can result in more cost-effective acquisition of efficiency at times when it is most needed (when it is providing the most capacity), while reducing the number of MWh of overall efficiency. PacifiCorp notes that Oregon's efficiency in the IRP equals 81 percent of the technical achievable efficiency potential in Oregon.

Staff appreciates the Company's explanation regarding efficiency in the IRP. Staff understands that efficiency can potentially provide value at a lower cost when it is selected based on capacity contribution during hours with high LOLP.

Efficiency's Role in Reducing Resource Allocation Risk

Staff is concerned about resource allocation risk attributable to the unsettled nature of the Multi-State Protocol cost-allocation process after 2023. It is possible that Oregon may receive a

[71] RNW Opening Comments. Page 11.

[72] Staff Opening Comments. Pages 30 – 32.

disproportionate share of some of the costs and risks of new supply-side resources entering the system before 2030, as Oregon exits coal units. The uncertainty around cost allocation makes the assessment of the costs and risks of supply side resources in the preferred portfolio more difficult. The risk to Oregon customers associated with the preferred portfolio increases because Commissioners must decide whether to acknowledge the preferred portfolio without knowing how supply-side costs will be allocated among states. If Oregon ultimately receives disproportionate amount of any given resource, that resource's unique risk profile will potentially impact Oregon ratepayers in a harmful way.

Efficiency may have a role to play in reducing this resource allocation risk for Oregon customers. Efficiency is a local resource that reduces emissions. In addition, the 2020 MSP has established that efficiency investments will be situs-allocated to the state in which the efficiency is located.[73] This provides certainty about the costs and risks of efficiency investments, providing a knowable risk in comparison to supply-side resources.

Staff would like to begin exploring the potential to increase Oregon's acquisition of near-term efficiency and demand response in order to reduce Oregon's capacity need and the associated supply-side resource allocation risk.

Recommendation 35: Staff recommends a Commission workshop to discuss potential ways to increase efficiency and demand response to decrease resource allocation risk for Oregon customers, including but not limited to consideration of a new or updated risk-reduction credit to efficiency.

Demand Side Management : Class 3 and Portfolio Development

PacifiCorp defines Class 3 DSM as price response and load shifting programs that seek to achieve short-duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal. These include such offerings as time of use, time of day, critical peak pricing, and peak time rebates. Generally, Class 3 DSM plays little to no role in the PacifiCorp 2021 IRP resource supply and selection. The composition of DSM across LC 77's initial portfolios appears entirely comprised of demand response programs (Class 1) and energy efficiency (Class 2).[74] This may be due to the limited Class 3 offerings and low levels of participation.[75] In Oregon, just over 0.01 percent of all residential customers participate in the Company's only residential Class 3 offering, the time of use (TOU) rate.

[73] Order 20-024. Appendix B. Page 3.
[74] *See* LC 77, 2021 IRP Filing, Figure 9.4 "Initial Portfolios DSM Resources," page 259.
[75] *See* PacifiCorp reply to OPUC Staff DR 87, Jan. 4, 2022

Table 7: Demand-Side Management Participation

Demand-Side Management (DSM)

Class 3 Pilots

Program	State	Schedule #	Participants as 9/1/2021	Total Eligible
Residential Time of Use	Oregon	6	67	517,740
Non-Residential Time of Use	Oregon	29	-	94,264
Interruptible Service	Oregon	218	-	195
Residential Time of Use	Washington	19	4	107,790
Non-Residential Time of Use	Washington	29	-	21,005
Irrigation Time of Use	Washington	40	-	5,136
Residential Electric Vehicle Time of Use	Utah	2E	464	unknown
Residential Time of Use	Wyoming	19	1	116,741
Non-Residential Time of Use	Wyoming	29	-	28,106
Irrigation Time of Use	Wyoming	40 & 210	1	870
Interruptible Service	Wyoming	30	-	100
Real-Time Day Ahead Pricing	Wyoming	31	-	100

[76]

Staff would note that the lack of participation, and thus almost no resource availability, stands in stark contrast to Portland General Electric's (PGE) two price response residential DSM offerings: Peak Time Rebates and Time of Day.

First, PGE's Peak-Time Rebate (a.k.a., Flex 2.0) forecasts enrolling approximately 140,000 customers in 2023.[77] And in terms of grid impacts PGE's two residential Class 3 DSM programs are slated to reduce PGE's 2023 summer peak by about 1 percent.

Table 8: PGE Peak Time Rebate 2023 Load Impact Goals

	2023 load impact goal (MW)	
	Summer	Winter
Existing pilots/programs		
Residential Peak Time Rebates	22.4	16.8
Residential Time of Day	4.8	2.2
Residential Smart Thermostat	39.9	9.7
Energy Partner Demand Response	30.5	27
Energy Partner Smart Thermostat	1.8	1.1
Multifamily Water Heating	6.8	10.2
Portfolio total	106.2	67

[78]

In response to Staff's questions regarding the development of a peak time rebate, PacifiCorp stated that they have, "... not specifically evaluated whether it should offer such a program. It would not be able to do so until after it replaces its billing system in the mid-2020s."[79]

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[76] *Ibid.*

[77] *See* UM 2141, PGE Flexible Load Multi-Year Plan 2022-2023, Nov. 3, 2021, page 80.

[78] *See* UM 2141, Staff's Public Meeting Memo, Jan. 19, 2022, Table 2, page 5.

[79] *See* LC 77, PacifiCorp's Reply Comments, Dec. 23, 2021, page 43.

First, Staff's recent experience with PGE would point to the lack of a credible Class 3 DSM offering from PacifiCorp as having less to do with the billing system and more to do with a desire to explore options. Independent of PacifiCorp's billing system, the Company has charged ratepayers over $112 million for a brand-new, advanced metering infrastructure (AMI) system with $2.5 million in annual O&M that is capable of enabling such a program.[80] Per the benefits touted in PacifiCorp testimony, the project's $79.4 million in meters, $25.5 million in IT upgrades, and $7.2 million in customer service software "...[create] a platform for smart grid modernization allowing PacifiCorp increased visibility into the electrical network and customer interface to assist in future programs and investments."[81] However, this platform is not being utilized for a simple peak time rebate program that is clearly succeeding at an adjacent utility. Peak time rebate programs regularly work with trusted vendors to safely use AMI data to assess rebates when the utility's billing systems are too antiquated, like PacifiCorp claims theirs is. Additionally, utilities can utilize email for day-ahead events if SMS systems cannot be used to notify participants of upcoming peak-time rebate events.

Second, Staff's experience with PGE also points to Class 3 DSM offering achieving real savings, not just shifting load, and a high degree of customer satisfaction and ongoing participation.

Finally, Class 3 DSM falls under the rubric of demand response. PacifiCorp's reluctance to develop a Class 3 DSM offering until the mid-2020's is not only out of step with their recent good work in developing Class 1 Demand Response programs, but also with the law. ORS 757.054 calls for PacifiCorp to plan for and pursue the acquisition of available cost-effective demand response resources before acquiring new generating resources.

PacifiCorp needs to get moving on Class 3 DSM offerings. The Company has spent million on new meters infrastructure but will not harness the resulting data to effectively engage with their customers on Class 3 DSM programs we have seen be successful elsewhere.

Recommendation 36: Before the next IRP, PacifiCorp should hire a consulting firm to help PacifiCorp staff design a Peak-Time Rebate program for Oregon. In their work, the consultant should benchmark best practices from the most impactful programs by other utilities and suggest Class 3 DSM designs capable of working with PacifiCorp's existing AMI, billing, and customer communication systems. The Company should present the consultant's findings to an IRP stakeholder workshop prior to filing the next IRP.

Section 2: Moving Forward

[80] UE 374, Opening Testimony, PAC/1100, Lucas/27.
[81] UE 374, Opening Testimony, PAC/1100, Lucas/28.

2.1 Action Plan Acknowledgement

To summarize Staff's recommendations regarding Action Items, Staff recommends the Commission acknowledge all Action Items except:

- Item 2c: While the majority of the elements of Action Item 2c seem reasonable, the item to "finalize commercial agreements for the Natrium™ project" seems to have the potential to commit the Company to future actions other than those within the Action Plan. Generally, it is unclear what the nature of these "commercial agreements" will be, and for this reason Staff does not recommend acknowledgement of this aspect of Item 2c.
- Items 3a and 3b – Items 3a and 3b to construct Energy Gateway South and the D.1 line have been discussed in great depth in the 2019 IRP and the PacifiCorp 2020AS RFP. The Commission has a plan to continue the conversation around these transmission investments and Staff does not recommend acknowledgement of these items in the 2022 IRP.
- Item 3d: This Action item is vague. Specific Action Items are not provided, and neither are their costs or justifications.

Recommendation 37: Acknowledge all action items except the element of item 2c to "finalize commercial agreements" for Natrium, items 3a and 3b because they have been discussed at length in previous dockets, and 3d because it is vague and insufficient supporting data has been provided.

2.2 HB 2021 Compatibility

Staff and stakeholders expressed views on the current IRP's consistency with HB 2021 in opening comments. GEI and RNW argued that PacifiCorp should not delay acquiring emissions-free technology. In response to HB 2021 concerns, PacifiCorp notes that the 2021 IRP indicates the Company appears to be on track to meet 2030 target and will work with stakeholders in the leadup to the 2023 IRP.[82]

Additionally, GEI wrote that while HB 2021 says that PacifiCorp may engage with an Advisory Group, the Commission should treat this recommendation as a directive, and that participants in the IRP process should be provided access to technical experts if they have questions. PacifiCorp's Reply Comments stated that the Company is planning on forming an Advisory Group, and Staff is supportive of this important step.[83] Staff agrees that providing access to technical experts will be an important part of implementing HB 2021.

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[82] PacifiCorp Reply Comments. Page 80.
[83] PacifiCorp Reply Comments. Page 80.

2.2.2 Planned Investments & Questions

In response to Staff questions about the reasonableness of PacifiCorp's plan to initiate two RFPs before filing a Clean Energy Plan pursuant to HB 2021, PacifiCorp explained the Company's view that, as long as an IRP is acknowledged before the filing of the Final Shortlist in an RFP, the Commission can be informed by both the acknowledged IRP and the RFP proceeding, which both utilize the same portfolio optimization model with the difference that the RFP utilizes actual near-term resource costs.[84] However, it is still disappointing that the 2021 IRP did not contain a discussion of how close the Company might be to meeting the HB 2021 targets, especially in light of the 2021 AS RFP 1.4 MW of new generation, 600 MW of storage, and over 600 miles of new transmission. In Staff's view, a potential opportunity to set the stage for 2023 IRP conversations was missed.

Staff understands PacifiCorp's point to mean that, while a 2023 RFP would be the second RFP *initiated* before the filing of a CEP, the final shortlist acknowledgment decision in a 2023 IRP could be informed by a Clean Energy Plan filed in late 2023 or even 2024. Thus, according to PacifiCorp, there would only be one RFP – the 2021 AS RFP, UM 2193 – completed after the signing of HB 2021 that was uninformed by a Clean Energy Plan. However, this downplays the potential impact that IRP analysis, and thus a CEP analysis, could have on the scope and orientation of an RFP.

For example, two 100 percent clean analyses reviewed by Staff point to a modeling orientation around the end-goal. In essence, the IRP Action Plan timeframe is no longer the next four years, but rather the remaining years to meet the state policy targets. This approach appears to place a premium on near- to medium-term investments that might not be optimized by current portfolio modeling. Should the Commission choose to reframe the next Action Plan window from four to seventeen years (I.e., 2023-to-2027 vs 2023-to-2040) as part of the 2023 IRP, a contemporaneous RFP would risk being out of step with the IRP and CEP.

Rather than providing forecast Oregon-allocated emissions and providing more insight into how the Company plans to meet HB 2021, PacifiCorp's Reply Comments explained that HB 2021 will be discussed as part of a stakeholder process leading up to the 2023 IRP, including work with an Advisory Group.[85] However, the scope of the Advisory Group is unknown at this point and PacifiCorp is under no obligation to engage the Advisory Group in the development of the Clean Energy Plan itself, only to produce a biennial report in consultation with the Advisory Group to assess the community benefits and impacts of the CEP.[86]

Staff understands that certain aspects of HB 2021 planning will need to be discussed with stakeholders and framed before implementation, most notably in UM 2225. Staff looks forward to exploring the scope of the CEP and the relationship to IRPs and RFPs with the Company and other stakeholders.

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[84] PacifiCorp Reply Comments. Page 66.

[85] PacifiCorp Reply Comments. Page 79-80.

[86] *See* HB 2021-Enrolled, Section 6, page 4-5.

2.3 2022 AS RFP

2.3.1 Risk and Resource Acquisition

Power Purchase Agreements (PPA) Versus Utility Ownership

In Opening Comments, Staff argued that including PPAs along with utility-owned resources can provide valuable risk-reduction to ratepayers through diversification and through the reduced exposure to generator performance issues in a PPA.[59] Staff continues to support diversity of resource ownership and would expect outcomes that include such diversity. Staff expects PacifiCorp to address ownership diversity and risks in its derivation of any RFP shortlist.

Recommendation 38: PacifiCorp address ownership diversity and risks in its derivation of future RFP shortlists.

2.3.2 Scoring and Modeling

Staff notes that, although a bid scoring appendix was included with the 2021 IRP, PacifiCorp has since filed its 2021 AS RFP with an updated bid scoring methodology. Staff has not reviewed the bid scoring methodology filed with the 2021 IRP and does not recommend acknowledgment of this methodology, simply because it is not the most up to date version.

Section 3: Compliance Items

3.1 2019 IRP Compliance with Order 20-186

3.1.1 QF Renewals

In Opening Comments, Staff asked "that the Company model QF renewals and explain the impact of these renewals on its load resource balance." PAC responded that it instead "opted to provide an explanation."[87] Accurately forecasting QFs is a significant issue because it affects the Company's resource need position. In the last several IRPs, QFs have been modeled as not renewing after contract expiration. Generally, Staff finds it appropriate to assume some reasonable amount of QF renewals in the IRP, since historically the renewal rate has been non-zero.

For the next IRP, Staff recommends a two-pronged approach. First, for the long-term forecast, Staff maintains that PacifiCorp should model QF renewals at some reasonable rate. Second, Staff recommends that for the first 4-5 years of the planning horizon, zero QF renewals should be assumed unless the Company has specific knowledge that a QF will renew. This will allow the

[87] PAC's December 23, 2021 Response Comments, page 45.

Company to plan for a reliable near-term Action Plan, while modeling later QF renewals at a reasonable rate.

REC provided extensive Opening Comments on the QF renewal assumption issue. REC recommends requiring that PAC "assume in its IRP that all or a reasonable number of existing QFs will renew their contracts."[88] REC argues that the assumption of no renewing QFs is not reasonable.[89] REC argues that utilities should assume most QFs will renew because transmission charges make it hard to sell to another utility and some QFs can have lifespans of 100 years.[90] REC describes its discussions with PAC in the last IRP that procurement can be delayed by renewing QFs.[91] REC describes the importance of the QF renewal assumptions issue for the compensation of QFs because the IRP assumptions feed into QF pricing.

PAC responded to Staff and REC's arguments. PAC argues that some QFs might not renew because they shut down or sell elsewhere.[92] Although PAC concedes that renewing QFs can lower resource need, "because these QFs are assumed to expire, the development of a reliable portfolio requires slightly more resources than it might if these resources were assumed to continue selling to the Company," it argues that the issue is minor because, "it is likely that the effective contribution of expiring QFs in the first ten years of the Company's analysis is less than 100 MW."[93] PAC argues that compensation issues should be settled in another docket.

PAC's arguments about the risk of actual QF capacity short falling forecasted QF capacity is not as much of an issue in the long term, because in the Company's own words, there is "uncertainty associated with load."[94] For the long term, the Company's expected case should represent the most likely outcome recognizing that actual load can be higher or lower than actual supply. PAC's Response Comments neither agreed with nor specifically disputed REC's assertion that most QFs will renew.

At this time, Staff does not propose a specific QF renewal rate assumption, but recommends that PAC assume some reasonable level of assumed renewals in its next IRP because accurate QF assumptions are needed for accurate long-term planning. The approach used in PGE's QF pricing docket UM 1728 can inform PacifiCorp's QF modeling here.

> PGE will develop QF … renewal sensitivity analyses… for QF renewals, [the Company] will examine factors including but not limited to: the historic percentage of PGE's QFs that have renewed their contracts, the sophistication and experience of project developers, contractual provisions, technology, the opportunity to sell power to other utilities, and interconnection risks. At least one analysis will start with PGE's historic

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88 REC's December 3, 2021 Reply Comments, page 2.
89 REC's December 3, 2021 Reply Comments, pages 3-5.
90 REC's December 3, 2021 Reply Comments, pages 10-12.
91 REC's December 3, 2021 Reply Comments, page 12.
92 PAC's December 23, 2021 Response Comments, page 47.
93 PAC's December 23, 2021 Response Comments, page 47.
94 PAC's December 23, 2021 Response Comments, page 46.

> percentage of PGE's QFs that have renewed their contracts. PGE's will also review the historic percentage of QFs reaching completion and renewals for other utilities.[95]

Staff finds merit in the PAC's argument that QF compensation decisions should be made outside of the IRP. Staff is open to PAC's highlighting of REC's suggestion as a solution: "One suggested resolution of this issue from REC's comments would be for the Commission to require PacifiCorp to simply continue paying a QF the capacity payment identified at the outset of a PPA (*i.e.*, eliminate the sufficiency period at the beginning of a new or renewed QF contract)."[96] Staff agrees with PAC that this could be accomplished in UM 2000, UM 2011, or UM 2038 instead. PAC argues that it "cannot require a QF to renew… which would make their inclusion problematic from a planning perspective."[97] Reflecting PAC and REC's concerns, Staff recommends in the short-term: allow assumption of no renewals based on PAC's problematic planning perspective, however, do not withhold capacity payments from QFs that do actually renew based on REC's suggested solution.

Recommendation 39: In the public input process prior to its 2023 IRP, PAC should engage with stakeholders in the public input process to propose a method for modeling some level of assumed QF renewals in its next IRP and then apply said modeling in its 2023 IRP.

3.1.3 Adaptation Plan Scope

In Opening Comments, Staff noted that the Company addressed the requirements in Order No. 20-186 directing the Company to include a proposal for the scope of a potential climate adaptation study in the 2021 IRP. Staff described additional elements it hoped to see in an adaptation study and noted that the Company provided suggestions about how to begin incorporating climate change adaptation considerations into an IRP. Staff invited stakeholders to provide suggestions for incremental improvements that the Company could make to address climate change adaptation.

Staff understands that climate adaptation planning includes consideration of applicable climate-related risks: physical, transition, and tail-end risks.[98] In Opening Comments, Staff pointed to climate risk guidance from the World Business Council on Sustainable Development, which suggests that climate-risk reports include a description of a company's process for identifying, assessing, and managing climate-related risks and how it integrates these risks into its overall risk management. In their respective Opening Comments, CUB and RNW provided additional suggestions on how PAC could improve on climate change adaptation analysis through additional and modified climate-related analysis in its 2023 IRP. While the above referenced order focused on elements of an adaptation plan, PAC's willingness to consider how to reflect climate risk in an IRP aligns with the suggestions provided by stakeholders and Staff. Staff supports the consideration of additional climate-related risks in PAC's future IRPs as a way

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[95] Order No. 21-215, In the Matter of PGE Updates to Schedule 201 Qualifying Facility (10 MW or less) Avoided Cost UM 1728, Appendix A, page 12.
[96] PAC's December 23, 2021 Response Comments, page 46.
[97] PAC's December 23, 2021 Response Comments, page 48.
[98] https://docs.wbcsd.org/2019/07/WBCSD_TCFD_Electric_Utilities_Preparer_Forum.pdf.

to identify, assess, and manage climate-related risks as part of a climate change adaptation strategy.

To support climate adaptation planning, Staff believes future IRPs could be improved with an expanded and enhanced identification and assessment of climate-related risks. This includes changes to how weather and extreme events are considered; consideration of how climate-related risks affect supply side resources, transmission, and loads; and an assumption of climate change impacts as part of the status quo. While Staff describes them separately, these impacts appear to not happen in isolation, but form a perfect storm of risks because of their close correlation. WECC has observed much less transmission availability during extreme events, greatly limiting imports. WECC also notes that the correlation runs across multiple elements of a model. Recent extreme weather has impacted three things simultaneously, namely: availability of transmission for imports; reduced energy production; and greatly spiked load/demand.

Weather and Extreme Events

WECC's 2021 Western Assessment of Resource Adequacy points to recent extreme weather driving greater variability in both demand (e.g., extreme heat and AC across region for days) and in energy supply (e.g., renewable energy production less predictable). These events point to the need to update models as observed extreme events in recent years indicate a strong trend for them to continue into the future.

> Weather creates variability, and weather is growing more erratic and extreme—a pattern that is expected to continue over the next decade. Based on data reported by Balancing Authorities (BA), demand and resource variability have increased and will continue to increase over the next decade. In addition, predictions about more extreme weather and changing climate patterns portend increases in variability, likely beyond what entities currently predict.[99]

In their Opening Comments, RNW recommended that IRPs should model increasing frequency of extreme conditions that could trigger shortfalls. Staff agrees with RNW and adds that it appears PAC's 1-in-20 scenario appears to be backward looking and does not contemplate extreme weather events.[100] The weather patterns of the past may not capture the extremes and variability expected (and experienced) with continued climate change. It is Staff's impression that PAC's current extreme weather event modeling might not reflect current best practices.

Both CUB and RNW suggested that PAC work with NWPCC to update its weather data set to better reflect climate impacts. Staff is supportive of this suggestion and is open to additional means by which the Company might update its weather data set such that it reflects best practices in capturing climate related weather data in planning. Staff notes a recent report by

[99] WECC Western Assessment of Resource Adequacy. Page 4.

[100] PacifiCorp's 2021 Integrated Resource Plan. Page 252.

Pacific Northwest National Labs, which includes a variety of best practices (including some already implemented by the Company) that should be considered.[101]

Climate-Related Supply Side Risks

Climate change has resulted in generation and transmission impacts that should be modeled as supply side risks. These impacts include, but likely are not limited to derating of thermal plants and transmission, transmission availability, and tightening gas supplies, in addition to reliability risks of low water years – which are more likely and more widespread than the historical record demonstrates. In its report on limited transmission for imports due to extreme weather, WECC stated: "Changes in climate, weather, load patterns, resource location, and resource availability have altered how and when entities can rely on import capacity and the capability of the transmission system to move power."[102]

CUB suggested that future IRPs should better consider hydrological cycles (temperature, timing, volume) and the subsequent impact on hydropower generation and thermal cooling availability and pointed to modeling done by the Tennessee Valley Authority. CUB recommended that PAC review best practices in climate change modeling by peer utilities. RNW recommends PAC work with NWPCC to implement datasets to reflect climate risk impacts on hydro datasets
In Reply Comments, PAC agreed that resource impacts are an important component of climate change modeling and said it would continue to evaluate best practices to model these climate risks in future IRPs. Staff appreciates the Company's continued effort to seek out and implement best practices in climate-related supply side risks modeling and recommends the Company work with Stakeholders to identify and implement updated datasets and modeling methodologies that consider correlation of impacts in its TWG meetings as part of its next IRP process.

Climate-Related Load changes

Both weather related climate impacts and policies designed to reduce GHG emissions have the potential to result in behavior and market changes affecting load. Stakeholders identified a number of these climate-related risks that could affect load, and which they recommend be taken into consideration in the next IRP. These include the increased use of air conditioning (residential and at data centers) and the timing of that usage; increased adoption of electric vehicles; policies considering increased building electrification; and the potential for increased population due to climate migration to Oregon.

Staff believes the next IRP should attempt to capture these risks in the load forecasts. Regarding increased population due to climate migration, CUB points to estimates from the Northwest Power Plan, however, Staff is open to other approaches that can be adequately supported. Staff recommends that the Company assemble approaches for identifying and assessing climate-related load changes related to air conditioning, transportation

[101] See A Review of Water and Climate Change Analysis in Electric Utility Integrated Resource Planning October 2021 https://epe.pnnl.gov/pdfs/Water_in_IRP_whitepaper_PNNL-30910.pdf
[102] WECC Western Assessment of Resource Adequacy. Page 4.

electrification, and climate migration and present them as part of its technical working groups in advance of the next IRP. RNW recommends PAC work with NWPCC to implement datasets that reflect climate risk impacts on load. Staff generally agrees with RNW and recommends that the Company work with Stakeholders to identify and implement updated datasets reflecting best practices in the PLEXOS modeling environment in its next IRP process.

Regarding increased building electrification, CUB recommends the Company use electrification scenarios proposed as part of OPUC Docket No. UM 2178. PAC replied that it does not currently model building electrification in Oregon because there is no current legislation related to building electrification. Staff is very interested in establishing consistent guidance regarding potential building electrification modeling and appreciates CUB referencing current efforts in this respect. However, until the final UM 2178 report is approved by the Commission, Staff believes it is premature to recommend a 2178 scenario for the 2023 IRP. The UM 2178 Draft report will be released in the first quarter of 2022 and Staff anticipates it being approved by the second quarter of 2022. Staff recommends that PAC await the recommendations associated with that docket before initiating building electrification assumptions, but welcomes PAC's feedback and engagement on this topic. Regardless, Staff requests the Company work closely with PUC Staff and Stakeholders to identify appropriate levels of building electrification for modeling in its next IRP.

Climate change as Status Quo

Staff appreciates that the Company has incorporated climate change into its modeling and looks forward to updating the modeling based on best practices. Staff further appreciates the Company's awareness of the impacts climate change is currently having on reliability and the variability and uncertainty this introduces into planning. However, in addition to updating weather, load, and supply forecasting to reflect best practices as informed by climate science, Staff believes that PAC should strive to reflect climate change as the status quo.

In their Opening Comments, RNW stated that climate change impacts should be included in baseline portfolio modeling, and not just as a sensitivity. PAC, in Reply Comments suggested it is better to consider impacts as a sensitivity in this early stage of development. Staff also supports the inclusion of climate change impacts in baseline portfolio modeling and not just in IRP sensitivity analyses.

Recommendation 40: Before the 2023 IRP, include climate-change risk and adaptation as a topic of a public-input meeting to share and discuss approaches to modeling climate risk in the IRP including: proposed changes to how weather and extreme events are considered; proposed changes for the consideration of climate-related risks on supply side resources, transmission, and loads; and a discussion on how the Company proposes to include climate change impacts as part of the status quo.

3.1.4 PacifiCorp's Ongoing Regulatory Requirements

In the 2019 IRP, the Commission directed PacifiCorp and Staff to look into PacifiCorp's Oregon compliance items that carry forward into each IRP, and determine which items are no longer relevant or necessary.[103]

Staff and PacifiCorp identified one filing that is currently required from the Company twice each year that could likely be filed less frequently with similar effectiveness. The "Biannual Environmental, Transmission, and DSM Update" is required by Order No. 16-071, and is filed in PacifiCorp's IRP dockets twice a year. This filing could likely be made once annually with similar benefits to stakeholders. Alternately, it could be filed about one year after the filing of an IRP to provide updated data between the filing of the IRP and the filing of the IRP update.

Recommendation 41: The Commission should direct PacifiCorp to file its Biannual Environmental, Transmission, and DSM Update once annually instead of biannually. Alternately, Staff would support a filing of this report one year after the filing of each IRP.

3.2 Compliance with Oregon IRP Guidelines

Draft IRP

In Opening Comments, Staff expressed concern over the fact that PAC did not submit a draft IRP prior to filing its final IRP.[104] NWEC also raised concerns regarding the lack of submission of a draft IRP.[105] Staff asked PAC to commit to providing a draft IRP in the next IRP cycle for review and comment at least four weeks before filing.[106]

PAC rejected Staff's request.[107] PAC asserted that its existing process for meeting the draft IRP requirement is a "qualitatively superior and less disruptive process compared to the establishment of a draft document submission."[108] PAC went on to explain that the public-input meetings, meeting materials reviewed with stakeholders, and consideration of extensive stakeholder feedback forms received throughout the development cycle is collectively representative of a draft IRP.[109] Further, PAC explained that this is how it has approached a draft IRP in past IRP processes as well.[110]

PAC also took issue with the four-week timeframe offered by Staff, noting that it effectively doubles the time required for internal drafting, validation, formatting and review at all levels.[111]

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[103] Order No. 20-186. Page 24-25.
[104] Staff's Opening Comments. Pages 33, 46.
[105] NWEC Opening Comments. Page 1.
[106] Staff's Opening Comments. Pages 33, 46.
[107] PAC's Reply Comments. Pages 12-13.
[108] PAC's Reply Comments. Pages 12-13.
[109] PAC's Reply Comments. Page 12.
[110] PAC's Reply Comments. Page 12.
[111] PAC's Reply Comments. Page 13.

Further, PAC argued that four weeks is not sufficient time for all parties to review and comment meaningfully on a new and comprehensive document and for PAC to assess and integrate additional recommendations for the final filing.[112]

Staff continues to recommend that PGE provide an actual draft IRP in its next IRP cycle. Staff disagrees with PAC's assertion that the public-input meetings, meeting materials, and consideration of stakeholder feedback forms throughout the IRP development process is collectively representative of a draft IRP. Those are all important in meeting the IRP Guidelines generally, but do not suffice for the draft IRP requirement as it does not provide visibility to how the Company has responded to the feedback from stakeholders and does not provide a means for stakeholders to understand how the various IRP elements come together to form a plan.

Further, regarding the four-week timeline that PAC objected to, Staff suggested that timeline as a minimum.[113] As a result, PAC's argument that four weeks is not enough time could easily be addressed by PAC suggesting a longer timeline. Instead, it just said it could not be done.

Staff would also note that other companies have provided draft IRPs and incorporated feedback on those as part of their IRP development process in relatively short order. For PGE's 2019 IRP (LC 73), PGE filed a draft IRP dated May 17, 2019; Staff and stakeholders provided feedback in June; and PGE incorporated that feedback and filed its final IRP on July 19, 2019.[114] For its 2023 IRP, PGE again plans to share a draft IRP. PGE is planning to share the draft IRP and action plan and file the final IRP over the three month span of January-March 2023.[115]

PAC certainly has the option to pursue a waiver of the requirement and try to demonstrate good cause for it if the Company does not want to provide an actual draft IRP in its next IRP cycle.[116] Absent a successful waiver, Staff would expect PAC to submit an actual draft IRP. Given the role and timing of the draft IRP in the IRP process, Staff would expect PAC either receive a successful waiver from the Commission or provide the draft RFP at least four weeks prior to the filing of the final IRP.

Staff also notes that there could be additional relevant discussion and guidance on changes to the IRP process as part of the recently launched Clean Energy Plan Investigation Docket (UM 2225).

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[112] PAC's Reply Comments. Page 13.

[113] See Staff's Opening Comments. Pages 33, 46. "Staff requests PacifiCorp respond in reply comments whether it will commit to provide a full draft IRP for review and comment at least four weeks in advance of its IRP filing in the next IRP cycle." "Staff is recommending at least four weeks for review of a draft IRP before filing of a final IRP."

[114] LC 73, PGE's Integrated Resource Plan filed July 19, 2019. See page 1 of the cover letter. https://edocs.puc.state.or.us/efdocs/HAA/lc73haa162516.pdf

[115] PGE's Integrated Resource Planning Roundtable 22-1 Presentation. January 2022. Slide 9. https://assets.ctfassets.net/416ywc1laqmd/7cxcVacdmTWeIFsfP7G9cG/2a99ba1e764c753b02b899645d5b692e/IRP_Roundtable_January_22-1.pdf

[116] See OAR 860-027-0400(1).

Consistent & Comparable Resource Evaluation
In certain instances, Staff finds that PacifiCorp did not evaluate all known resources on a consistent and comparable basis. Most notably:

- The optimistic set of assumptions for the cost, timing, and risks of Natrium relative to the variables for competing non-emitting but not-widely-deployed resources such as green-hydrogen gas turbines, utility-scale geothermal, offshore wind, and pumped hydro.
- Not including known resources from cluster studies as potential resources in the IRP modeling. Most notably for staff is the cluster of approximately 300 MW of solar + storage projects in Crook County. The cost of the network and transmission upgrades ($47 M) for this cluster are competitive with any generation associated with EGS upgrades and while PURPA projects, due to their size, the price and terms are negotiable.
- Using outdated assumptions for Swan Lake pumped hydro while beginning to pursue the development of an alternative pumped hydro elsewhere in Southern Oregon.

Staff would note that one common thread running through these three examples of not comparing on a consistent and comparable basis, namely utility ownership. PacifiCorp said in their reply comments they plan to own Natrium. The large amount of solar and storage projects in Crook County and the 400 MW Swan Lake project are not owned by the Company. While the recently completed PAC RFP (UM 2059) included a large number of wind and solar PPAs, they all supported the building of a large amount of new transmission, owned by PacifiCorp.

The individual remedies suggested by Staff in this IRP for each example above should mitigate concerns about Staff's perception of bias toward utility ownership in the modeling choices by the Company. In the 2023 IRP Staff plans to work with the Company and stakeholders to add a new criteria to portfolio evaluation to supplement NPVRR and risk metrics: estimated addition to rate base.

3.2.1 Public process

2023 IRP/CEP/RFP Timing
PAC's Reply Comments raise some timing-related issues regarding the next IRP. PAC explained that it plans to submit its next IRP in March 2023.[117] It also noted that it would expect to file the required Clean Energy Plan by September 2023.[118] Finally, PAC explains that if the 2023 IRP identified a resource need, the Company would expect to file a draft RFP for approval within 120 days of the filing of the 2023 IRP.[119]

[117] PAC's Reply Comments. Page 85.
[118] PAC's Reply Comments. Page 85.
[119] PAC's Reply Comments. Pages 85-86.

Staff would find it hard to recommend acknowledgement of PAC's next IRP without also reviewing PAC's Clean Energy Plan. The Clean Energy Plan is foundational to understanding PAC's resource planning moving forward. To this point, Staff recently recommended PGE file its Clean Energy Plan with its next IRP, which the Commission supported.[120]

Staff also reminds PacifiCorp that Staff has expressed concerns in the past about PAC pursuing an RFP prior to receiving acknowledgment of and concurrent to an open IRP.[121] These concerns are magnified with the overlay of compliance with HB 2021 and the required Clean Energy Plan as part of the planning process.

Finally, Staff notes that there could be additional relevant discussion and guidance on these items as part of the recently launched Clean Energy Plan Investigation Docket (UM 2225).

Summary of Recommendations

Recommendation 1: In the 2023 IRP, PacifiCorp should provide a metric calculated in its capacity expansion model that provides stakeholders with an estimate of the relative value of each coal unit to the system.

Recommendation 2: If the data on the relative value of each coal unit is available for 2021 IRP resources, the Company should provide the data in a filing before the acknowledgement decision meeting. If the data is considered confidential, then a ranked table of PacifiCorp's coal units from least to most valuable should be provided in the filing in a non-confidential format.

Recommendation 3: The 2023 IRP data discs should provide graphs of the average fixed and variable costs of operating each coal unit over the planning timeframe. This should include fuel cost and run rate capital, but exclude depreciation expense.

Recommendation 4: Perform an investigation of the potential to burn green hydrogen at the converted Bridger units and report on its findings in the 2023 IRP, including an explanation of the engineering reasons that a converted boiler would or would not be able to accommodate a percentage of green hydrogen.

Recommendation 5: If technically feasible, PacifiCorp should report on the costs and emissions (CO2 and NOX) of green hydrogen combustion at the converted Bridger unit.

Recommendation 6: The 2023 IRP should more thoroughly investigate the potential to install a new turbine designed to run on 100 percent green hydrogen at the sites of one or more retiring coal plants.

Recommendation 7: PacifiCorp should file the results of its coal sensitivity at least seven (7) days before the February 24, 2022 Commissioner Workshop in LC 77, and be prepared for a discussion of Take or Pay modeling at Jim Bridger 3 and 4.

[120] See LC 73, Order No. 21-422.

[121] See Staff's Memo dated October 11, 2021 in Docket No. UM 2193. Pages 9-12.

Recommendation 8: The 2023 IRP should consider endogenous retirement of Jim Bridger 3 and 4 at least once every two years.

Recommendation 9: In the 2023 IRP, PacifiCorp should carefully review the capital and O&M cost forecasts for Jim Bridger 3 and 4 and provide workpapers comparing historical costs at these units to the IRP cost forecast, including the categories of Variable O&M, Fixed O&M, and run-rate capital.

Recommendation 10: In the 2023 IRP, variable O&M costs should be modeled accurately as variable with generation, and not approximated as part of fixed O&M costs as they have been in the 2021 IRP.

Recommendation 11: PacifiCorp should perform a sensitivity before the acknowledgement decision meeting in this IRP on March 22, 2022, where the Huntington minimum take agreement ends in 2023.

Recommendation 12: Staff recommends acknowledging the preferred portfolio and Action Plan only to the extent that they are consistent with the no-Natrium scenario.

Recommendation 13: Staff recommends a Commission workshop at least one month in advance of the 2022 AS RFP Final Shortlist for stakeholders, PacifiCorp, and Commissioners to discuss potential benefits of acquiring additional near-term supply or demand side capacity, including in the 2022 RFP, to help reduce future resource allocation risk for Oregon.

Recommendation 14: Regarding the Natrium plant, PacifiCorp should not pursue an alternative acquisition method but may include the plant as a part of a competitive RFP where it can compete against other resources providing similar types of services.

Recommendation 15: In Reply Comments, PacifiCorp should provide responses to Staff's thoughts on incorporating flexible hydrogen load onto PacifiCorp's system.

Recommendation 16: Before the PacifiCorp IRP meeting to discuss supply side resources in early 2022, Staff will convene a brief Oregon stakeholder conference to discuss ways to model hydrogen resources in the 2023 IRP and potential tariffs to encourage hydrogen load generation timed and located in ways that benefit the system.

Recommendation 17: PacifiCorp should conduct a stakeholder feedback process to determine what source the Offshore Wind cost data in the 2023 IRP will be based on, with consideration for public data such as the 2021 U.S. DOE Offshore Wind Market Report.

Recommendation 18: PacifiCorp should conduct an analysis akin to the sensitivity Staff proposed in Opening Comments that considers the development of Offshore Wind in comparison to resources associated with the 2022 AS RFP Final Shortlist and publish the analysis with the 2022 AS RFP Final Short List.

Recommendation 19: After a conversation with Staff and stakeholders, PacifiCorp should engage with PacifiCorp Transmission prior to the 2023 IRP to request a power flow study of the addition of Offshore Wind near Brookings, Oregon to inform what upgrades or enhancements might be needed to interconnect 500 MW to 1,000 MW at this location.

Recommendation 20: Regarding these Oregon QF projects, re-run the IRP model using the solar or solar + storage proxy costs and CF values for these QFs, including identified interconnection costs, to see how these QF resources compete in the model, if they are selected, and their impact this IRP's other resource selections.

Recommendation 21: Much like offshore wind, Staff requests that an analysis considering the development of these projects in comparison to resources associated with the Final Shortlist be published with the Final Shortlist in the 2022 AS RFP.

Recommendation 22: Depending on the outcome of UM 2032 and based on the benefits of the seven Oregon QF cluster study projects, provide a report on the impact of ratepayers covering some or all of the Network Upgrade costs and negotiating terms with these projects so they can be brought online before 2026 to serve customer demand identified in the IRP.

Recommendation 23: For the 2023 IRP, PacifiCorp should take steps necessary to provide complete and accurate information in the IRP document that reflects actual IRP modeling assumptions.

Recommendation 24: In the 2023 IRP, PacifiCorp's storage costs should be in line with the most recent NREL ATB report and most recent RFP Final Shortlist before publishing the Supply Side Table.

Recommendation 25: The 2023 IRP executive summary should include a map of resources added in the preferred portfolio by year and location.

Recommendation 26: In future IRPs or during future RFP processes, potential RFP bidders should be given access to a 12x24 Loss of Load Probability matrix for one out of every five years in the IRP planning timeframe.

Recommendation 27: In the 2023 IRP, PacifiCorp should clearly explain the reliability limitations of the LT capacity expansion model, and how the IRP team selected the reliability resources to add to the ST model.

Recommendation 28: The 2023 IRP workpapers should include a report of the timing and duration of reliability events from the ST run that necessitated the addition of reliability resources in each portfolio.

Recommendation 29: PacifiCorp should re-run its IRP model using updated cost assumptions for pumped hydro storage, either as a part of a requested sensitivity to the 2021 IRP, or in the 2023 IRP.

Recommendation 30: PacifiCorp should discuss and compare the transmission and operational constraints faced by Swan Lake relative to the proposed Crooked Creek in its final IRP comments.

Recommendation 31: As part of the 2023 IRP public workshop series, the Company should review the pumped hydro project proposals PacifiCorp is considering and detail the potential benefits of pumped hydro in an era of decarbonization, including the reliability benefits of adding more than one project to its portfolio and the benefits of adding

mass/inertia from large rotating generators to an increasingly inverter-based portfolio of resources.

Recommendation 32: In the 2023 IRP, PacifiCorp should describe how it delineates between reliability-related transmission system improvements and those which are deemed resource-related. Further, transmission system improvements should be clearly specified as reliability or resource related .

Recommendation 33: In Reply Comments, PacifiCorp should provide additional clarity on the data submitted to WRAP Program Operator in the 2021 IRP.

Recommendation 34: In the 2023 IRP, PacifiCorp should be required to clearly show how its IRP Planning Reserve Margin is consistent with any PRM assigned to the Company in the WRAP process. Any deviation from the WRAP PRM should be thoroughly explained and justified.

Recommendation 35: Staff recommends a Commission workshop to discuss potential ways to increase efficiency and demand response to decrease resource allocation risk for Oregon customers, including but not limited to consideration of a new or updated risk-reduction credit to efficiency.

Recommendation 36: Before the next IRP, PacifiCorp should hire a consulting firm to help PacifiCorp staff design a Peak-Time Rebate program for Oregon. In their work, the consultant should benchmark best practices from the most impactful programs by other utilities and suggest Class 3 DSM designs capable of working with PacifiCorp's existing AMI, billing, and customer communication systems. The Company should present the consultant's findings to an IRP stakeholder workshop prior to filing the next IRP.

Recommendation 37: Acknowledge all action items except the element of item 2c to "finalize commercial agreements" for Natrium, items 3a and 3b because they have been discussed at length in previous dockets, and 3d because it is vague and insufficient supporting data has been provided.

Recommendation 38: PacifiCorp address ownership diversity and risks in its derivation of future RFP shortlists.

Recommendation 39: In the public input process prior to its 2023 IRP, PAC should engage with stakeholders in the public input process to propose a method for modeling some level of assumed QF renewals in its next IRP and then apply said modeling in its 2023 IRP.

Recommendation 40: Before the 2023 IRP, include climate-change risk and adaptation as a topic of a public-input meeting to share and discuss approaches to modeling climate risk in the IRP including: proposed changes to how weather and extreme events are considered; proposed changes for the consideration of climate-related risks on supply side resources, transmission, and loads; and a discussion on how the Company proposes to include climate change impacts as part of the status quo.

Recommendation 41: The Commission should direct PacifiCorp to file its Biannual Environmental, Transmission, and DSM Update once annually instead of biannually. Alternately, Staff would support a filing of this report one year after the filing of each IRP.

This concludes Staff's Report.

Dated at Salem, Oregon, this 11th of February, 2022.

/s/ Rose Anderson
____
Rose Anderson
Senior Economist
Energy Resources and Planning Division

CERTIFICATE OF SERVICE

LC 77

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 11th day of February, 2022 at Salem, Oregon

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