PACIFIC POWER
A DIVISION OF PACIFICORP

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February 5, 2020

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-3398

Attn: Filing Center

RE: LC 70—PacifiCorp's Reply Comments

PacifiCorp d/b/a Pacific Power encloses for filing its Reply Comments in the above-referenced docket.

Informal inquiries may be directed to Cathie Allen, Regulatory Affairs Manager, at (503) 813-5934.

Sincerely,

Etta Lockey
Vice President, Regulation

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 70

In the Matter of PACIFICORP d/b/a PACIFIC POWER 2019 Integrated Resource Plan	PACIFICORP'S REPLY COMMENTS

I. INTRODUCTION AND SUMMARY

PacifiCorp d/b/a Pacific Power filed its 2019 Integrated Resource Plan (IRP) with the Public Utility Commission of Oregon (Commission) on October 18, 2019. On January 10, 2020, the following stakeholders submitted written comments in response to PacifiCorp's 2019 IRP: Commission Staff (Staff), Renewable Northwest (RNW), the Alliance of Western Energy Consumers (AWEC), the Renewable Energy Coalition (the Coalition), the Citizens' Utility Board of Oregon (CUB), the Northwest Energy Coalition (NWEC),[1] the Northwest and Intermountain Power Producers (NIPPC), Sierra Club, and Swan Lake North Hydro, LLC (Swan Lake).

PacifiCorp looks forward to continuing to work with stakeholders in their review of the 2019 IRP. The company is also appreciative of the feedback received through the IRP development process and opening stakeholder comments[2] that recognize improvements made to the IRP stakeholder feedback form process and public-input process.[3] PacifiCorp notes that

[1] NWEC filed corrected comments on January 13, 2020. All references to NWEC's Opening Comments are references to these corrected comments.
[2] Pursuant to the procedural schedule in this proceeding, comments due on January 10, 2020 were "opening comments." Staff and Renewable Northwest entitled their comments "initial" comments. General references to "opening comments" in these reply comments are intended to include the "initial" comments of Staff and RNW while specific citations refer to document titles as filed.
[3] *See*, *e.g.*, NWEC Opening Comments at 1 and CUB Opening Comments at 1. The company notes that requests for continued improvement are also made through these opening stakeholder comments and it will do its best to make these improvements as the 2021 IRP process begins.

Staff's initial comments identify areas of the IRP where their review continues; the company is not providing specific responses to all of these identified areas at this time. The company is willing to work with stakeholders, including Staff, to consider an additional workshop (or workshops, if necessary and practicable) to address specific areas of interest. For example, in its initial comments, Staff requests a workshop that would allow the company to share the details of its queue reform proposal with Staff and stakeholders.[4] The Commission has also scheduled a special public meeting February 25, 2020 to hear from PacifiCorp on its transmission interconnection queue reform proposal that was submitted to the Federal Energy Regulatory Commission (FERC) January 31, 2020. The company also notes that the Commission has already scheduled workshops where additional discussion and information exchange could occur; the first Commission workshop is scheduled for February 13, 2020, where the company anticipates it will provide an update on its action items. PacifiCorp has also made note of suggestions in the opening stakeholder comments that are directed towards the next IRP cycle[5] which PacifiCorp will consider and which the company encourages stakeholders to also raise as part of the 2021 IRP public input process.[6]

In these reply comments, PacifiCorp:

- Summarizes the Commission's standards for IRP acknowledgment, and explains how the 2019 IRP and the associated action plan meets these standards.
- Provides clarification regarding the development of its coal analysis assumptions.

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[4] Staff's Initial Comments at 60. As detailed below, other stakeholders also asked questions regarding the impact of queue reform and the upcoming request for proposals.
[5] *See, e.g.*, Staff Initial Comments at 6-7 (requesting that the company perform sensitivities on two or three top-performing portfolios to compare performance of those portfolios as part its next IRP analysis); *see also* Staff Initial Comments at 32 (requesting that the company include a study of potential battery storage remediation, recycling and disposal methods and costs with the next IRP if battery storage remains a prominent resource).
[6] The 2021 IRP stakeholder input process has already commenced and the schedule for upcoming meetings can be found on the company's website: https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html.

- Confirms that the 2019 IRP already contains all cost-effective demand-side management (DSM) resources while committing to additional stakeholder engagement to maximize these resources in the next IRP cycle.
- Provides additional support regarding the identified resource and transmission need set forth in the 2019 IRP and how that need will be met through PacifiCorp's action plan and specifically, through the upcoming request for proposals.
- Provides clarification for how the company will comply with the Commission's competitive bidding rules adopted in docket AR 600 when seeking to acquire resources identified in the 2019 IRP action plan.
- Responds to questions regarding the transmission action items identified in the 2019 IRP and how these transmission action items will facilitate the interconnection of new renewable resources to PacifiCorp's system.
- Responds to concerns regarding its IRP assumptions related to renewal of qualifying facility (QF) contracts.

II. OVERVIEW OF THE 2019 IRP

A. The 2019 IRP Satisfies the Commission's Standards for Acknowledgement

The Commission will acknowledge a utility's IRP if the plan meets the substantive and procedural requirements for least-cost planning and is "reasonable at the time that acknowledgement is given."[7] In an IRP, the Commission "looks at the reasonableness of individual actions in the context of the entire plan."[8] "The Commission generally does not address the need for specific resources, but rather determines whether the utility has proposed a

[7] *In the Matter of Public Utility Commission of Oregon Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 at 2 (Jan. 8, 2007) (corrected by Order No. 07-047).
[8] *Id.* at 25.

portfolio of resources to meet its energy demand that presents the best combination of cost and risk."[9]

The Commission's IRP guidelines require that the IRP:

- Evaluate all resources on a consistent and comparable basis;
- Consider risk and uncertainty;
- Selects a portfolio of resources with the best combination of expected costs and associated risks and uncertainty for the utility and its customers; and
- Be consistent with the long-run public interest as expressed in Oregon and federal energy policies.[10]

PacifiCorp's 2019 IRP and action plan complies with the Commission's requirements for resource planning and ensures that PacifiCorp will provide adequate and reliable electricity supply at a reasonable cost "consistent with the long-run public interest."[11] The 2019 IRP preferred portfolio includes accelerated coal retirements and investment in transmission infrastructure that will facilitate the addition of 6,400 MWs of new renewable resources by the end of 2023, with nearly 11,800 MWs of new renewable resources over the 20-year planning period through 2038.[12] To facilitate the delivery of new renewable resources, the preferred portfolio also includes a 400-mile transmission line known as Gateway South that will connect southeastern Wyoming and northern Utah. These renewable resources will expand and further diversify the company's portfolio while also meeting changing customer needs. The economic drivers behind this plan leads to a portfolio that is consistent with Oregon law establishing

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[9] *In the Matter of Idaho Power Company 2009 Integrated Resource Plan,* Docket No. LC 50, Order No. 10-392 at 2 (Oct. 11, 2010).
[10] Order No. 07-002 Appendix A at 1-2 (corrected by Order No. 07-047).
[11] *Id.* at 7.
[12] Resources acquired through customer partnerships, used for renewable portfolio standard compliance, or for third-party sales of renewable attributes are included in the total capacity figures quoted.

renewable energy targets and that requires coal-fueled resources be eliminated from electricity rates; PacifiCorp's preferred portfolio sets a course to meet these requirements while ensuring that customers are served reliably and at least-cost.

PacifiCorp's selection of the 2019 IRP preferred portfolio is supported by detailed data analysis using five fundamental steps: (1) a comprehensive and robust analysis of the company's coal units; (2) development of a wide-range of resource portfolios; (3) targeted reliability analysis of the portfolios to ensure sufficient flexible capacity resources to meet reliability requirements; (4) analysis of the resource portfolios to measure comparative costs, risks, reliability and emission levels that inform selection of a preferred portfolio; and (5) development of the near-term resource action plan required to deliver resources in the preferred portfolio.[13] Each of these steps in the 2019 IRP development process are presented in greater detail in the company's filing, including the supporting work papers that present the underlying data for each of the portfolios analyzed by PacifiCorp.

The 2019 IRP development process also benefited from modeling advancements including a robust analysis of its coal units, the ability of the System Optimizer (SO) model to endogenously view the costs and benefits associated with specific transmission upgrades and to optimize transmission upgrade selections within the model based on targeted portfolio reliability analysis using the Planning and Risk model (PaR); and improved storage modeling through use of a tool that better optimizes charge and discharge cycles.[14] Through this extensive process, the company was able to develop a preferred portfolio that meets its long-term goals of providing sustainable and affordable service to its customers.

[13] 2019 IRP Volume I at 6.
[14] 2019 IRP Volume I at 19.

Although the 2019 IRP uses a 20-year planning horizon, the Commission has historically focused on the action plan, which identifies the specific resource actions PacifiCorp intends to undertake in the next two to four years.[15] The key resource actions in the 2019 IRP action plan include the following items:

- **Action Items 1b, 1c and 1d**: PacifiCorp will initiate the retirements of Cholla Unit 4, Jim Bridger Unit 1, and Naughton Units 1-2. These units are currently expected to be retired by year end 2020, 2023 and 2025, respectively.
- **Action Item 2a**: PacifiCorp will issue an all-source request for proposals to procure resources that can achieve commercial operations by the end of December 2023.
- **Action Items 3a, 3f and 3g**: PacifiCorp will seek to develop new transmission capacity through the Energy Gateway South, Boardman-to-Hemmingway (B2H), and Energy Gateway West projects. These projects will allow the company to facilitate the interconnection of new resources.
- **Action Item 4a:** PacifiCorp will acquire cost-effective energy efficiency resources with state specific targets. Acquiring additional energy efficiency throughout the company's service territory will provide benefits to all customers.

The combination of these key action items will allow the company to move into the future with a reliable, diverse portfolio that minimizes risk and costs to PacifiCorp's retail customers.

III. REPLY TO PARTIES' OPENING COMMENTS

A. The Company's Coal Study Assumptions are Reasonable

PacifiCorp is appreciative of the opening comments that acknowledge the company's analysis of its coal units and is carefully reviewing the stakeholder feedback that will facilitate additional improvements in the 2021 IRP cycle.[16] The company also notes that with respect to developments in the timelines associated with coal retirements, PacifiCorp will continue to

[15] *Id.* at 12.
[16] *See, e.g.,* RNW Opening Comments at 12, Sierra Club Opening Comments at 1, and NWEC Opening Comments at 2-3.

update stakeholders as these developments occur. Staff's initial comments recommend that the company provide the best estimate for when its Cholla unit will retire and use this updated estimate in any upcoming request for proposal (RFP) analysis.[17] PacifiCorp has continued to actively pursue the retirements dates identified in the 2019 IRP preferred portfolio and associated action plan. On January 5, 2020, PacifiCorp notified IRP participants that PacifiCorp plans to retire Cholla Unit 4 by the end of 2020. This closure date will be reflected in the company's RFP analysis. The company will also continue to re-evaluate the economics of its coal units in future IRPs.[18]

i. <u>The company has accurately and appropriately accounted for environmental compliance costs associated with its coal units.</u>

In its opening comments, CUB asserts that selective catalytic reduction (SCR) installations for coal units Jim Bridger 1 and 2 should not have been included in the coal study benchmark assumptions because these investments (*i.e.*, the investments in these SCR installations) were not found to be cost-effective in the company's 2017 IRP and therefore it is unlikely that they will be found cost-effective as part of the 2019 IRP.[19] CUB does, however, acknowledge that even if it were inappropriate to include these investments, it is unlikely that the inclusion of the SCR investments in the assumptions influenced the outcome of the 2019 IRP.[20]

PacifiCorp agrees with CUB that even if the SCR installations for Jim Bridger Units 1 and 2 had not been included in the benchmark assumptions, the outcome of the analysis regarding coal units would not have changed. The company, however, disagrees with CUB's claim that it was inappropriate to include the SCR investments for Jim Bridger Units 1 and 2.

[17] Staff Initial Comments at 63.
[18] *See* Sierra Club Opening Comments at 23.
[19] CUB Opening Comments at 2.
[20] CUB Opening Comments at 2,

Including these investments is consistent with how the company treats its environmental compliance obligations in IRP modeling. The SCR investments are legally required by the State of Wyoming's Regional Haze State Implementation Plan (RH SIP) as approved by the United States Environmental Protection Agency (EPA).[21] The coal study benchmark case, which includes the SCR investments in its assumptions, assumes continued operation of Jim Bridger Units 1 and 2 through their end of depreciable life in 2037. These assumptions are consistent with the company's current legal requirements.

It is worth noting, however, that PacifiCorp filed an application in 2019 for a Regional Haze Reassessment of the Wyoming RH SIP with the Wyoming Department of Environmental Quality (Wyoming DEQ). This reassessment application proposes plant-wide emission limits in lieu of the SCR investment requirement for Jim Bridger units 1 and 2. Wyoming DEQ is reviewing the reassessment application; it is anticipated that Wyoming DEQ will submit the proposed changes to EPA for review. Pending a determination on the reassessment application, the coal study benchmark case included the SCR investments for Jim Bridger Units 1 and 2. The 2019 IRP preferred portfolio, however, assumes that the reassessment application will be approved[22] and, with this assumption, the preferred portfolio results in shorter operating lives for Jim Bridger Units 1 and 2 (early retirements in 2023 and 2028, respectively) driven by economics. Thus, the company agrees that even if the assumptions regarding SCR investments were not included in the coal assumptions for the 2019 IRP, the outcome for the preferred portfolio would not have been any different. Until the reassessment is approved, however, it is

[21] The Wyoming RH SIP can be viewed in EPA Docket EPA-R08-OAR-2018-0606.

[22] This assumption is reasonable because, as CUB is aware, utilities have been successful in negotiating alternative regional haze compliance outcomes in recent years with various states and the EPA including agreeing to retire a coal unit early in lieu of SCR investments. Examples of these early retirement commitments include Boardman, Cholla 4, Craig 1, and Dave Johnston 3.

not appropriate to update the baseline coal assumption that SCRs would be required on Jim Bridger Units 1 and 2 if they were to continue operating through 2037. PacifiCorp agrees to revisit the baseline coal assumptions if and when its regional haze requirements are formally amended.

For similar reasons, the company did not include any costs associated with SCRs for its Hunter and Huntington units. Sierra Club argues that failure to include such costs is a failure to accurately capture reasonably foreseeable environmental compliance costs.[23] To address this concern, Sierra Club suggests that PacifiCorp should quantitatively capture and evaluate these potential costs. The company does not agree that the costs associated with SCRs for Hunter and Huntington were reasonably foreseeable at the time the coal study was developed or even at the time of filing these comments. During the period when the coal study was performed, EPA's Regional Haze Federal Implementation Plan (RH FIP) for Utah (where Hunter and Huntington are located) that required SCRs for Hunter Units 1 and 2, and Huntington Units 1 and 2 had been stayed by the United States Tenth Circuit Court of Appeals pending EPA's reconsideration. Compliance with the Utah State RH FIP for these units therefore continues to be stayed by the Court. Utah has submitted a revised RH SIP for EPA's consideration; the revised Utah RH SIP does not require installation of SCRs on Hunter Units 1 and 2 or Huntington Units 1 and 2.[24] At this time there are no foreseeable requirements that SCRs will be required for these units and it was appropriate not to include any such costs in the company's IRP analysis.

PacifiCorp's modeling of SCR costs was consistent throughout the IRP analysis and based on current legal requirements. The only legally required SCRs at the time of the coal study

[23] Sierra Club Opening Comments 4, 20.
[24] The Utah RH SIP is available at: https://deq.utah.gov/air-quality/draft-regional-haze-2019-sip-revision.

and 2019 IRP modeling were for Jim Bridger Units 1 and 2 (discussed above) and they were appropriately included in the benchmark case.

ii. PacifiCorp's reliability resource methodology was necessary and produced accurate results.

PacifiCorp does not agree with Sierra Club's assertion that its reliability resource methodology is unsupported or likely to result in unnecessary costs.[25] Sierra Club's characterization of the 500 MW uncertainty requirement as "arbitrary" also disregards the analysis provided in the 2019 IRP and developed over the course of the public-input process with ongoing stakeholder participation. PacifiCorp introduced the importance and need for additional reliability considerations in the first 2019 IRP public-input meeting on June 28, 2018, and continued to pursue these considerations throughout the public-input process.[26] One result of these considerations was the establishment of the analytically determined 500 MW uncertainty requirement. The analysis demonstrates that the uncertainty requirement is data-driven, conservative, and demonstrably necessary. Reliable system operation is a prerequisite for any portfolio considered as a candidate for the preferred portfolio. In light of developing trends in resource types, capabilities and costs, the company reasonably determined that without this robust reliability assessment, portfolios would not achieve an adequate level of reliability to meet its load and reserve obligations. The deterministic model runs used to establish the portfolio-specific reliability requirements were performed using detailed hourly measurements on a regional and seasonal basis, accounting for all resources and system requirements. The results quantified the reliability shortfalls and demonstrated the necessity of both the uncertainty requirement and the reliability resource methodology.

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[25] Sierra Club Opening Comments at 8.
[26] *See, e.g.*, Slide 9 of the June 28, 2018 public-input meeting presentation, available at: https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html.

Further, regarding the 500 MW uncertainty requirement, Sierra Club claims that it "double-counts" reliability needs because "portfolios that PacifiCorp developed already account for these sorts of "unknowns" through the [c]ompany's application of a target planning reserve margin (PRM), hourly operating reserves requirements, and conservative market reliance limits."[27] Sierra Club's claim is incorrect; the SO model optimizes resource selection to meet load requirements and the PRM. The SO model, however, does not account for the ability of those resources to meet contingency and regulating reserves as mandated by regulatory requirements on an hourly dispatch basis, which is captured when resource portfolios are modeled in PaR. This discrepancy is exacerbated by the shift in cost-effective renewable resource selections coming out of the SO model, which lack the level of flexible dispatch relative to other resource alternatives (*i.e.*, thermal units) that can deliver differing types of operating reserves (*i.e.*, contingency, spinning, non-spinning, and regulating) in sufficient quantities across all hours to produce a reliable portfolio. PaR is capable of assessing detailed operating reserves while accounting for the increased complexity imposed by a larger amount of renewables on the system selected by the SO model.

Additionally, Sierra Club's argument fails to acknowledge that, as explained in Volume II, Appendix R, Flexible Reserve Study (FRS), of the 2019 IRP, the deterministic hourly modeling required to make the proper assessment necessarily assumes "perfect foresight," in that it lacks the stochastic variation required to serve as a complete proxy for real world conditions. This uncertainty is in fact the basis of the additional capacity held in reserve in actual operations and the basis that the company used to determine its uncertainty requirement. As set forth in the 2019 IRP,

[27] Sierra Club Opening Comments at 10.

> The 500 MW incremental requirement relative to a deterministic forecast of loads, outages, market prices, and hydro generation was established upon review of operational data and with consideration of operational experience. In operations, capacity held in reserve for contingency, forecast error and intra-hour variability is approximately 16 percent of peak load. In the summer months, additional capacity is held in reserve to mitigate risks associated with high volatility in load and resource availability. In 2018, capacity held in reserve that is incremental to the 13 percent planning margin for contingency, forecast error, and intra-hour volatility totaled 295 MW. In 2018, capacity held in reserve to mitigate risk during peak load conditions in the summer months was approximately 241 MW. Combined, these sum to 536 MW. PacifiCorp conservatively adopted the 500 MW figure for planning purposes in the 2019 IRP.[28]

The "unknowns" referred to by Sierra Club are thus not incorporated in the 13 percent PRM, and these unknowns are also not included in the deterministic studies. The uncertainty requirement addresses these facts directly.

Sierra Club makes several additional assertions that the uncertainty requirement must be redundant with factors included in the PRM and/or the FRS, and further questions the calculation of the 500 MW uncertainty requirement as being unsupported on the basis of comparing the 13 percent PRM to a peak need requirement, and on the basis of including considerations of the Energy Imbalance Market. As noted above, however, the PRM is incapable of accounting for the increasingly complex needs of a system which relies heavily on renewables, and this is a shortcoming which the company anticipated and subsequently identified, quantified and mitigated. When the reliability of a portfolio is assessed using a more granular tool with visibility into operating reserves (deterministic runs), the shortfalls are real and readily identifiable. If Sierra Club's argument is accurate that the uncertainty requirement was not necessary, no meaningful deficiencies would have been identified among portfolios in the absence of this

[28] 2019 IRP Volume I at 610-611.

requirement. Instead, the deterministic reliability studies show significant shortfalls in specific years, regions and seasons even if the (necessary) uncertainty requirement were to be excluded.[29]

Contrary to Sierra Club's claim that the reliability method employed by the company is "unsupported," the 2019 IRP uses existing, tested models to measure and correct a readily demonstrable issue, and does so in a way that allows for targeted model optimization to meet specific and quantifiable requirements with flexible resources only when and where necessary. Both the need and the method are therefore well-founded and valid. Nevertheless, PacifiCorp expects that it will continue to refine its reliability resource methodology in the 2021 IRP. The company is exploring alternative model software and techniques that may allow for a more direct assessment of reliability. Further stakeholder involvement will continue to be a valuable component of any future changes to this methodology.

iii. <u>A correction to the Jim Bridger Coal Mine costs is necessary but results in no changes to the Action Plan.</u>

Sierra Club's second critique of the company's coal analysis is that the coal mine costs associated with Jim Bridger are incorrect as included in the preferred portfolio.[30] PacifiCorp reviewed these costs and determined that Sierra Club has correctly identified an error. During the portfolio development process, while correcting for coal mine reclamation cost assumptions, PacifiCorp incorrectly modeled mine capital costs in P-45 based on the "Opt E Mine Plan," under which the Bridger Surface Mine closes in 2022 rather than the "Opt F Mine Plan" under which it closes in 2028. The impact on a PVRR basis is that P-45 is understated by roughly $29 million. Resource planning reviewed all other cases to ensure the correct match of mine capital costs between master assumptions and the model and found no other instances where the

[29] 2019 IRP public data disc, \Public\Assumptions & Inputs\PaR Reliability Summary\P IRP Study Reliability Requirements for SO RP 1 (09252019).xlsx.
[30] Sierra Club Opening Comments at 15.

incorrect mine plan was modeled. PacifiCorp has also reviewed the mine reclamation plan correction to ensure accuracy. In addition, the company has assessed its robust review and validation processes in alignment with the company's commitment to continual improvement.

The impact of this inadvertent error is that under the medium gas/medium CO_2 price-policy assumption as shown in Table 8.14 of the 2019 IRP, correcting for this issue moves P-45CP from the least-cost portfolio to third on a PVRR basis and shifts P-48CP (Jim Bridger 3 &4 retire 2033) to the least-cost followed by P-47CP (Jim Bridger 3 & 4 retire in 2035). However, as closely related variants impacting only the scheduling of Jim Bridger 3 & 4 retirements in the last six years of the study period, cases P-45CP, P-47CP and P-48CP would all yield the same 2019 IRP action items.

If P-48CP had been selected as the preferred portfolio based on the CP-series rankings after the correction in mine capital cost is made to P-45CP, there would be minor variances in limited resource selections within the action plan window. Specifically, the selection of front office transactions and energy efficiency, and a swap of 54 MW of Utah solar with battery storage for the same amount of Utah wind in year 2023. The variances in front office transactions and energy efficiency are arbitrary, with a net portfolio change ranging from zero to 8 MW in each year averaging to less than 5 MW over the action plan window. Portfolio differences remain small through 2029, averaging less than 20 MW.

Sierra Club correctly states that the mine capital cost error makes P-45 less cost-effective relative to other portfolios, including P-36CP (Jim Bridger 1-4 retire 2025), but this does not change the ranking of the initial portfolios. PacifiCorp reviewed all C series and CP series and did not find a misalignment of the mine capital costs in any other case besides P-45. With the mine capital cost correction to P-45CP, case P-36CP remains behind P-45CP in 4 of the 5 scenarios, and remains ahead of P-45CP only in the social cost of carbon scenario. P-36CP remains the least cost-effective case in 3 of the 5 price-policy scenarios, and trails P-45CP by $190 million in the expected case (medium gas/medium CO_2). An additional factor to consider is that the preferred portfolio, P-45CNW, was reduced by $15m in value based on the exclusion of DJ wind (excluded on the basis of heavy curtailments). Cases P-47CP or P-48CP have not had the heavily curtailed DJ wind resource removed, and doing so may be expected to close the already narrow gap by a similar amount. Therefore, the Jim Bridger mine cost correction marginally shuffles the order of closely related cases P-45CP, P-47CP and P-48CP, only in the medium gas/medium CO_2 price-policy scenario, with no impacts to the action plan, and no meaningful net impacts in the front ten years of the study.

Also related to fuel cost assumptions, Sierra Club argues that the company's Bridger fuel cost assumptions were unreasonably low and create a bias in favor of continued operation of these units.[31] The company disagrees. Sierra Club bases its assertion on the costs reported by the company to the Energy Information Administration. The costs reported by PacifiCorp to EIA, however, "includes all costs incurred in the purchase and delivery of the fuel to the plant."[32] The fuel costs included for the Bridger plant in the IRP model are based on a cash cost that excludes non-cash expenses including depreciation, depletion, and amortization. The costs are also net of reclamation costs; these costs are added in as a separate input in the model so that they do not inappropriately influence dispatch costs. Sierra Club is therefore not making an apples to apples comparison and its allegation that a bias exists should be disregarded.

[31] Sierra Club Opening Comments at 19.
[32] Form EIA-923: Power plant Operations Report Instructions at 7.

iv. <u>The company has included industry-standard estimates for solar in its analysis.</u>

In addition to raising specific concerns with the company's operation of its coal units, Sierra Club questioned whether the solar operations and maintenance (O&M) cost assumptions used in the IRP reflect industry-standard estimates.[33] Sierra Club argues that the costs included in the IRP modeling were too high and therefore resulted in fewer coal retirements. In support of its argument, Sierra Club points to Lazard as an industry-standard source. It should be noted that in the referenced Lazard study there is a footnote providing more detail about the costs cited by the Sierra Club: "Left column [$12/kW-yr] represents the assumptions used to calculate the low end LCOE for single-axis tracking. Right column [$9/kW-yr] represents the assumptions used to calculate the high end LCOE for fixed-tilt design." All of the solar resources considered in the company's 2019 IRP are single axis tracking, and therefore fixed O&M costs are expected to be higher than Lazard's low end estimate of $12/kw-yr. The company is confident that its O&M costs for solar were within industry standards. PacifiCorp will, however, continue to monitor cost trends for utility scale single-axis tracking photovoltaic solar generation resources in the company's service territory and update those costs in future IRP cycles. The 2020 renewable resource assessment will specifically address differences from the Lazard and National Renewable Energy Laboratory studies referenced by the Sierra Club.[34]

B. DSM Actions

The company's 2019 IRP separates DSM resources into four (4) classes as follows: Class 1 DSM (demand response); Class 2 DSM (energy efficiency); Class 3 DSM (time varying rates); and Class 4 DSM (customer practice adaptation). In opening comments, several stakeholders raised concerns that the preferred portfolio does not include all cost-effective DSM resources.

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[33] Sierra Club Opening Comments at 23.
[34] Sierra Club Opening Comments at 23.

Staff has specifically requested that the company engage with Staff and other stakeholders prior to final comments in this proceeding to discuss the feasibility of additional demand response (DR) pilots.[35] As discussed below, the company looks forward to additional stakeholder workshops and will plan to work with Staff to design a workshop on the topic of DR pilots; this workshop will be in addition to the technical workshops that are focused on updating the Conservation Potential Assessment (CPA) for the 2021 IRP that are already underway.[36]

The company also agrees with Staff that there could be value in continuing discussions with stakeholders to identify potential improvements to the CPA DR methodology, including how these resources are evaluated with the IRP model.[37] Due to the timing of the CPA development for the 2021 IRP, however, PacifiCorp sees limited additional value in hiring another third-party to review this methodology. Instead, the company will work with stakeholders to consider and address feedback received through the CPA workshops for the 2021 IRP and has started that public-input process earlier in the IRP development process to allow for more meaningful engagement and participation.

i. <u>The company has included an appropriate level of Class 1 DSM resources for Oregon.</u>

It is correct that there is no Class 1 DSM proposed for Oregon in the Action Plan timeframe.[38] The appropriate amount of economic Class 1 DSM resources, however, was selected over the 20 year planning horizon. The preferred portfolio does include incremental Class 1 DSM in most states, including Oregon, within the next ten years, and, over the 20-year

[35] Staff Initial Comments at 35, 37.
[36] The company held the first CPA workshop on January 21, 2020 and a second workshop is scheduled for February 18, 2020.
[37] Staff Initial Comments at 37.
[38] Staff Initial Comments at 32; *see also* CUB Opening Comments at 5 (CUB's Opening Comments state that there is no Class 1 DSM in the preferred portfolio for Oregon but the company assumes that CUB intended to refer specifically the Action Plan).

term, the preferred portfolio includes a total of 444 MW of the 609 MW (73 percent) of achievable incremental summer potential identified in the CPA.[39]

Demand response resources are represented in the SO model as proxy resources after they are developed across the six state service territory within the CPA. The SO model selects economic DR resources based on its ability to compete against other supply-side resources to achieve a least-cost and least-risk portfolio of resources to meet customer needs. The modeling process is robust and continuously improving to ensure the planning process is prudently using the best possible information available at the time of the development of the resource assumptions informing the IRP. Therefore, PacifiCorp's preferred portfolio already identifies the full amount of economic DR within the supply and costs identified in the CPA.[40]

Any questions surrounding the valuation of DR should not hold up the acknowledgement of the company's DSM action items which are also rooted in thorough and time-tested analytics and evaluation. Recent improvements to the modeling practices for DR for the 2019 IRP include the ability to assess programs targeted to deliver ancillary services as well as the application of state-specific transmission and distribution cost credits. For the 2021 IRP, additional improvements to how DSM, including DR, is represented in the model are under development and will be discussed during the CPA stakeholder workshops for the 2021 IRP. The company has extensive DR experience including operation of the "coolkeeper" program in its Utah service territory for nearly 92,000 customers. The company will continue to leverage this experience to implement DSM programs as they become cost-effective.

The company is, however, amenable to discussing NWEC's suggestion to engage in a separate RFP process for DR (separate from the upcoming All-Source RFP and the CPA) to

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[39] 2019 IRP Volume I, Table 9.4.
[40] *See* Staff Initial Comments at 34, 37.

evaluate the market for the acquisition of cost-effective DR resources. This separate RFP will allow for narrowly-tailoring the DR program, including locational and operational characteristics that would not necessarily apply to a generation resource. PacifiCorp suggests that a meeting with interested stakeholders be scheduled to discuss concepts surrounding the scope and scale of such an RFP.

The company is appreciative of this interest and willingness to engage with PacifiCorp to ensure that its modeling is evolving. As part of the 2021 IRP and CPA development, PacifiCorp has two public-input meetings dedicated to CPA development (one was held on January 21, 2020 and one is scheduled for February 18, 2020).[41] In addition to these meetings, stakeholders will have many opportunities for discussion on the 2021 CPA such as reviewing the CPA statement of work and associated measures list during the CPA stakeholder review process. The company is open to having an additional CPA meeting to discuss DSM, including DR, methodologies and assumptions and will schedule a meeting in April of 2020.

ii. The company continues to pursue additional cost-effective DSM Class 2 resources and improvements to its system-wide approach to acquisition of these resources.

Staff and NWEC raise concerns with the level of energy efficiency pursued in Oregon relative to the other company jurisdictions and request additional information to facilitate their review.[42] In response to these concerns, PacifiCorp notes that the 2019 IRP Class 2 DSM selections are economic as determined by the IRP model over the 20-year planning term and have increased from the 2017 IRP (by approximately 6 percent) on a system basis. PacifiCorp appreciates, however, the desire to understand key underlying assumptions in the CPA that drive differences between states. The company will ensure that key drivers of potential are

[41] Information regarding these CPA workshops can be found on the company's IRP, stakeholder input webpage: https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html.
[42] Staff Initial Comments at 40-41; NWEC Opening Comments at 4.

communicated to stakeholders in the April 2020 CPA meeting. In addition, PacifiCorp is investigating alternative approaches to developing potential for Class 2 DSM and has engaged stakeholders to participate in its CPA development process. PacifiCorp is already working on developing alternative bundling methodologies for the 2021 IRP and will work with stakeholders during the IRP public input meetings.[43] PacifiCorp provided the requested energy efficiency peak contribution by region and state on January 24, 2020 in response to a Staff discovery request.[44]

PacifiCorp notes that energy efficiency disparities across its system exist in part due to differences in the potential for each state *(e.g.*, some states have projected load decreases whereas Oregon load is projected to grow) and different requirements that exist for each state (*i.e.*, Oregon and Washington require use of a ten percent NW Power Act Conservation Credit). There are also modeling differences for each state. Utah and Wyoming use utility cost while all other states use total cost for modeling energy efficiency. Finally the load forecasts differ significantly between states and this is a significant driver for the different energy efficiency selections by state.

NWEC has suggested that one way to address these disparities across the company's service territories is to consider implementation of a system-wide energy efficiency plan that would ensure that ratepayers in any one state (*e.g.*, Oregon) are not subsidizing ratepayers in another jurisdiction.[45] The Energy Trust of Oregon (ETO) is responsible for developing the Class 2 DSM potential for Oregon. As noted by Staff, the company has been working with the ETO to

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[43] *See* Staff Initial Comments at 40, 41 (recommending that the company continue to study alternative bundling approaches for future IRPs).
[44] PacifiCorp response to Data Request 127.
[45] NWEC Opening Comments at 4-5.

improve energy efficiency selection;[46] lessons learned from this Oregon Energy Efficiency Forecasting Analysis Report could be leveraged to improve Class 2 DSM targets in the company's other jurisdictions. The outcomes of the analysis performed with the ETO were included with the 2019 IRP[47] and PacifiCorp continues to coordinate with ETO to ensure alignment in methodologies, where applicable and appropriate.

iii. Additional Class 3 DSM pilot programs should be addressed in PacifiCorp's next general rate case.

As Staff correctly notes, Class 3 DSM (time varying rates) are not separately accounted for in the IRP development process.[48] Instead, Class 3 DSM is naturally accounted for through historic load patterns. Staff is concerned that this approach will cease being the most effective method for capturing this resource as the company begins in engage in additional Class 3 DSM pilot programs.[49] Staff has recommended a workshop, before the next IRP process, to discuss how the resource planning process can best reflect Class 3 DSM programs and development of potential pilot programs.[50] Staff notes that this discussion will be particularly relevant as the company increases deployment of advanced meter infrastructure (AMI) throughout its Oregon service territory to determine how best to use the resulting data.[51]

With respect to Staff's interest in collaborating with PacifiCorp to understand how AMI data can be used to develop additional Class 3 DSM programs, the company agrees with Staff

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[46] Staff Initial Comments at 41; on October 26, 2018 the company was directed by the Commission to undertake this assessment and has subsequently been working together with Energy Trust of Oregon.

[47] The ETO Report was filed with the Commission in this docket on April 5, 2019; the report was also presented at the February 21, 2019 public-input meeting. The presentation from that public-input meeting can be found on the company's IRP website: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019-irp/2019-irp-presentations-and-schedule/2019-02-21%20-%20General%20Public%20Meeting%20(conference%20call).pdf

[48] Staff Initial Comments at 42.

[49] Staff Initial Comments at 42.

[50] Staff Initial Comments at 44.

[51] *See* Staff Initial Comments at 42-43.

that AMI creates new opportunities for the company to offer expanded Class 3 DSM offerings for its customers. In fact, PacifiCorp plans to propose several time-varying rate pilots as part of its general rate case.[52] Rate proceedings are the appropriate venue for expansion of and/or introduction of time varying rate options. Resource planning is one consideration surrounding the design of time varying rates, but other considerations such as fixed cost recovery, customer bill impacts and inter-/intra-class cost allocation are also significant. Ratemaking proceedings are best suited to address these diverse and sometimes complex issues.

The company does, however, agree that a workshop to provide an update on the development of these potential Class 3 DSM pilot offerings is appropriate before the 2021 IRP is filed. At that time, and based on the status of the pilot programs, such a workshop will be an appropriate forum to explore how the resource planning process can be improved to either better reflect Class 3 DSM as a load reduction or supply-side resource.

C. Acquisition of New Resources and Transmission Upgrades

As an initial matter, PacifiCorp responds to comments that question the need for additional resources including the resources to be acquired through the upcoming All-Source RFP and the proposed transmission upgrades set forth in the company's Action Plan.[53] For example, AWEC makes the assertion that the need identified in the company's IRP appears disconnected from the proposed RFP and Action Plan (where transmission upgrades are presented). Contrary to these opening comments, the IRP does in fact identify a resource need that is appropriately met through a combination of actions including the All-Source RFP and transmission upgrades.

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[52] As the Commission is aware, the company will be filing a general rate case in February 2020.
[53] *See, e.g.*, NWEC Opening Comments at 10.

AWEC's claim that the 2019 IRP establishes no energy or capacity need until 2028 is incorrect. This statement appears to be a misinterpretation of the following text from the 2019 IRP:

> When accounting for these same factors and the level of potential market purchases, front office transactions (FOTs), assumed in the 2019 Integrated Resource Plan (IRP), PacifiCorp's system is capacity deficient over the summer peak beginning 2028 and is capacity deficient over the winter peak beginning 2029.[54]

This excerpt of the 2019 IRP (plus the text in the preceding two bulleted paragraphs) indicates that the deficiencies are net of "future energy efficiency savings" and the maximum allowable level of "front office transactions (FOTs)" from the preferred portfolio. Energy efficiency and FOTs are competing resources, without which (and in the absence of alternative resources) the system becomes both capacity and energy deficient. In fact, without any incremental resource procurement, PacifiCorp's system is immediately capacity deficient at the time of the summer coincident peak hour (*i.e.*, without market purchases from neighboring utilities or other marketers, the summer capacity shortfall is 746 MWs in 2020).[55] The most basic objective of the IRP process is to evaluate different ways that PacifiCorp can meet a forecasted need, considering all resource alternatives on a comparable basis. The outcome of this effort in the 2019 IRP, supported by extensive economic and risk analysis, has identified a least-cost, least-risk plan to meet near-term capacity deficits that includes energy efficiency, market purchases, new renewable resources, and new flexible capacity resources. As suggested by AWEC, assuming that near-term capacity deficits, affected in part by accelerated coal-unit retirements, will be met entirely with energy efficiency and FOTs would increase customer costs

[54] 2019 IRP Volume I at 97.
[55] 2019 IRP Volume I, Table 1.3.

and introduce incremental risk for PacifiCorp's retail customers. As noted later in the 2019 IRP, resources selected in the action plan period of the preferred portfolio contribute to the sixty percent decline in summer peak FOTs in years 2020-2027 when compared to the 2017 IRP preferred portfolio.[56] This decline is largely driven by the improving economics of renewable resources, displacing FOTs as a mechanism to meet system need. As further noted in the 2019 IRP, this outcome mitigates risk by reducing PacifiCorp's reliance on market purchases over a period where there are regional resource adequacy concerns.

1. PacifiCorp will satisfy the Commission's competitive bidding rules through "track two"

The 2019 IRP action item 2b states that the PacifiCorp will issue an All-Source RFP to meet the resource need discussed above.[57] The company does not dispute that the All-Source RFP will trigger the Oregon competitive bidding rules set forth in Oregon Administrative Rules (OAR) 860-089-010 *et seq*. adopted in 2018.[58] The Commission's competitive bidding rules provide two tracks for approval of the design of an RFP in OAR 860-089-0250. "Track one" contemplates inclusion of a draft RFP as part of a utility's IRP filing with the Commission; under "track one" the Commission would acknowledge a resource need as part of the utility's IRP and simultaneously approve the associated RFP design, scoring methodology, and associated modeling process. "Track two" allows a utility to pursue an RFP outside of the IRP process by seeking approval of the RFP scoring and associated modeling through the independent evaluator (IE) docket.[59] Because the company determined that it might be necessary to issue an RFP prior to the time when an IRP acknowledgment could be received from the Commission, PacifiCorp

[56] 2019 IRP Volume I at 209.
[57] 2019 IRP, Volume I at 24.
[58] *See* OPUC Order 18-324.
[59] Regardless of which RFP track is used, utilities are required to engage an IE prior to issuing an RFP to oversee the competitive bidding process. OAR 860-089-0200(1).

elected to pursue a "track two" RFP process. On December 13, 2019, the administrative law judge (ALJ) issued a memorandum identifying issues for possible stakeholder comment specifically related to this RFP including questions about how the company will comply with the Commission's competitive bidding rules related to RFP design. Several stakeholders commented on the RFP action item, including direct responses to the questions raised by the ALJ in the December 13, 2019 Memorandum. These stakeholders included: AWEC, NIPPC, NWEC, Staff, Sierra Club, and Swan Lake.

In responding to the ALJ memorandum, stakeholders argued that PacifiCorp must comply with the requirements of "track two."[60] The company agrees and has created a timeline for the RFP process that anticipates each component of "track two." Specifically, the company's timeline allows for approval of the RFP scoring and associated modeling as a distinct and separate item from the draft RFP itself in the IE selection docket. The company's RFP is anticipated to be filed for approval with state regulatory commissions during the first quarter of 2020 and issued to potential bidders during the second quarter of 2020.[61] The timeline set forth in the 2019 IRP action plan provides time for regulatory approval of the RFP prior to issuance.[62]

Related, PacifiCorp Transmission is seeking reforms to its' interconnection queue process, which is pending before the FERC. Interconnection queue reform was the subject of multiple workshops over several months with stakeholders in recognition of the impacts that the interconnection queue would have on the RFP process, including how it would be incorporated into the scoring and evaluation modeling procedure (*e.g.*, with respect to minimum requirements

[60] *See, e.g.*, AWEC Opening Comments at 7-8. *See also* Sierra Club Opening Comments at 27 (Sierra Club's Opening Comments do not reference the competitive bidding rules but do assert that the form of the company's RFP should be reviewed and approved by the Commission prior to issuance and that PacifiCorp should be required to engage an IE. As discussed in these comments, the company does not disagree that compliance with the competitive bidding rules is necessary and appropriate; the suggestions of Sierra Club appear consistent with the competitive bidding rules).
[61] 2019 IRP, Volume I at 24.
[62] *See* OAR 860-089-250.

and non-price scoring). As a result, the company opted to present its draft RFP components after the stakeholder process was complete and there was more clarity as to the substance of its proposed reforms. For example, with queue reform, PacifiCorp would not require an interconnection study as a minimum requirement in the RFP because the results of the transition process applied to projects currently in the queue will not be known before bid submissions are due. Without queue reform, however, an interconnection study would continue to be required. Further, while the company will be proposing to use the same screening model from past RFPs and the same IRP model for the RFP, the inputs as well as how and when the models would be used were not certain. Therefore, based on options presented for compliance with the Commission's competitive bidding rules, PacifiCorp determined that "track two" was appropriate and allowed the company to submit its proposed RFP scoring methodology and associated modeling through the IE selection docket with the benefit of additional information regarding queue reform.

Now that PacifiCorp Transmission's queue reform proposal has been filed with the FERC, PacifiCorp's resource procurement function will be able to consider the queue reform filing and make any changes to its proposed RFP scoring methodology and process prior to filing its request with the Commission to open an IE selection docket. This is the most efficient option for complying with the competitive bidding rules, while also using the most current information available. Stakeholders and parties to the IE selection docket will have an opportunity to comment on the RFP scoring methodology and associated modeling, as well as, the complete draft RFP. It is also expected that bidders responding to the IE RFP (*i.e.*, all potential IEs) will have a chance to review and opine on the proposed scoring methodology as part of their bids;

these responses from potential IEs will provide an additional layer of review for the proposed RFP components.

Further, and in response to Staff's request for an explanation of how queue reform will impact the All-Source RFP,[63] the company currently plans to issue the RFP in June 2020. If, by virtue of a FERC order accepting PacifiCorp Transmission's queue reform proposal, those rules have become effective before the issuance of the RFP, the company would issue an RFP that takes those reforms into account. Specifically, under its proposed "transition process," PacifiCorp Transmission would conduct a cluster study of projects in the current queue, but only for those that can demonstrate commercial viability. Because many projects in the current queue will depend on the RFP to demonstrate commercial viability, they cannot know their interconnection prospects before submitting a bid to the RFP. Consequently, if FERC approves the queue reform proposal, the company will allow RFP bids for projects that do not have interconnection studies. This potential change to the bidding requirements has already been communicated by PacifiCorp's resource procurement function through comments posted on PacifiCorp's OASIS website with respect to the ongoing queue reform process.[64] After PacifiCorp's resource procurement function selects the initial shortlist of bidders (based on IRP modeling), bidders will be notified, at which point they will be able to notify PacifiCorp Transmission that they satisfy the commercial readiness criteria for entry into the transition process cluster study.

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[63] Staff Initial Comments at 60.
[64] https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Comments_-_PacifiCorp_Resource_Acquistion_.pdf.

2. PacifiCorp's reply to parties' comments on its upcoming All-Source RFP.

i. Treatment of long-lead time resources.

In addition to the concerns raised about how the company will comply with the competitive bidding guideline requirements, NIPPC and Swan Lake Hydro suggest that PacifiCorp's upcoming RFP allow for long-lead time capacity resources.[65] PacifiCorp recognizes the dilemma faced by long-lead time resources to meet a near-term guaranteed commercial operation date in response to an RFP. For PacifiCorp's All-Source RFP, the near-term commercial operation date of December 31, 2023 is driven by the expected benefit of bidders using federal tax credits for their projects. At the time the 2019 IRP was filed, these federal tax credits have sunset dates at the end of 2023. After the 2019 IRP was filed, federal legislation was passed extending the sunset for production tax credits to the end of 2024, which will be accommodated in the All-Source RFP.

Nevertheless, PacifiCorp would consider certain resource types (*i.e.*, pumped storage) that have historically demonstrated the need for longer permit and construction schedules. Should such a bid be received in response to the All-Source RFP contemplated in the Action Plan, PacifiCorp will evaluate such bid outside of the standard RFP review process based on the 2019 IRP assumptions to determine whether the bid is an economic and prudent option for PacifiCorp to pursue. If the company makes a determination that this long-lead time resource would provide economic benefits and is feasible, PacifiCorp will remove the bid from the All-Source RFP process and pursue the resource subject to a waiver request as required by the competitive bidding rules.[66]

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[65] Swan Lake Opening Comments; *see also* NIPPC Opening Comments at 5.
[66] OAR 860-089-0100(2)(b).

ii. The All-Source RFP will be drafted to acquire resources that meet the need identified by the IRP taking into account all appropriate criteria.

Staff has requested that the company submit an updated action item with an approximate quantity and type (energy or capacity) of the resources that PacifiCorp will seek to acquire through the All-Source RFP.[67] Staff is concerned that there is a lack of specificity regarding what will be procured and that this lack of specificity makes it difficult to tie the All-Source RFP to the 2019 preferred portfolio.[68] PacifiCorp intends to include a topology chart specifying targeted procurement levels by geographical area on PacifiCorp's electrical system that is based on the 2019 preferred portfolio as part of the All-Source RFP. This information is also provided for P-45CNW in Appendix M of the 2019 IRP.[69]

As mentioned above, the company's All-Source RFP will include a topology chart that will identify targeted procurement levels by geographical area. Staff suggested in its opening comments that the company should consider whether a geographic diversity scoring metric should be added to the RFP to help improve the value of new resources on PacifiCorp's system. The company agrees that geographic diversity can add overall system value to any generation value. Importantly, generation asset development is most often predicated on the following factors:

- Cost effective electric transmission interconnection availability and proximity;
- Economic renewable resource availability (*e.g.*, wind, solar, etc.) at the proposed location;
- For fossil generation, fuel delivery infrastructure (*e.g.*, pipelines, rail, etc.) in close proximity;
- Favorable state, county, and local support;
- Permitting with limited anticipated special impacts; and
- Acquisition of land rights under favorable terms and timelines.

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[67] Staff Opening Comments at 59.
[68] Staff Opening Comments at 59; *see also* AWEC Opening Comments (asserting that the company's preferred portfolio does appear have a strong relationship to the company's action plan or resource needs).
[69] 2019 IRP Volume II, Appendix M at 278.

In addition, the 2019 IRP through its preferred portfolio topology, does suggest where on PacifiCorp's system new resources will provide the greatest value. Thus, the preferred portfolio already takes the impacts of generation diversity into account. Over-concentration of any particular type of generation technology can generally reduce its system value in a specific area due to stresses on infrastructure (electric transmission, fossil pipelines, etc.) and creation of regional grid balancing challenges. For example, having an over-concentration of variable renewables with similar generation profiles can create balancing challenges. Therefore, PacifiCorp suggests that these types of considerations have already been accounted for in the 2019 IRP and that the modeling methodology being finalized for the All-Source RFP will be consistent with the modeling approach used during the IRP. Adding a geographic diversity scoring metric is not necessary.

Finally, Staff requested an explanation for how wheeling costs would be modeled in the upcoming All-Source RFP for resources that are not already connected to the PacifiCorp system.[70] Where a bid is received in response to the RFP that requires wheeling, there are two options for how the wheeling costs will be treated based on the bid structure. For a bid where output from a project will be sold directly to PacifiCorp through a power purchase agreement, the cost of moving the power from the project over a third-party transmission provider to PacifiCorp will be the responsibility of the bidder. PacifiCorp would pay the bid price for the power delivered to and received on its system; the bidder would be responsible for all costs associated with delivery of the generation (and therefore it is expected that the bidder would include any wheeling costs in its bid price). The second bid structure option is a build-transfer where the project is developed and constructed by the bidder but then the project is sold to

[70] Staff Initial Comments at 61.

PacifiCorp to own and operate. Under this scenario, PacifiCorp would own the resource and be responsible for the purchase of transmission services to move the power across a third-party transmission system to its own system. In this second scenario, for RFP bid evaluation purposes, PacifiCorp would include the projected costs (including escalation over the life of the asset) of procuring firm transmission service from the third-party transmission provider using the posted transmission service components on the third-party transmission provider's open access transmission tariff (OATT). This process allows PacifiCorp to fully consider all bids, even those not located within its service territory.

3. PacifiCorp's reply to parties' comments on transmission resources.

PacifiCorp's 2019 IRP action plan also includes several transmission action items, including new transmission resources Energy Gateway South, B2H, and Energy Gateway West and several transmission reinforcement projects.

a. Transmission Need

As an initial matter, AWEC, NWEC, Staff, and Sierra Club all raise concerns regarding the need for these transmission investments especially without knowing the results of the upcoming All-Source RFP.[71] AWEC specifically refers to action item 3a (Energy Gateway South) stating that this transmission project is tied to resource acquisitions that are uncertain at this time and therefore PacifiCorp has not provided a sufficient justification for Energy Gateway South.[72]

PacifiCorp does not dispute the resources in the preferred portfolio that are associated with Energy Gateway South are uncertain. AWEC appears to imply that resources associated with a transmission project that is evaluated within the context of an IRP should be procured

[71] *See, e.g.*, AWEC Opening Comments at 4-5; *see also* Staff Initial Comments at 53.
[72] AWEC Opening Comments at 4-5.

before the transmission project should be acknowledged through an IRP process. AWEC's argument is inconsistent with competitive bidding requirements and basic planning principals, and consequently, does not support its recommendation to not acknowledge action item 3a. As discussed above, PacifiCorp plans to issue an All-Source RFP to procure resources identified in the preferred portfolio. This will include resources in eastern Wyoming that would be reliant on the Energy Gateway South transmission line. PacifiCorp will evaluate these proposals through the All-Source RFP and select projects reliant on the Energy Gateway South transmission line to the final shortlist only if those resources and the associated transmission investment are part of the least-cost, least-risk mix of resources relative to other alternatives bid into the RFP. PacifiCorp understands that acknowledgement of an action item is not a pre-approval of that action item. The Energy Gateway South project is an element of PacifiCorp's least-cost, least-risk preferred portfolio and the associated action item should be acknowledged. The company understands that an acknowledged Energy Gateway South action item will not, in and of itself, lead to the construction of this transmission line. The results of the All-Source RFP will determine whether Energy Gateway South and any associated new resources should be pursued.

To tie this transmission need directly to the resource need identified in the IRP, Staff suggests that it might be helpful to add an RFP scoring metric that would evaluate a bidding resource's performance in the most probable Energy Gateway buildout future.[73] While the company appreciates Staff's consideration of how best to ensure that resource acquisitions are informed by available (or expected) transmission capacity, PacifiCorp does not currently support the addition of a scoring metric dependent on uncertain Energy Gateway projects. The 2019 IRP evaluated additional Energy Gateway transmission segments, and while there is potential for

[73] Staff Initial Comments at 53.

future investments in the transmission system, the company found these segments to be uneconomic at this time. The company proposes that generation projects be selected based on price and non-price attributes and that the relative value of a resource dependent upon specific transmission investments be accounted for when establishing a final shortlist. Assets that are capable of creating additional value to a proposed transmission asset would be identified and valued in conjunction with the proposed transmission investment.

To fully evaluate the transmission need identified in the 2019 IRP, Staff has requested that the company address regional needs for western transmission projects and to specifically explain why there does not appear to be any net benefits to PacifiCorp customers from the B2H transmission segment even though the Northern Tier Transmission Group (NTTG) transmission studies suggest that B2H will be important in resolving transmission issues in Oregon by 2026.[74]

The 2019 IRP analysis and the regional planning process performed by the NTTG are two distinctly different processes that address two distinct needs. The IRP analysis specifically focuses on forward-looking resource needs of PacifiCorp including inputs of planned or required transmission upgrades necessary to deliver resources. The NTTG planning process is a transmission reliability analysis using projects submitted by the funding members included in their local transmission planning process to identify the least-cost or most efficient regional transmission plan. Because the NTTG planning process evaluates the entire regional planning footprint of its members, the analysis is much broader in scale than the IRP analysis performed by PacifiCorp. For this reason, it is also not appropriate to rely solely on the NTTG planning process to determine the benefits of a particular project for PacifiCorp.[75]

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[74] Staff Initial Comments at 52.
[75] *See* Staff Initial Comments at 52-53 (requesting the company to explain why the regional value of the Energy Gateway transmission projects as shown in recent NTTG studies are not captures in the IRP analysis).

Staff asks what the likelihood is of the Energy Gateway South transmission segment being required by FERC interconnection or transmission service rules in the near-term. The company's legal requirement to provide non-discriminatory interconnection service is a factor in determining the need for Energy Gateway South. PacifiCorp's OATT and federal law require the company to expand its transmission system to the extent necessary to grant requests for transmission or generator interconnection service. Because Energy Gateway South is part of PacifiCorp's long-term transmission expansion plan, PacifiCorp has already executed several interconnection agreements that depend on Energy Gateway South. Energy Gateway South is considered a "contingent facility" for these signed interconnection agreements. This means that Energy Gateway South being in service was an assumption upon which the interconnection agreement was executed.

b. Endogenous Transmission Modeling

Staff expresses support for the company's endogenous transmission modeling,[76] a significant modeling improvement developed in the 2019 IRP. Staff however, raises concerns regarding whether the model appropriately orders and prioritizes transmission projects in its selection optimization. As noted above, it is important to note that acknowledgment of specific transmission action items does not mean that the company will move forward with these projects without further analysis.[77] The company will continue to update its analysis and only move forward with items that continue to provide a least-cost, least-risk portfolio. However, at the time

[76] Staff Initial Comments at 44.
[77] The company does not view acknowledgement of its action plan as writing a "blank check" to acquire resources as suggested by AWEC. *See* AWEC Opening Comments at 3. The company will acquire resources and move forward with transmission upgrades and projects only if such actions continue to be supported by thorough and robust analysis.

of the 2019 IRP development and filing of these comments PacifiCorp finds that the action items represent the most reasonable path forward.

With respect to the action items, Staff is concerned that the reliability benefits of Energy Gateway South are duplicative of the benefits of Energy Gateway Central (thereby potentially rendering Gateway South unnecessary).[78] Staff specifically questions to what extent Energy Gateway South is tied to Utah reinforcement. In response to this concern, PacifiCorp clarifies that the Utah reinforcements that have been defined within the scope of the Energy Gateway South Project increase the reliability of the central Utah transmission system while also supporting the significant transfer capability of the Energy Gateway South Project. All Utah reinforcements that have been defined within scope of Energy Gateway South were necessary to meet requirements of North American Reliability Corporation (NERC) planning standards.

Staff also asserts that the company has been unable to identify benefits associated with Energy Gateway South that are specific to Oregon customers. Staff states that the company has tied all benefits associated with Energy Gateway South, and specifically its change in timing from 2032 to 2023, to new wind resources in Wyoming without providing any assurances that this new wind will be able to be imported to Oregon.[79] To address this, Staff has requested that PacifiCorp explain why only one in-service date was considered for Populus-to Hemingway (Segment E) and B2H (Segment H) and whether further analysis could provide support for the optimal timing of these segments. As an initial matter, PacifiCorp notes that it plans and operates as a single system. The company does not transfer power from specific resources to loads in specific states. All system resources deliver energy and capacity to support the system as a whole. With respect to Segment H, PacifiCorp notes that Idaho Power is the sponsor of that

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[78] *Id*.
[79] Staff Initial Comments at 48.

project and therefore the timing is driven by Idaho Power. PacifiCorp continues to review benefits and need for Segment E in coordination with Segment H to ensure that maximum benefits are provided to the company's customers. Both projects, however, will be necessary to strengthen the tie between PacifiCorp's control areas and to support moving renewable resources from the east (where they are predominantly located) to the west, including Oregon.

The favorability of the Energy Gateway South transmission segment in the IRP preferred portfolio is based on the fact that the Aeolus-Clover 500-kV line will increase transfers out of eastern Wyoming to central Utah by 1,700 MW, thereby providing increased access to higher levels of renewable generation to the Utah Wasatch Front. While B2H will increase transfers between Idaho and the Pacific Northwest, the availability of Wyoming renewable resources to the Pacific Northwest will be limited to the existing east to west transfer levels across Idaho until remaining portions of Energy Gateway West between Jim Bridger Power Plant (Anticline) and Hemingway are constructed. As a comparison, while Energy Gateway South is estimated to be a 414 mile line, the distance from Jim Bridger/Anticline to Hemingway/Boardman is estimated to be 767 miles including 477 miles between Bridger/Anticline to Hemingway and 290 miles from Hemingway to Boardman.

The company is unable to provide any comments in response to Staff's request to report on the possibility of completing B2H in 2024 to pair with PTC wind located near the Western Balancing Authority Area. Idaho Power is the project sponsor for B2H and has identified the expected in-service date and what is achievable based on permitting and construction timelines. As a participant in the permitting phase of the project, PacifiCorp cannot control the in-service date.

Finally, Staff requests clarification for how the company is allowing new resources to be modeled as connecting with the proposed new transmission segments (including whether wheels are assumed).[80] For IRP modeling of resource additions in Eastern Wyoming, renewable resources were assumed to be added in the Aeolus Area between Shirley Basin and Standpipe. This resource location would fully load Energy Gateway West Segment D.3, E and H (across Wyoming and Idaho to the Pacific Northwest) and Energy Gateway South, Segment F (across Wyoming and Utah to central Utah). Any resource additions north of the Aeolus Area in the Dave Johnston/Windstar Area would trigger the addition of Energy Gateway West, Sub-segment D.1. Eastern Wyoming resource additions were selected based on the Large Generation Interconnection (LGI) queue order. Without adding the defined Energy Gateway transmission segments, resource additions would have resulted in violations of NERC planning standards.

Finally, Staff seeks clarification on whether the recently issued FERC Order in Docket Nos. ER19-2760-000 et al. changes the company's recommended action items. This recent FERC order rejected the filing that would have created a single regional transmission planning region-NorthernGrid and replaced the existing NTTG and ColumbiaGrid planning processes. The order outlined deficiencies in the filing, provided guidance, and rejected the proposal without prejudice. Revised filings (Attachment Ks) were submitted on January 28, 2020, which incorporated changes based on the guidance provided by FERC. The filing parties requested that FERC accept the revised Attachment Ks effective April 1, 2020. The regional planning process, as proposed, would not change how projects are proposed into the regional plan or who can propose projects. Under the NTTG planning process, the Energy Gateway West Segment D

[80] Staff Initial Comments at 53.

(including D.1, D.2, and D.3), Segment E, and Segment F were selected into the Regional Transmission Plan as being the most efficient or cost-effective plans.

Under the proposed Northerngrid process, regional transmission planning occurs over a two year planning cycle beginning on January 1 of each even numbered year. Under the process, merchant transmission developers such as LS Power, TransWest Express or NextEra have meaningful opportunities to propose projects for inclusion in the regional transmission plan. With respect to Staff's related questions regarding how the company will control costs associated with transmission projects,[81] PacifiCorp's Energy Gateway Projects have a robust competitive element to the construction of the projects and are designed to meet defined cost, schedule and quality parameters. Within the construction phase of projects, all major contracts are competitively bid, providing the lowest cost solution at the time of the bid. PacifiCorp requires the competitive bidding process to be open to qualified bidders, and through a defined quality control process, awards any eventual contract to the lowest bidder that meets the design criteria.

D. Inclusion of QFs in the Preferred Portfolio

1. PacifiCorp's treatment of QF contracts in the preferred portfolio is consistent with Commission precedent and reliability needs.

PacifiCorp's modeling of QFs in its preferred portfolio assumes that QFs will not renew their contracts at the conclusion of the existing QF contract term, similar to how they were modeled in PacifiCorp's 2017 IRP. In opening comments, REC raised concerns with this method. Specifically, REC recommends that Commission decline to acknowledge PacifiCorp's assumptions and instead direct the company to change these assumptions such that all QF contracts are expected to renew (or that the QFs will enter into a new contract at the conclusion

[81] Staff Initial Comments at 74.

of their existing contract).[82] Staff suggests that the company update its preferred portfolio to include a forecast of new QF capacity that reflects historical trends asserting that the uncertainty regarding QF capacity is not a reason to forecast no QF capacity.[83]

While the company understands REC and Staff's arguments that it could be appropriate to include some level of QF capacity because many QFs do renew or negotiate a new contract at the conclusion of their existing contracts, PacifiCorp cannot require a QF to renew (or execute a new agreement) which would make their inclusion problematic from a planning perspective. In addition, it is important to note that the IRP is prepared on a two-year cycle and includes all QF power purchase agreements (PPAs) that have been executed even if the projects are not yet on-line as long as the projects are expected to reach commercial operation within the IRP planning period (based on information from the QF developer). Trying to include additional QF capacity based on historical trends could lead to unreasonable or misleading results. For example, during the period 2013 to 2019 PacifiCorp executed new or renewal PPAs ranging between 84 MWs in 2019 and 209 MWs in 2014. These are the projects that are either currently operational or under construction. However, during this same time period PacifiCorp terminated over 400 MWs of new QF PPAs because the facilities were never built. A forecast based on historical trends could erroneously estimate the number of QF PPAs in the IRP. Further, historical trends are almost certainly not a reasonable predictor of future QF development activities, which are influenced by a broad range of complex factors. Instead, the company continues to assert that using the best available data based on actual contracts in the most appropriate incorporation of QF capacity when developing an IRP.

[82] REC Initial Comments, at 9.
[83] Staff Initial Comments at 13.

These suggestions would also have cost implications. The Public Utility Regulatory Policies Act of 1978 (PURPA) is designed to compensate QFs based on the avoided costs of the resources that a utility would otherwise acquire. This compensation determination is made at the time that a QF contract is signed; the resource a QF is allowing a utility to avoid changes over time. As a result, if all QF contracts were assumed extended in the preferred portfolio it would not be possible to discern the replacement resources. REC has raised this concern in prior IRP processes and QF contracting dockets; in response to a Commission directive from its 2017 IRP, the company performed a sensitivity that assumed that expiring QF contracts were assumed to continue indefinitely.[84] PacifiCorp is open to continuing to explore the potential impacts of expiring QFs on its IRP process. 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).[85] While IRP models may be a tool to help determine the appropriate capacity value of QF contracts the IRP process is not the appropriate venue for exploring the compensation and contracting practices of QFs. Instead, the company suggests that the appropriate places to explore this issue is within the following pending Commission proceedings: Investigation into PURPA Implementation (UM 2000), Generation Capacity Investigation (UM 2011), or (as suggested by Staff) in the Investigation into the Treatment of QFs in the IRP process (UM 2038).

2. Determining QF compensation is not appropriate in this proceeding.

In addition to arguments regarding QF contract renewal in PacifiCorp's IRP assumptions, REC asserts several suggestions regarding improvements to determining QF compensation.

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[84] This sensitivity analysis was provided to REC in the response to Data Request REC 4.
[85] REC Initial Comments, at 8.

While the issues may be related, any changes to QF compensation policies should be undertaken as part of the pending PURPA investigation docket (UM 2000) or capacity investigation docket (UM 2011). Avoided cost methodology, *i.e.*, compensation for QFs, is already an item for consideration in docket UM 2000. It would be most efficient to defer this discussion to that proceeding. The company notes that REC has been actively participating in UM 2000 and is therefore in no way prejudiced by this suggestion.

Further, there is nothing problematic with the current method for compensating QFs. By not including any assumption regarding QF contract renewal in development of the IRP, when an existing QF does renew its contract it will receive the same capacity payment that would be received if it were a new QF. This is appropriate and consistent with the Commission's Order issued in UM 1610.[86]

E. Responses to Individual Party Comments

In the sections above, the company has provided responses to categories of topics that were raised by multiple parties or that appear to be central to a party's position (*e.g.*, REC's primary concern with PacifiCorp's IRP appears to be the assumptions related to QF contract renewal). In the section below, the company provides responses to the remaining issues presented in opening comments.[87]

1. Securitization

Sierra Club raises concerns that PacifiCorp may be influenced in its decision making process to retire coal resources by the risks for disallowance for remaining asset balances.[88] As an initial matter, PacifiCorp states that cost recovery of remaining asset balances has not

[86] Order 16-147 at 19.
[87] The company's silence with respect to an issue raised in initial comments should not be viewed as agreement with a party's position; as noted above, the company anticipates that some issues will be resolved through workshops or additional discussions between the parties and PacifiCorp.
[88] Sierra Club Opening Comments at 23.

influenced PacifiCorp's analysis of coal retirements. As a means to address this issue, Sierra Club argues that PacifiCorp should consider the benefits of securitization. Sierra Club explains that securitization is a mechanism that several states have adopted that provides ratepayer-backed bonds. The mechanism extends the repayment period for ratepayers while also reducing the return on investment (resulting in savings for ratepayers) while returning outstanding capital to the utility.[89] Sierra Club points out that the company is not authorized to securitize its remaining coal assets in Utah or Oregon.[90] While the company has explored this option as related to the unrecovered net book balance for its existing coal plants, securitization presents a unique challenge for a multi-jurisdictional utility like PacifiCorp. Unless all six states in which the company operates enacts securitization legislation and the corresponding commissions issue financing orders, the company cannot move forward. Legislation in all six states is necessary because, in general, all six states are currently allocated costs and benefits associated with PacifiCorp's coal-fired resources.[91] As such, unless any individual state is willing to securitize the full net book value of a coal-fired resource with ratepayers in that state supporting the bonds, as opposed to only that state's share, PacifiCorp could face a scenario in which only a portion of a coal-fired resource is securitized. This partial-securitization scenario dramatically limits the beneficial application of securitization for PacifiCorp.

In addition, PacifiCorp has identified several other risks associated with securitization through its discussions with financial institutions. These risks include the following:

- The upfront costs typically make transactions sized below $250 million and $350 million uneconomic;
- A special purpose, bankruptcy remote subsidiary of the utility must be created to protect the revenues to the bond holders, adding cost to the overall project;

[89] Sierra Club Opening Comments at 24.
[90] *Id.*
[91] Washington uses a unique interjurisdictional cost allocation methodology that does not recognize the costs or benefits associated with the majority of PacifiCorp's coal-fired resources.

- The utility must establish the irrevocability of the financing order and the state may not take or permit any action that impairs the value of the security property;
- Asset backed securitization transactions generally result in a bond coupon equivalent to that of a single A rated corporate bond although the bonds themselves are generally AAA rated;
- The threat of technological disruption (*e.g.*, customer adoption of self-generated renewable energy and distribution generation) may cap tenor of bonds; and
- Rating agencies may have concerns about shrinking number of ratepayers in the 20+ year horizon.

With these risks in mind, the company will continue to monitor proposed securitization legislation to take advantage of any opportunities that may arise.

2. *Load Forecast Methodology.*

Staff raises several concerns with the load forecast used in the 2019 IRP. As an initial matter, Staff claims that all other regulated utilities under the Commission's jurisdiction provide Staff and qualifying intervenors with access to the load forecast model equations but that PacifiCorp has declined to provide this information.[92] Staff recommends that the company provide an update on the steps taken to provide this access for future IRPs.[93] Staff also specifically requests information regarding the following: (a) the metric used to determine an improvement in load forecast accuracy; and (b) how future load from transportation electrification (*i.e.*, electric vehicles) is captured in the company's load forecast.[94]

First, the company agrees that there is room to increase the transparency of its IRP process with respect to the modeling used to develop its load forecast. PacifiCorp will continue to provide stakeholders with regression coefficients and underlying data; the company will also

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[92] Staff Initial Comments at 14, 15.
[93] *Id*.
[94] Staff Initial Comments at 17 and 19. Staff also recommended that the company attempt to identify and document the source of any data abnormality whenever using indicator variables in a regression. The company notes that it makes every effort to investigate abnormalities in the underlying data and correct these abnormalities rather than using indicator variables. However, there are certain instances where the root cause of the abnormality has not yet been identified and due to time and data constraints PacifiCorp is left with no recourse other than to exclude the outliers from its regression analysis.

begin providing the general form of its model equations in future filings. This will strike the appropriate balance between transparency and protection of PacifiCorp's business interests, which is to ultimately protect the interests of customers. The company also expects to continue engagement with stakeholders on these issues of how best to facilitate stakeholder review where competitively sensitive business information must be protected.

With respect to the metric used by the company to improve its load forecast accuracy, PacifiCorp adopted a differenced model approach for the 2019 IRP residential customer forecasting methodology. This differenced model predicts the monthly change in number of customers instead of directly forecasting the number of customers (like previous IRP modeling). This approach was adopted to correct for an issue common to time-series regression, known as nonstationarity. As pointed out by Staff in their final comments filed in response to PacifiCorp's 2017 IRP, the company's residential customer models were not stationary when not being corrected by autoregressive terms.[95] There are two standard ways to correct for nonstationarity. The first is to find an independent variable that captures the trend and cointegrates with the model to capture the growth trend and allow the regression techniques to function properly. The second is to model the change in data over time using a differenced model.

The company conducted a back-cast analysis using standard regression models, as well as differenced models, for each economic variable. PacifiCorp compared the one-year ahead and two-year ahead forecast using the metric of "mean absolute percentage error" (MAPE) for each approach against actual customer counts. Based on the improvement observed in the stationarity and the MAPE for the differenced model, the company incorporated the new models for the 2019 IRP load forecast.

[95] LC 67, Final Staff Comments at 37.

With respect to transportation electrification in the load forecast, the company did not explicitly incorporate a forecast of electric vehicles (EV) into the 2019 IRP. However, EV load is currently captured and reflected in the load forecast that informs the 2019 IRP because historical sales to EV owners inform the actual sales used within the load forecast. Thus, the load forecast used for the 2019 IRP development projects EV adoption consistent with observed historical EV adoption throughout the company's service territory. In recognition of the potential for future, accelerated growth, the company is currently developing an explicit forecast of EV load growth within its service territories that will be incorporated into future IRP development.

3. Private Generation

As Staff points out in their opening comments, the company has included a forecast for the adoption of private generation (PG) over the planning horizon. The forecast was updated by Navigant. Staff requests clarification on several components of the forecast as follows: (1) Staff requests an explanation of how the company's market penetration models are reflecting the potential for PG adoption over the planning horizon; and (2) Staff requests an explanation for how the company is considering distributed storage technologies.

The company finds that analyzing the potential adoption of PG through the lens of customer economics is an accurate way to estimate adoption over the 20-year IRP planning term. It is true that in the short-term public policies, incentives and customer convictions may drive surges in participation. However, in the long-term, trends in adoption will be based on overarching economics of a potential investment. As a result, and based on the diversity within its service territory, the company determined that an economic focus was an accurate view for long-term planning related to private generation adoption.

The company agrees with staff that customer-sited storage technologies could impact the volume of energy the company delivers to PG customers and in turn, could have implications on their contribution to peak. The company did not specifically build considerations related to customer-sited storage technologies into the 2019 IRP but instead focused on building out its understanding of storage more generally including utility-scale storage. This decision was based on the uncertainty associated with how customer-sited storage would impact loads when the adoption of a technology is in such a nascent stage. At the time of the development of the 2019 IRP, there were only 54 customer-sited storage installations with a discharge capacity of less than 1 megawatt in aggregate installed in the company's six-state service territory.

Finally, in response to Staff's recommendation that the company demonstrate whether policy drivers were appropriately considered in the Navigant PG study, the company declines to speculate on specific policy drivers that are not identified and that would necessarily differ by state. The Navigant PG study uses the current regulatory structure and existing incentive structures, whether ratepayer or tax-payer funding, in each state to develop the base projections. Navigant then adjusts assumptions in developing the high case in such a way that positively impacts the economics of PG from the customer perspective. These assumption modifications impact the model in the same way that a state-specific policy would.[96]

***4.* Economic Opportunity**

On December 20, 2019 (after the filing of the 2019 IRP), the federal government signed the Further Consolidated Appropriations Act of 2020 extending the production tax credit (PTC) by one year. Staff requests that PacifiCorp re-run its preferred portfolio to reflect the PTC extension. The 2019 PTC legislation allows for projects that begin construction in 2020 and achieve operational status before December 31, 2024 (modeled as January 1, 2025) to receive a 60 percent PTC benefit. The 1,920 megawatts of new wind enabled by the transmission and

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[96] The high Navigant private generation forecast was used to develop the High Private Generation Sensitivity (S-05. Results from that sensitivity can be found in the 2019 IRP, Volume I at 267.

identified in the 2019 IRP preferred portfolio would also qualify for 60 percent PTCs, with an in-service date of December 31, 2023. In light of this legislative change and in response to Staff's request, PacifiCorp re-ran its preferred portfolio. The re-rerun of the preferred portfolio resulted in the incremental addition of 2,130 megawatts of wind in 2025 located at Goshen, Idaho (450 MW), Utah (300 MW), Southern Oregon (500 MW), and Yakima, Washington (395 MW). The re-run of the preferred portfolio reported a PVRR(d) benefit of $517 million resulting from incorporation of the 60 percent PTC wind credit that increased the value of previously selected Energy Gateway South wind and also created incentives for wind to be selected by the SO model compared to the preferred portfolio under a medium gas and medium CO_2 price-policy scenario. These findings would not influence PacifiCorp's 2019 IRP action plan, which seeks to issue an All-Source RFP to procure new resources over the near term. These results do highlight that new wind resources offering bids into that All-Source RFP may be more competitive.

5. Supply Side Resource Modeling and Planning

Staff correctly notes that the company removed a wind resource from the Dave Johnson brownfield site beginning in 2028.[97] The company made this decision based on the forecast curtailment for the site that would result in a decreased capacity factor. In its opening comments, Staff state that they continue to assess whether this was an appropriate planning decision asserting that there could be options to store or convert excess wind energy by 2028. To assist its review, Staff requests that the company re-run the preferred portfolio with an update that allows wind plus storage at the Dave Johnston site.

[97] Staff Initial Comments at 28.

The company performed this model run at Staff's request but reflected a wind plus storage option at Dave Johnston upon retirement end of 2027; the results are presented in the table below.

Case	Resource Options			Stochastic Mean	
	WYSW Stand-alone Battery Option	DJ Stand-alone Wind Option	DJ Wind + Storage Option	PVRR ($m)	PVRR(d) from Preferred Portfolio ($m)
Preferred Portfolio P-45CNW	✓	-	-	23,207	-
P-45CP	✓	✓	-	23,192	(15.2)
A19-PPWDS-MMR	✓	✓	✓	23,192	(14.9)

The preferred portfolio wind projects do not include an inherent federal tax incentive for co-location with storage, unlike solar. There is no meaningful difference between providing stand-alone wind and storage proxies as compared to providing a combined proxy for wind and storage where they are co-located. In portfolio P-45CP, stand-alone proxies for both wind at Dave Johnston and storage in Wyoming yielded a portfolio that selected each and resulted in a $15 million increase in benefits on a PVRR(d) basis over the preferred portfolio.[98] Staff's requested study included co-locating wind plus storage that yielded a portfolio result that is relatively the same, with a PVRR(d) benefit of $15 million relative to the 2019 IRP preferred portfolio. Storage selected at the Dave Johnston location was 91 megawatts or 15 percent out of 620 megawatts, with the remaining amount selected as wind.

[98] See 2019 IRP Volume I, Chapter 8.

6. Distributed Generation

Staff's initial comments request that the company report on the feasibility of contacting its customers to gauge interest in a distributed standby generation agreement and if such interest should exist, to report back to the Commission on the viability of implementing such a program.[99] PacifiCorp has initiated discussions with a small number of customers in Oregon to evaluate interest in participating in a distributed standby generation program. These customers expressed interest in the concept of such a program and are willing to evaluate their potential participation if and when a specific program design is presented by the company.

As part of PacifiCorp's process to evaluate the viability of a distributed standby generation program, PacifiCorp is researching the engineering and technical infrastructure necessary for the company to dispatch customer-owned equipment. In addition, the company is evaluating the environmental impacts and requirements, and also researching potential strategies for mitigating these impacts. As the process matures, the company will begin to develop a program design that can be communicated to customers to gauge their potential level of participation.

7. Regional Capacity Adequacy

Staff correctly notes that the preferred portfolio contains no new capacity additions on the West side of PacifiCorp's system but that 325 NW of nameplate capacity are planned for installation on the East side of PacifiCorp's system before 2024.[100] Staff cites to recent Western Electricity Coordinating Council (WECC) regional forecasts that predict a capacity deficit without new resources in the region and asks the company to comment on whether its preferred portfolio is safe and reliable.

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[99] Staff Initial Comments at 31.
[100] Staff Initial Comments at 55.

Consideration of potential system deficit risks (by region, year, and season) are an integral component of the company's reliability assessment, which includes the evaluation of all west side (as well as east side) requirements and resources on an hourly basis for 16 of 20 model years, including a west side allotment of the 500 MW uncertainty requirement, described in Volume II, Appendix R (Coal Studies). The 2019 IRP also assumes a conservative limit for front office transaction availability by region and by season.[101] IRP modeling considerations are informed by an assessment of WECC history, requirements and risks all of which are detailed in the 2019 IRP.[102] Taken together, the 2019 IRP incorporates a robust analysis of WECC risks as a necessary component of the development of its preferred portfolio to ensure that a reliable mix of resources is selected.

Related to the discussion above, Staff have asked for clarification on what transmission investment and queue management reforms underlie the company's assumption that 895 MW of solar with 124 MW of battery can be built and online in Oregon and Washington by 2024 without also addressing existing transmission and interconnection bottlenecks. These concerns are addressed through the IRP model which evaluates various forms of economic re-dispatch, including curtailments and market transactions to identify least-cost options that meet hourly load service requirements throughout the twenty-year resource planning horizon. Interconnection procedures for QFs do not evaluate forms of economic re-dispatch but instead must consider the ability to deliver the aggregate of generation in a local area to the aggregate of load on the transmission provider's system. This narrower look under the OATT procedures does not provide for the same flexibility that a resource operator or purchase may have in making decisions for their economic reasons on a real-time basis. The company also notes that the

[101] 2019 IRP Volume I, Chapter 6 (Resource Options) at 170.
[102] 2019 IRP Volume II, Appendix J (Western Resource Adequacy Evaluation).

battery component of the combined solar plus storage resources are not at issue with regard to transmission bottlenecks because batteries do not create capacity or energy and are assumed to operate within relevant transmission constraints.

8. **Emerging Technologies**

As recognized by Staff's initial comments, the company included an appendix related to its smart grid investments. Staff is correct that the originally-filed Appendix E was not the updated version. PacifiCorp updated the Smart Grid Appendix E and filed it as part of its first supplemental filing on October 25, 2019.

With regard to Staff's question on the status of the Western Interconnection Synchrophasor Project (WISP) post-Peak Reliability, it played an important role in implementing and progressing one of the first widespread uses of real-time measurement of phasor data quantities to evaluate behavior of the integrated transmission grid immediately following significant system disturbances. Efforts by WECC and Peak Reliability members in the WISP helped lead to the development of new national standards, including NERC MOD-033-1, effective July 1, 2017 and NERC PRC-002-2, effective July 1, 2016, that added requirements to all transmission owners and transmission operators, not just those in the Western Interconnection, to install and use these devices to evaluate disturbance events and benchmark system models. RC West has assumed the communications infrastructure that was previously associated with Peak Reliability's Western Interconnection Synchrophasor Program network and will continue to coordinate exchange of phasor measurement unit data quantities in its role as Reliability Coordinator.

With respect to benefits that the company expects to gain from AMI throughout its multi-state system,[103] PacifiCorp will leverage the AMI systems installed in Oregon and California to continue to identify operational efficiencies for meter reading. Additionally, the company will explore possibilities to leverage the infrastructure for non-metering applications including distribution automation, volt-var management and other ancillary benefits. The company has begun exploring using the data derived from the meters to improve operational efficiencies including outage response, distribution transformer management and theft detection through advanced data analytics. As new data-driven use cases are tested and proven in states with AMI, the cases will be expanded across the system as AMI becomes more widely available. PacifiCorp will take the lessons learned in the test state and apply them across the business where the actual costs and benefits will become state-specific.

9. Customer Preference Resources

Staff's initial comments state that the 2019 IRP includes thoughtful consideration of the role that voluntary customer actions will play in meeting PacifiCorp's long-term resource needs but requests clarification regarding how the company will provide customer preference options in Oregon, and specifically, whether the company will file a voluntary renewable energy tariff (VRET) proposal in Oregon.[104]

Customer voluntary bulk renewable energy certificate (REC) purchases under Oregon Schedule 272, when paired with a new resource under a PPA allows the customer to directly support the development of renewable energy *incremental* to resources identified in PacifiCorp's IRP action plan. This is an offering under the "Blue Sky Select" program. Much like other voluntary renewable energy programs, the additional financing secured through the purchase of

[103] Staff's Initial comments at 57.
[104] Staff Initial Comments at 63-64.

the RECs allows the customer to effectively "buy down" the cost of the PPA(s) to enable the development of a new, specified renewable resource(s). Valuation of the resource(s) relies on IRP modeling and analysis to ensure that the resource addition results in a net benefit to all customers from a system net power cost perspective.

This structure is an effective mechanism that not only protects customers from potential cost shifting, but benefits all customers by lowering overall net power costs. Incremental costs of the new renewable energy resource are isolated to the customer that voluntarily pays the above-market costs. This mechanism achieves additionality—which is one of the fundamental value propositions of this voluntary program. Customers who enter into this mechanism of a Blue Sky Select contract do so voluntarily with full transparency into the methodology of how the REC price is derived, and overall terms are offered to the customer to accept or reject. The separate PPA costs are evaluated in a traditional net power cost recovery case (*e.g.*, Oregon's transition adjustment mechanism) and are evaluated alongside all other net power costs. This structure under Blue Sky Select builds on existing voluntary Blue Sky renewable energy programs that have been among leading programs in the nation based on customer participation and satisfaction.[105] This new approach under Blue Sky Select offers the improvement over existing programs by offering interested customers the opportunity to demonstrate clean energy leadership by enabling additionality to the grid (not just supporting resources that are already in service) and lowering costs for all customers.

Due to customer interest and the simplicity of this existing approach, PacifiCorp has no near-term plans to file a separate VRET.

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[105] See National Renewable Energy Lab, Utility Green Pricing Program data available at https://www.nrel.gov/analysis/assets/pdfs/top-ten-utility-green-pricing.pdf.

On a related note, Oregon Staff requested clarification for how implementation of customer preference programs in other jurisdictions-specifically, implementation of the Utah Schedule 34 program and Utah House Bill (HB) 411, will be conducted in a way that will limit the impact on Oregon customers.[106] Staff's initial comments state the IRP analysis indicates an impact of these programs on Oregon ratepayers and Staff seeks clarification on this impact.[107] Implementation of Schedule 34 in Utah will not impact Oregon ratepayers (or ratepayers in any other state). For new customer load that contracts under Utah Schedule 34, the new load is accompanied by new resources to serve the load. For inter-jurisdictional allocation purposes, both the load and the new resource will be excluded from inter-jurisdictional allocations similar to resources behind the meter.

By treating new load in this manner, other states will not benefit or be harmed by the new Utah load. Any load above the resources procured by the customer will be included in Utah's load for allocation, just like other load, and Utah's allocation will increase to cover the incremental load. For existing customers that contract under Utah Schedule 34, the load will continue to be included in Utah for calculating allocation factors, which will prevent cost shifting between states. Under the Utah Schedule 34 rates, these customers continue to pay their retail service rates plus will pay the incremental costs of the renewable resource, which helps ensure that these customers do not shift costs to other customers in Utah (or other states). For Oregon, the new Utah Schedule 34 resources will not be included in the transition adjustment mechanism and the resource cost will be adjusted out of the actual net power costs. This treatment is similar to how Oregon-specific resources such as Black Cap and Old Mill Solar are treated in other states.

[106] Staff Initial Comments at 66.
[107] Staff Initial Comments at 66.

Regarding Utah House Bill 411, the specific program details and ratemaking treatment are still under development; however, the company expects a similar protection against cost-shifting to other states for the program. The legislation itself requires that the commission must find that the rates under the program will not result in any shift of costs or benefits to any nonparticipating customer.

Staff also expressed interest in how the Oregon Community Solar Program (CSP) is accounted for in IRP modeling.[108] Staff is correct that the 2019 IRP does not account for any generation from the CSP. Due to the uncertainty related to the capacity, interconnection timing, and other regulatory issues associated with the current stage of the CSP potential resources, they were not included in the 2019 IRP. As projects begin to interconnect to the company's system, PacifiCorp will incorporate these resources into future IRP planning processes. Going forward, the company expects to have the benefit of actual data from the CSP to develop a forecast.[109]

***10.* RPS Compliance**

Action item 6a states that PacifiCorp will pursue unbundled RECs to meet state renewable portfolio standards (RPS); this action item also states that the company will issue RFPs for then-current-year unbundled RECs to meet California and Washington RPS obligations. Finally, as set forth in action item 6b, the company intends to maximize the sale of RECs that are not required to meet state RPS compliance targets. Staff has requested clarification regarding the company's proposed management of its RECs and potential sales of RECs as identified in this action item.

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[108] Staff Initial Comments at 65.

[109] *See* AR 603, Order No. 17-232, at 13 directing utilities to develop forecasts using data from actual community solar developments.

The company's statement that it will maximize the sale of RECs not required to meet its RPS targets was intended to convey that the company may sell RECs from its Rocky Mountain Power states that do not have RPS obligations. The company is amenable to revising actione item 6b to reflect that only RECs from states without RPS compliance obligations will be sold (if any). The new language would read: "[m]aximize the sale of RECs in Rocky Mountain Power states that are not required to meet state RPS compliance obligations." PacifiCorp also clarifies in response to Staff's question regarding whether the company intends to use its REC bank (or sell all unused RECs) that it has no plans to sell any Oregon-allocated RECs. In states with RPS compliance obligations, the company retains all RECs in excess of RPS requirements to ensure future compliance and avoid future, higher costs of such compliance. PacifiCorp also retains RECs in excess of RPS requirements to comply with new environmental obligations (*e.g.*, the recently enacted Washington Clean Energy Transformation Act which includes additional renewable energy targets).

***11.* Long-Term Planning Topics**

In Section 11 of their Initial Comments, Staff make several requests for additional information related to topics they identified as "long-term planning."[110] These topics are climate adaptation, carbon dioxide emissions forecast and green first mortgage bonds. The first item, a climate adaptation plan, is suggested for the company's next IRP cycle. Staff's definition of a "climate adaptation plan" is not clear. Absent further clarification, the company would defer development of such a plan and its relationship to the 2021 IRP until further discussions can be facilitated with the Commission. Development of requirements to include climate adaptation measures are likely better suited to a Commission rulemaking or working group instead of a

[110] Staff Initial Comments at 69.

utility-by-utility directive through integrated resource planning. Additional process would allow for a holistic approach and engagement with all interested stakeholders.

The second long-term planning topic is a request for PacifiCorp to present an emissions forecast in its preferred portfolio that would be subject to discussion with stakeholders. PacifiCorp's emission forecast for the preferred portfolio was included as Figure 1.12.[111]

Finally, Staff has asked PacifiCorp to discuss whether there are potential barriers to implementing green bond tranches and any benefits to issuing green bonds for upcoming renewable infrastructure, including how low-cost financing for renewable resources could affect IRP portfolios.[112] PacifiCorp is currently evaluating the issuance of green bonds in its upcoming long-term debt financings as a result of its $3 billion Energy Vision 2020 construction program. The company evaluated the use of green bonds in its $600 million July 2018 and $1 billion March 2019 long-term debt issuances, however, given the timing of those capital spends combined with the timing of the coal studies and the 2019 IRP, PacifiCorp determined that issuing a green bond would be viewed more positively in the debt markets only once the 2019 IRP was made public and the capital spend on the Energy Vision 2020 program was significantly complete.

The green bond market has grown from $12 billion in cumulative issuances in 2013 to approximately $600 billion in cumulative issuances in 2019. However, the ability to quantify savings as a result of issuing a green bond are challenging. In conversations with underwriters on the subject of green bonds, many of the large investors are increasing their green portfolios but it is still a fairly small percentage of the total market and very few investors are green only

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111 2019 IRP Volume I, at 14: Figure 1.12-2019 IRP Preferred Portfolio CO_2 Emissions and PacifiCorp CO2 Emissions. The requested Oregon allocated emissions for the preferred portfolio will be provided as first supplement to Data Request OPUC 32 in this docket.
112 Staff Initial Comments, at 70.

investors. In addition, issuers of green bonds are increasingly being asked to provide assurances that the monies spent are used on projects or assets that benefit the environment. This suggests that investors are becoming more discerning in their approach to investing in green bonds. For PacifiCorp's first green bond issuance the company wanted to ensure clear visibility of historical renewable spend and a path to continued environmental stewardship with the 2019 IRP.

IV. NEXT STEPS

On November 13, 2019, the company filed a notice indicating that it will not be filing an update to the 2019 IRP to allow consideration of items resulting from the 2019 acknowledgement process, provide a small window to pursue model replacement software, and start on its 2021 IRP. The 2021 IRP is scheduled to be filed by April 1, 2021, less than one year after a decision on the 2019 IRP is anticipated. The company therefore determined that it would not be meaningful or practical to also prepare an update to the 2019 IRP. Staff questions whether it would be more prudent to skip the 2019 IRP update, consistent with the company's November notice, but wait to file the 2021 IRP until October 2021 (two years after the filing of the 2019 IRP). Staff suggests this could provide additional time for the company and stakeholders to engage in the upcoming All-Source RFP process. While the company appreciates Staff's intent, there are requirements that exist in the company's other regulatory jurisdictions that necessitate filing no later than April 1, 2021.[113] Because the company's IRP is a multi-state effort, it would not be possible to delay the Oregon IRP until October 2021 while also meeting all of the company's other regulatory requirements.

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[113] For example, the Washington Utilities and Transportation Commission issued an order in December 2019 that directs the company to file its next IRP no later than April 1, 2021.

V. CONCLUSION

PacifiCorp's 2019 IRP complies with the Commission's standards and guidelines. The 2019 IRP includes robust portfolio modeling and prudent planning assumptions that led to selection of a least-cost, least-risk preferred portfolio. The 2019 IRP also includes an action plan that is consistent with the long-term public interest. PacifiCorp appreciates the comments received from an active and engaged stakeholder group and continues to support stakeholder participation throughout the IRP development process to foster constructive dialogue.

PacifiCorp requests that the Commission acknowledge the 2019 IRP and the 2019 IRP action plan.

Respectfully submitted this 5th day of February, 2020.

Etta Lockey
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PacifiCorp d/b/a Pacific Power