BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 70

In the Matter of PACIFICORP, dba PACIFIC POWER, 2019 Integrated Resource Plan.	Final Comments

1. EXECUTIVE SUMMARY

Staff's final comments begin with an Action Plan summary in Section 2 and recommendations regarding the 2019 Action Plan in Section 3. Following these recommendations, in Section 4, Staff presents its analysis and recommendations regarding the IRP methodology more generally, and provides more detail and support for Staff's recommendations on the Action plan.

Staff finds that PacifiCorp has achieved an IRP process and methodology with generally a high degree of transparency and analytical robustness. Staff's comments and recommendations are intended to suggest specific improvements to this IRP, and to facilitate further improvements in the transparency and accuracy of PacifiCorp's RFP and next IRP.

In Opening Comments, Staff identified seven major concerns and areas for further investigation with PacifiCorp's IRP:

- Transmission projects and their selection in the portfolio modeling process,
- Load and Resource Balance Table accuracy,
- Risks of acquisition in advance of need,
- Lack of detail in the Request For Proposals (RFP) action item,
- Consistency of energy efficiency modeling between states,
- Lack of near-term demand response resources, and
- Potential regional resource adequacy deficits.

Staff appreciates PacifiCorp's responses to all stakeholders in its February 5, 2020, Reply Comments. Staff found that the Company's Reply Comments were helpful in furthering the dialogue with stakeholders and providing crucial information on energy efficiency, coal plant assumptions, and the RFP process. However, Staff still has concerns in a few areas:

- Transmission projects and their selection in the portfolio modeling process,
- Load and Resource Balance Table accuracy,
- Addition of 500 MW of reliability resources,
- Cost and risk of acquiring resources (including transmission) in advance of need, and
- Lack of detail in the RFP action item.

Finally, PacifiCorp filed the all-source request for proposal (RFP) referenced in this IRP's Action Plan on February 24, 2020. These comments will share Staff's initial reactions to the Company's RFP application. Staff has broad concerns not only about PacifiCorp's preferred approach of concurrent IRP and RFP filings without review of the RFP elements in the IRP or IE selection docket before a draft is filed, but also regarding such issues as:

- A potentially unbounded upper limit of acquisitions;
- Consideration of long lead-time resources under a waiver process;
- Resource acquisition timing relative to capacity need;
- A rushed review process, like the last RFP, especially in light of the new competitive bidding rules and PacifiCorp's queue reform filing at FERC.

2. ACTION PLAN SUMMARY

Below is a summary of the 2019 IRP action plan, along with any modifications that PacifiCorp has agreed to make:

Category	2019 Action Plan Item Summaries	PacifiCorp Modifications
Existing Resources	1a – Naughton Unit 3 conversion by 2020.	
	1b – Cholla Unit 4 retirement by 2023, earlier if possible.	
	1c – Jim Bridger Unit 1 retirement by end of 2023.	
	1d – Naughton 1-2 retirement by end of 2025.	
	1e – Craig Unit 1 retirement by end of 2025.	
New Resources	2a – RFP to secure resources for customer preference (voluntary green) programs.	
	2b – Issue an all-source RFP by end of 2023.	
Transmission	3a – Energy Gateway South (EGS) built by end of 2023.	
	3b – Utah Valley reinforcements as necessary to facilitate customer-preference resource interconnection.	
	3c – Northern Utah reinforcements • Rebuild two miles of Morton Court 138 kV line • Loop Populus-Terminal 345 kV line into Bridgerland and Ben Lomond, build 345 kV yard and ancillary circuit breakers. • Complete plan of service in time to support resource acquisitions from 2019 IRP in region.	
	3d – Utah South reinforcements • Complete rebuild of Mona- Clover lines #1 and #2. • Identify route and terminals for 70-mile 345 kV line. • Develop plan of service to support new resources in southern Utah.	
	3e – Yakima WA reinforcements • Facilitate interconnection of preferred portfolio resources with upgrades to local substations • Complete Vantage-Pomona Heights 230 kV line. • Establish type and location of new resources.	
	3f – Continue to support Boardman-to-Hemingway (B2H) process.	
	3g – Energy Gateway West • Segment D.2 completed by end of 2020. • Continue permitting and funding plans for Segments D.3 and E.	

Category	2019 Action Plan Item Summaries	PacifiCorp Modifications
Demand Side Management (DSM)	4a – Acquire all cost-effective Class 2 DSM, per Appendix D, Volume II, and Class 1 DSM in Utah.	
Front Office Transaction	5a – Acquire short-term firm market purchases and balance trading through competitive exchange and bilateral transactions when prompted.	
Renewable Energy Credit Actions	6a – Secure unbundled Renewable Energy Credits (RECs) for compliance.	
	6b – Maximize the sale of RECs.	Revise language to reflect that only RECs from states without RPS obligations will be sold.

3. STAFF'S RECOMMENDATIONS REGARDING THE 2019 ACTION PLAN

3.1. TRANSMISSION

3.1.1. ENERGY GATEWAY SOUTH (EGS)

Staff has serious concerns about the inclusion of Action Item 3a to construct Energy Gateway South (EGS), a 400-mile transmission line tying Aeolus, Wyoming to the Mona market in Utah, in the 2019 Action Plan.

Staff does not recommend acknowledgement of the EGS action item in part because, as Staff, Sierra Club, and the Alliance of Western Energy Consumers (AWEC) argued in Initial Comments, any acknowledgement of the construction of EGS should be contingent on RFP modeling actually selecting EGS, but the Action Plan requests acknowledgement of EGS outright. Acknowledgement of the current action item would create ambiguity as to whether the Commission had acknowledged EGS outright, or whether acknowledgement was contingent on its selection in an RFP.

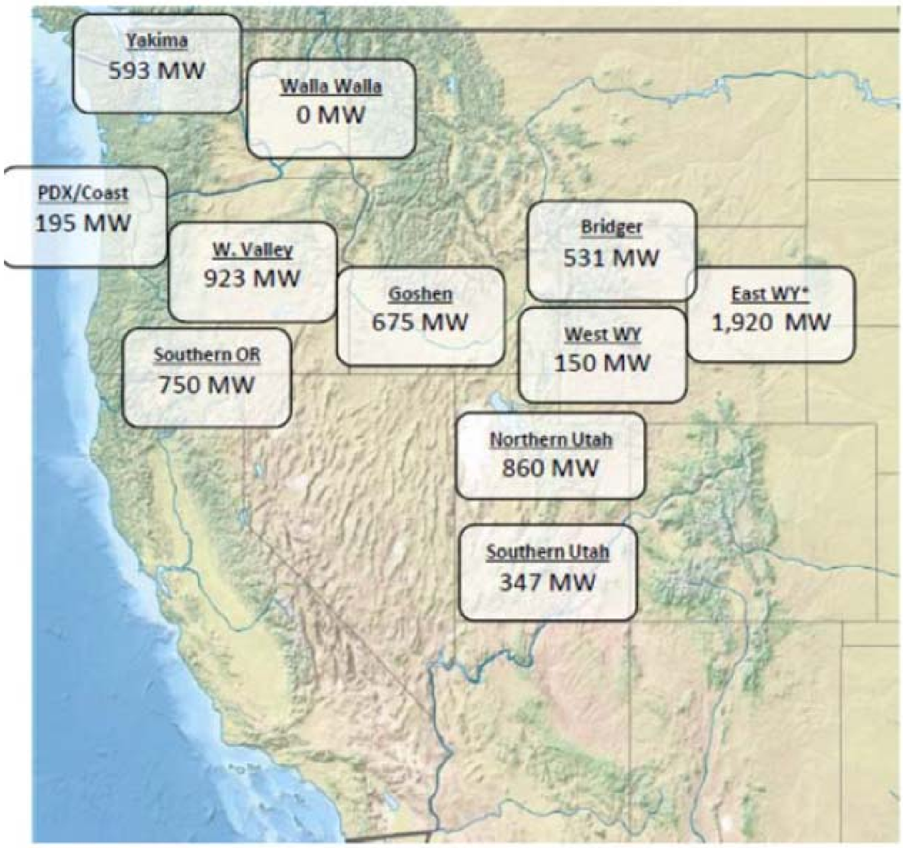
Additionally, Staff questions whether EGS is truly a least-cost, least-risk resource for ratepayers in the action plan timeframe. Staff has performed analysis showing that delaying EGS until 2030, which is the next year of significant wind investment in the preferred portfolio, would save ratepayers approximately $355 million in Net Present Value Revenue Requirement (NPVRR) through deferral of depreciation, interest, and taxes. Every year that EGS can be delayed will increase the savings to ratepayers substantially, and even in 2030, it appears that PacifiCorp may have enough interconnection capability to connect about 1,000 MW of new generation without building EGS. [1]

As explained by PacifiCorp in its February 13, 2020, update to the Oregon Public Utility Commission (Commission or OPUC), PacifiCorp believes it is possible to bring over 2,000 MW of locationally-diverse wind generation to customers in 2024 with a 60 percent Production Tax Credit (PTC), in addition to the 2,000 MW of wind near Aeolus, WY that relies on EGS to interconnect.[2]

[1] PacifiCorp – Oregon IE RFP—Attachment C-1. Page 1.
[2] PacifiCorp's presentation for the February 13, 2020 Commissioner Workshop in LC 70.

In the Company's IE RFP filing of February 24, 2020, PacifiCorp shows that the assumed interconnection limit for new resources across its system is about 3,350 MW in total:[3]

Locational Initial Shortlist Capacity Limits
(1.5x Pref. Port. or 1.5x Assumed Interconnection Limit)



*Note, eastern Wyoming includes Aeolus and NE Wyoming, which combined, will be limited to 1,920 MW. [4, 5]

PacifiCorp's capacity expansion model, System Optimizer (SO) has selected EGS in 2024. However, Staff struggles to make intuitive sense of why System Optimizer would choose to build EGS to support Wyoming wind acquisition (with a 40 - 60 percent PTC) in 2024, at a cost of $1.8 billion, when it could connect a similar amount of locationally-diverse wind (also with a 40-60 percent PTC) in 2024, and defer the $1.8 billion cost until EGS is truly needed.[6]

There are three main sources of benefits that the Company expects from EGS:

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[3] 3,350 MW calculated based on data in in this map, as 150 percent of assumed interconnection limit.

[4] PacifiCorp – Oregon IE RFP—Attachment C-1. Page 1.

[5] This map represents 150 percent of the interconnection capacity assumed available at each location.

[6] PacifiCorp 2019 IRP, Table 8.16, Page 247.

1) The high capacity factor and favorable seasonal wind shape of Wyoming wind that relies on EGS to interconnect,
2) The PTC value associated with Wyoming wind, and
3) Improvements to the reliability of PacifiCorp's transmission system associated with EGS. [7,8]

PacifiCorp needs to do more than report the findings of its model as a black-box answer. PacifiCorp must now be able to clearly demonstrate to the Commission how the favorable wind profile and transmission reliability benefits associated with EGS and Wyoming wind in 2024 will create enough value, as compared to a portfolio of a similar amount of locationally-diverse wind in 2024, to offset the $355 million in ratepayer cost associated with constructing EGS in 2024 instead of 2030. This amount would increase with each year that EGS could be delayed after 2030.

Interconnection Contracts near Aeolus, WY

Staff also questions why PacifiCorp Transmission has already signed interconnection contracts with developers near Aeolus based on Facilities Studies performed by PacifiCorp that 1) assume EGS will be constructed by 2024, and 2) do not require that interconnection customers pay for the construction of EGS even though they rely on it to interconnect.[9] Staff questions why PacifiCorp has signed contracts that depend on EGS being paid for by anyone other than the interconnection requesters, when interconnection customers should be required to pay for the upgrades needed to interconnect. Why is PacifiCorp's transmission side assuming that PacifiCorp will build EGS for its retail customers in 2024, even though EGS construction in 2024 has not been included in an IRP preferred portfolio prior to the 2019 IRP?

If PacifiCorp is required by federal law to build EGS for its interconnection customers, then the Company should engage the OPUC in a conversation about that requirement and present several options regarding how that requirement could be funded, including options where utility customers and interconnection customers share the cost of the investment, options where a third party owns the transmission, and options where the line is delayed until 2030 or later. The presentation should include an estimate of NPVRR and rate impacts for each option.

Right-of-way grant for EGS

PacifiCorp has explained that it has doubts regarding whether it can renew its right-of-way grant for EGS with the United States (U.S.) Bureau of Land Management (BLM). In response to Staff discovery, the company reported no knowledge of a BLM permit renewal application that had ever been denied by BLM, and no information indicating BLM would be likely to make substantial changes or deny renewal of the EGS construction permit.[10,11] When Staff asked PacifiCorp about its reasons for doubting whether its permit could be renewed, the reply said:

[7] PacifiCorp's response to Staff DR 70.
[8] PacifiCorp 2019 IRP. Page 75.
[9] See the Draft Facilities Study Report for Interconnection Customer Q0409 https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Q409FS.pdf.
[10] PacifiCorp's response to Staff DR 211.
[11] PacifiCorp's response to Staff DR 210.

> The primary risk is the passage of time. This passage of time could result in a determination by the future United States (U.S.) Bureau of Land Management (BLM) authorized officer, in a future administration, that the data used in the original Environmental Impact Statement is stale and that a new analysis will be required. This new analysis could lead to the project not being authorized or changed to such a degree that it no longer meets PacifiCorp's purpose and need. As discussed in the company's response to OPUC Data Request 207, PacifiCorp's experience is that this could take as much as eight to 12 years.[12]

Staff questions why this risk is any higher for EGS than for any of the other potential future lines, to a degree that would justify requiring the IRP model to select EGS before 2028, as PacifiCorp has done in this IRP.[13]

EGS also received a construction-cost-estimate reduction prior to the filing of the IRP, and to Staff's knowledge a similar cost reduction was not provided for any other transmission resource. PacifiCorp reported in response to a Staff discovery request that the cost reduction was due to the discovery that a lower-cost guyed-V tower could be used to save substantial costs on EGS.[14] The Company appears not to have applied any similar cost savings to other lines. Is there a reason that EGS was able to utilize these towers while other transmission lines are not?

In conclusion, Staff can not recommend acknowledgement of EGS unless the Company can demonstrate how Wyoming wind connected to EGS will provide customers with at least $355 million more value than the construction of an equivalent amount of wind resources by 2024 that do not require EGS.

<u>Recommendation(s):</u>

The Company should provide a detailed, quantitative assessment in final comments detailing why its portfolios are justified in bringing EGS online in 2024 to facilitate PTC wind when there appear to be an abundance of locations for new wind that would not require building EGS. PacifiCorp should include answers to the following questions:

- **What factors does PacifiCorp find justify building EGS when other locations are seemingly available for wind without such a large transmission upgrade?**
- **What resources would System Optimizer have chosen if EGS were not available until 2030, and why does the model expect those resources to add more than $355 million in present value revenue requirement (NPVRR)?**

Before an acknowledgement decision on Energy Gateway South, PacifiCorp should reply in written comments regarding any legal requirement for it to build EGS, as well as the possibility of a variety of funding options for EGS, including ratepayer and interconnection customer funded options, cost-sharing between ratepayers and interconnection customers, and third party transmission ownership. The Company should develop a report on the NPVRR and rate impacts to utility ratepayers of each proposal.

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[12] PacifiCorp's response to Staff DR 206.
[13] PacifiCorp's Response to Staff DR 132.
[14] PacifiCorp Response to Staff DR 154.

PacifiCorp should report in Final Comments on the possibility and costs of renewing the EGS BLM permit in 2022 so that it will continue to be relevant and, regardless, include fresh data for a delay in construction until 2030.

Staff requests that PacifiCorp reply in final comments on the possibility of identifying savings at other Energy Gateway projects such as B2H and Segment E through the use of lower-cost guyed-V towers.

Acknowledgement of any future RFP shortlist that includes EGS should consider including a condition on PacifiCorp's satisfactory demonstration of what specific benefits EGS provides that outweigh the $355 million cost of construction in 2024 versus 2030.

3.1.2. THE COMPANY HAS YET TO PROVIDE A CLEAR OUTLINE OF TOTAL COSTS OF TRANSMISSION ACTION ITEMS

In Opening Comments, Staff indicated it would investigate the costs of all Energy Gateway segments. Staff requested this information and received it in a confidential spreadsheet, but there was incomplete information on future segments, and because some of the investments were made years ago, it was unclear whether all the numbers on the spreadsheet were in nominal or real dollars.

Staff reviewed the IRP, IRP appendices, and submitted discovery multiple times in order to determine total costs of requested transmission Action Items and Energy Gateway. When Staff plainly asked the Company to provide an estimate of all the items in the Action Plan, PacifiCorp referred Staff to Table 1.1 in the IRP.[15] However, the items in Table 1.1 do not clearly match up to the items in the Action Plan or the Transmission Options in Table 8.6. The costs are scattered and labeled according to the transmission bubbles in System Optimizer and do not explicitly align with the bullets in the Action Plan. **PacifiCorp must provide a clear outline of total transmission investment cost in the Action Plan in its Final Comments.** It is unacceptable that the Company has failed to provide a clear outline of these total costs for what it is requesting the Commission to acknowledge. The Company should also provide a **clear** demarcation of total costs of each transmission bullet in the Action Plan and how it aligns with the preferred portfolio so that stakeholders can get a clear estimate of total costs.

Recommendation(s):

PacifiCorp must provide a clear outline of total transmission investment cost in the Action Plan in its Final Comments. The list should also indicate how it aligns with the preferred portfolio and include information on whether each transmission Action Item (including upgrades) is contingent on resource selection in the preferred portfolio and/or RFP.

3.1.3. SUBSTANTIALLY COMPLETE ACTION ITEMS ARE INAPPROPRIATE FOR AN ACTION PLAN

Many of PacifiCorp's requested Action Items are substantially complete, or will be substantially complete by the time the Commission makes a decision on acknowledgement in May 2020. In addition,

[15] See PacifiCorp Response to Data Request 154.

some of the Action Items in the Action Plan have already been acknowledged.[16] In the future, the Company should not be using the Action Plan as an update to current Action Items or requesting acknowledgment for projects that are substantially complete.[17]

Recommendation(s):

In the future, the Company should not use the Action Plan as an update to current Action Items or request acknowledgment for projects that are substantially complete.

3.1.4. THE COMPANY SHOULD ADDRESS SEGMENT D.1 IN FINAL COMMENTS.

In Reply Comments, the Company states, "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."[18] Staff would like to point out that construction of Segment D.1 appears to be a very real possible outcome of the 2020AS RFP. The Company should address the likelihood of segment D.1, Windstar to Aeolus, buildout in Final Comments, and address why it was not included in the Action Plan (contingent on selection in a near-term RFP) if wind additions could trigger this investment.

Recommendation(s):

The Company should address the probability of Segment D.1 being chosen in a 2020 RFP, including the additional costs associated with this segment.

3.2. CLASS 1 DEMAND SIDE MANAGEMENT (DSM), DEMAND RESPONSE

In Initial Comments, Northwest Energy Coalition (NWEC) proposed that PacifiCorp hold a Demand Response RFP "so as to fully test the market for readiness, pricing and range of program offerings, as well as a detailed assessment of potential Company-managed program options to acquire these resources and complement third-party providers of demand flexibility."[19] PacifiCorp expressed openness to a Demand Response RFP in its Reply Comments.

Staff supports PacifiCorp's proposal to meet with interested stakeholders to discuss the scope and scale of a demand response RFP, and encourages a timeline that would allow such an RFP to inform the demand response cost and operational assumptions in the next IRP.

In section 4.2.2, Staff's final comments include an in-depth discussion of demand response in the 2019 IRP. Staff explains that PacifiCorp needs to engage stakeholders in near term processes toward the acquisition of all cost-effective demand response.

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[16] The Commission already acknowledged Segment D.2 in the 2017 IRP, but this Action Item has been repeated in the 2019 IRP.

[17] See Order No. 14-252.

[18] PacifiCorp Reply Comments, page 37.

[19] NWEC Opening Comments. Page 8.

Recommendation(s):

Staff recommends PacifiCorp update its DSM action item to reflect the development of a proposal for a DSM pilot program in Oregon to be filed with the Commission, and a stakeholder process to discuss a potential future demand response RFP.

3.3. ALL-SOURCE REQUEST FOR PROPOSALS (RFP)

The RFP rules indicate that an RFP must use the same methodology as the most recent IRP, unless a separate filing is made in the Independent Evaluator (IE) docket.[20] The preferred portfolio derived through the IRP methodology includes approximately 4,000 MW of renewable resources, and 600 MW of storage in 2023. In a filing on February 13, 2020, PacifiCorp reported that an additional 2,130 MW of resources would be added to the preferred portfolio in 2025 as a result of the PTC extension. However, PacifiCorp filed its application to open an Independent Evaluator selection docket on February 24, 2020, and in its application proposes a solicitation of up to 4,400 MW of new generating resources and 600 MW storage resources targeting a commercial operation date on or before December 31, 2024.[21] The 2,130 additional resources by 2025 do not appear to be included in the RFP application.

Staff has several concerns about the RFP, described in the sections below:

3.3.1. SPECIFICITY OF RFP ACTION ITEM

Staff finds acknowledgement of an RFP action item without limitations on the size or cost of new resources to be problematic. Without a limit on capacity or cost, an RFP could potentially identify a new opportunity resulting in the model choosing thousands more MW than the IRP preferred portfolio. While the modeling in the IRP may be reasonable, there are more considerations than just NPVRR when looking at a portfolio including substantial new resource additions. These risks should be discussed in a transparent IRP process, not during an RFP that could turn out to be substantially different from the most recent IRP preferred portfolio. Staff notes that in PacifiCorp's IE application in Docket No. UM 2059, PacifiCorp has proposed an RFP for up to 4,400 MW of new generation and 600 MW of energy storage. However, Staff's position is that it would be helpful for the Company to update its Action Item to also include an upper limit on generation and storage capacity.

Recommendation(s):

PacifiCorp should amend its 2019 Action Plan to reflect a condition that the RFP will not exceed 110 percent of the cost or capacity of resources in the 2019 preferred portfolio action plan timeframe, as amended for the PTC extension.

3.3.2. LONG LEAD-TIME RESOURCES

As noted by the Northwest & Intermountain Power Producers Coalition (NIPPC) and *Swan Lake* in opening comments, the RFP proposed in PacifiCorp's 2019 IRP Action Plan does not allow for long-lead-time resources, because it requires resources to be online by the end of 2023. While Staff supports an RFP that allows participation by long-lead-time resources, Staff does not necessarily support giving long-

[20] OAR 860.89.0250

[21] PacifiCorp Application to open an Independent Evaluator selection docket. Page 1.

lead-time resources a waiver from the competitive bidding guidelines, a question on which Swan Lake has requested clarification from the Commission. Instead, Staff proposes that PacifiCorp should include long-lead-time resources in a separate RFP for flexible capacity resources, with special consideration for non-emitting flexible capacity resources including demand response and pumped hydro, given the risks associated with carbon emissions and climate change.

Recommendation(s):

Staff recommends a separate RFP for up to 200 MW of flexible capacity to come online after 2024 and before 2027. Given the risks associated with carbon emissions and climate change, Staff believes greater consideration should be given to non-emitting flexible capacity resources, including demand response and pumped hydro.

3.3.3. PROCUREMENT IN ADVANCE OF PACIFICORP'S CAPACITY DEFICIT

The RFP seeks to acquire generation resources about three years in advance of the capacity deficit shown in the Company's load resource balance for capacity. In reviewing PacifiCorp's 2019 IRP, Staff considers available FOTs to be included in the definition of system capacity, because they are assumed to be available to meet peak load in portfolio modeling.[22] Although PacifiCorp points out that it is dependent on market transactions for capacity almost immediately,[23] the Company has shown no analysis indicating uncertainty as to whether the 1,425 MW market capacity limit will be available in the near term. Thus, avoiding market purchases does not appear to represent a need in the near term.

PacifiCorp's load and resource balance analysis shows the first capacity deficit to occur in 2026 in the Eastern Balancing Authority Area (BAA), when the Company is short 839 MW in the summer after acquiring FOT market energy. The first system-wide capacity deficit of 839 MW in the summer occurs in 2028.

To some extent, PacifiCorp's load resource balance analysis may result in the appearance of a resource deficit year that is closer than PacifiCorp's true deficit year, because the Company uses low-end estimates of Qualifying Facilities (QF), and private generation forecasts in the load resource balance tables. Staff discusses the load resource balance accuracy in section 4.6.

Given that the planned 2023-2024 resource acquisition in the 2020AS RFP seeks to procure resources about 3-5 years in advance of a capacity deficit, and that this acquisition is based on a potential to create substantial ratepayer savings through PTC value, Staff finds that some amount of resource acquisition before 2024 could be a part of a reasonable least-cost, least-risk, long-term plan, although the risk to ratepayers of an unexpected change in market conditions will increase with the cost of the resources acquired in the near term. Economic risk and opportunity are discussed further in sections 4.1.1 and 4.1.2.

[22] PacifiCorp 2019 IRP. Page 170.

[23] PacifiCorp Reply Comments. Page 23.

3.3.4. TIMING OF RFP FILINGS

Oregon's RFP rules require that PacifiCorp file its proposed RFP scoring and methodology in the IE docket before filing a draft RFP. Staff appreciates PacifiCorp's filing of the RFP scoring and methodology details in its recent IE docket application in UM 2059. However, the 60-day time for review of the scoring and methodology before the draft RFP is filed is not consistent with Staff's understanding of the new RFP rules, as motivated by creating a transparent and thorough process for reviewing scoring and methodology comparable to that which would be available if the Company included those details in its IRP. The price and non-price scoring process in the RFP application appears to utilize a 'proprietary pricing model' not used in the IRP.[24] The process as outlined by PacifiCorp does not include enough opportunity for transparent and thorough analysis of the RFP scoring and methodology details. Creating a precedent of such a condensed timeline for review of the scoring process would not reflect the intent of the new competitive bidding rules. Staff plans to make the necessary filings in in Docket No. UM 2059 to further explain these concerns and propose remedies.

3.3.5. QUEUE REFORM

Staff appreciates PacifiCorp's explanation in its Reply Comments of how queue reform will be included in the planned RFP if approved by FERC by June 2020. Staff is hopeful that the cluster study and 'first ready, first served' attributes of queue reform will be available to help make any upcoming RFP more competitive.

3.3.6. CHANGE TO RFP ACTION ITEM

PacifiCorp has filed an application for a RFP docket with the Oregon Public Utility Commission. In the application, resources are asked to achieve commercial operation by 2024. This is a different timeline than the 2023 date in the 2019 IRP action item.

Recommendation(s):
PacifiCorp should update its action item to reflect the change from a 2023 to 2024 Commercial Operation Date (COD).

3.3.7. POTENTIAL IMPROVEMENTS TO THE RFP PROCESS

Staff is interested in learning more about Sierra Club's suggestion to better integrate the IRP and RFP processes for increased transparency, as demonstrated by NIPSCO and Colorado utilities. An IRP that utilized actual bid data could provide more transparency into the RFP process, as well as more accuracy in IRP modeling and results.

Recommendation(s):
PacifiCorp should report in Final Comments on whether real bid data could be used in its next IRP.

[24] PacifiCorp's Application for Approval of 2020 All-Source Request for Proposals. Attachment C, Page 4. Docket No. UM 2059.

3.4. CUSTOMER PREFERENCE RFP

Staff applauds the Company's collaboration with its customers and communities in response to increasing customer preference for renewable generation. Staff is continuing to follow the development of various customer preference options for PacifiCorp customers, and is interested in a conversation with the Company about how to ensure protections for non-participating customers while providing program options that meet customers' needs.

In order to ensure that customer preference resources remain separate from IRP resources, while providing transparency into the acquisition of customer preference resources, Staff proposes that PacifiCorp bring forward any customer preference agreements in a filing with the Commission, so that stakeholder review can verify that the procurement does not harm other ratepayers who are not participating in the program.

4. STAFF RECOMMENDATIONS REGARDING THE 2019 IRP METHODOLOGY AND ASSUMPTIONS

4.1. ECONOMIC RISK AND OPPORTUNITY

4.1.1. ECONOMIC RISK

When the Company acquires resources in advance of its forecast capacity deficit as predicted in the IRP load resource balance study, the potential risks to customers increase due to the increasing uncertainty as to whether future market and policy variables will stay within the range of expected values forecast in the IRP.

Staff finds that a thorough evaluation of the risks of early acquisition is warranted. While the Company's NPVRR metrics show that the preferred portfolio is expected to benefit customers, there are some risks not fully accounted for in IRP modeling:

PTC doesn't expire

- A renewal of the PTC would result in the 2024 acquisition of PTC wind turning out to be a sub-optimal resource choice as compared to a later acquisition of PTC wind.
- However, given the now-competitive economics of renewables the PTC may be less likely to return after 2024.

Market prices don't increase

- Given the recent trend of low market prices, low natural gas prices, and low-variable-cost renewable energy, a sustained low-market-price future seems possible, and is not among the futures considered in the 2019 IRP.
- Additionally, the Company's plan to install several GW of wind in the near-term may reduce market prices in the regions where resources are constructed due to the low-variable cost of renewable generation. PacifiCorp's IRP analysis may not fully account for these localized market effects, since the PacifiCorp market price forecast is based on an Aurora WECC

buildout that may not have included new renewable resources in the same locations that PacifiCorp's IRP includes new renewable resources (Aeolus, Wyoming, for example.)

Wind and solar costs decrease more rapidly than expected

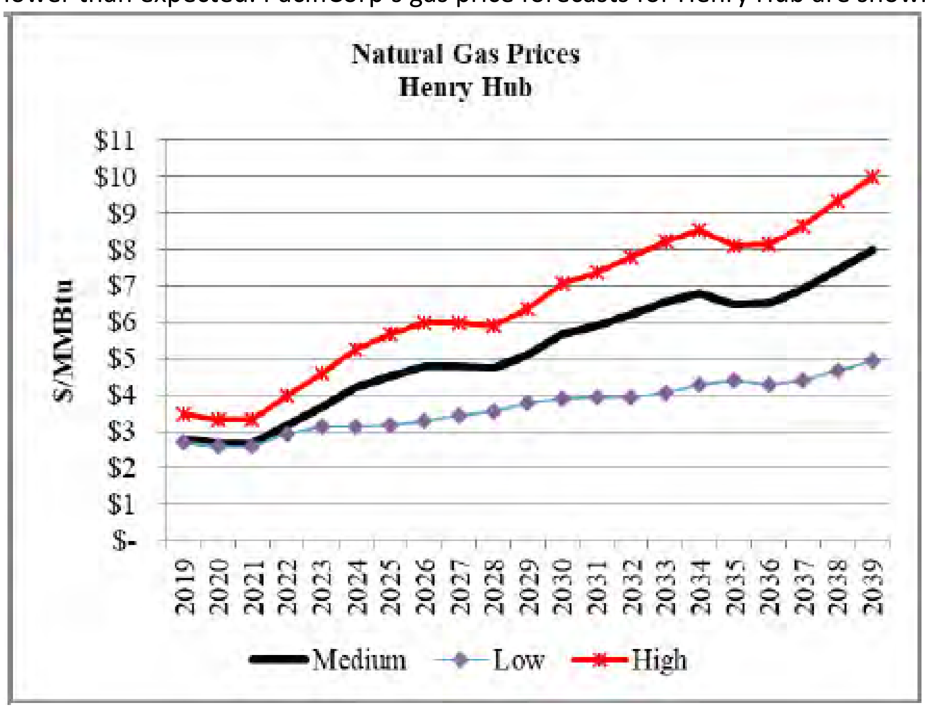
- If the cost of renewable resources decreases more rapidly than the cost curves considered in the 2019 IRP, then the near-term acquisition of resources could turn out to be less economic than a strategy of waiting until the future when costs would be significantly lower.

WY wind tax increases

- The Wyoming legislature has proposed several times an increase in the Wyoming wind tax from $1 per MWh to $5 per MWh.[25]

Gas prices don't increase as much as expected

- If gas prices increase less than expected, then the value of renewable resources will be lower than expected. PacifiCorp's gas price forecasts for Henry Hub are shown in this graph:



[26]

- For perspective, NW Natural's 2018 IRP forecasts gas prices at Opal, Sumas, and AECO will be about $4 in 2038.[27] PacifiCorp's IRP forecasts for Opal, Sumas, and AECO will average $6.40 in 2038, a 60 percent increase.[28]

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[25] S&P Global Market Intelligence. How Wyoming went from leader to laggard in wind energy. April 10, 2019.
[26] PacifiCorp 2019 IRP, Page 182.
[27] NW Natural 2018 IRP, Page 2.14.
[28] PacifiCorp 2019 IRP Public Data Disk. Medium Gas price curves.

4.1.2. ECONOMIC OPPORTUNITY

On the other side of the equation, economic and policy variables could stay within the range PacifiCorp forecasts, or turn out to be even more advantageous for customers than expected.

Factors that could result in PacifiCorp's Action Plan acquisitions turning out as expected or better include:

- Market prices increase more than expected,
- A carbon price is higher than expected,
- Wind and solar costs don't decrease as much as expected,
- The WY wind tax goes away, or
- Gas prices increase more than expected.

In summary, the uncertainty involved in long-term planning is substantial. While there is some possibility that the unexpected could occur in ways that make PacifiCorp's early acquisition even more beneficial than any scenario considered in the IRP, the opposite is also possible. Staff finds while pursuing cost reductions through early acquisition can result in positive outcomes for ratepayers, protecting ratepayers from the risks of unexpected events is essential when considering such a strategy.

Staff's recommendations for protecting ratepayers from the increased risks of an early acquisition strategy include:

1. The full value of PTCs projected in the IRP should be provided to ratepayers.
2. If PacifiCorp Company conducts an RFP under the Competitive Bidding Rules, the Company should provide an updated economic analysis with the request for acknowledgement of the final shortlist from the 2020AS RFP.
3. The risk of proceeding with the resource acquisition remains with PacifiCorp unless and until the Commission completes a prudence review and approves cost recovery of these resources in rates. Recovery may be conditioned or limited to ensure customer benefits remain at least as favorable as IRP planning assumptions.

4.2. ENERGY EFFICIENCY AND DEMAND SIDE RESOURCES

4.2.1. ENERGY EFFICIENCY

In Initial Comments, Staff proposed that energy efficiency acquired in Oregon may be subsidizing other parts of the system. This is a concern for Staff, because if there is a need to make resource acquisitions or an opportunity to hasten the retirement of non-economic resources, then the best resource for Oregon ratepayers is the least cost, least risk resource— all cost-effective energy efficiency. Cost-effective energy efficiency is the first choice for resources whether they are in Oregon, or from another state in the system. Given Oregon's longstanding history of achievement in energy efficiency as evidenced by a consistent ranking in the top ten on American Council of Energy-Efficient Economy's (ACEEE) annual Energy Efficiency Scorecard,[29] Staff expects that more energy efficiency can be attained in some parts of the system at even lower cost than in Oregon. Oregon ratepayers should experience the system-wide benefit of acquiring more cost-effective EE in other states before other resource

[29] ACEEE's State Energy Efficiency Scorecard https://www.aceee.org/state-policy/scorecard.

acquisitions are considered. To this end, Staff directed its analysis towards opportunities to improve energy efficiency selection.

In opening comments, Staff suggested that the learnings from the Oregon Energy Efficiency Analysis Report could be applied to other states to improve energy efficiency forecasting. In reply comments, The Company stated that:

> As noted by Staff, the company has been working with the ETO [Energy Trust of Oregon] to improve energy efficiency selection; 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 and PacifiCorp continues to coordinate with ETO to ensure alignment in methodologies, where applicable and appropriate. Staff suggested that learnings from the study from the LC 67 modification could be applied to other states.[30]

Staff wishes to clarify that the attempt to align forecasts between Energy Trust and the Company is complete and the organizations have implemented what modifications they could agree upon. Staff reiterates the point that there may be learnings from this activity that could point to possible improvements that may be applied to other states. However, the forecasted levels of EE in other states does not yet appear to reflect these potential improvements.

Notably, Energy Trust continues to find more cost-effective savings despite its past accomplishments. Ultimately, Energy Trust is entrusted in acquiring all cost-effective energy efficiency regardless of what may be planned for. The methods used by Energy Trust – beyond the region's 10 percent adder – to more accurately identify potential for energy efficiency must be applied to the rest of the Company's service territory so that these cost-effective sources of energy can be acquired. To this end, Staff supports NWEC's suggestion for PacifiCorp to consider a system-wide EE strategy *if* it is based on Oregon's successful approach to identifying and securing Class 2 DSM. Such a holistic approach could greatly benefit all PacifiCorp ratepayers, especially in light of the coming turnover in resources via the coal retirements and the proposed level of acquisition proposed in the 2020 RFP.

<u>Alternative Bundling Strategies</u>

In opening comments, Staff supported the Company's plans to study alternative strategies to "bundle" energy efficiency measures. In reply comments, the Company asserts that it is developing new approaches and will engage stakeholders in the development of these alternative bundling strategies.[31] Staff wishes to re-assert the need to identify a better approach for making energy efficiency selections.

When bundling by cost, energy efficiency measures with dissimilar temporal patterns are clumped together and the overall impact of these resources is muted for the purposes of resource selection. Staff finds that this dilution is further exacerbated when bundles are assigned a "planning capacity factor" (PCF). Energy efficiency bundles are graded based on this calculation, while not being optimized to meet capacity needs. This contributes to the under-selection of cost-effective energy efficiency by not maximizing bundling for desired benefits.

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[30] PAC reply comments p. 20-21.
[31] PacifiCorp Reply Comments. Page 20.

Recommendation(s):
For the next IRP, PacifiCorp should hire a third party to review the results of Oregon Energy Efficiency Analysis Report, recommending what practices can be adopted in other states and how PacifiCorp could develop a system-wide EE strategy that mirrors the success in Oregon.

PacifiCorp should pursue alternative bundling strategies, starting with optimizing bundles based on each major factor that will be evaluated when making resource selections in the 2021 IRP (E.g. energy value, capacity, peak capacity factor, etc.). Review results with stakeholders and identify the appropriate combination of strategies to optimize "bundles".

4.2.2. DEMAND RESPONSE

Staff's Initial Comments
In Initial Comments, Staff notes concern about PacifiCorp's 2019 IRP preferred portfolio including substantial deployment of batteries despite apparently lower demand response product costs identified by the Company. Staff requests engagement with PacifiCorp in continuation of the discussion of demand response pilots that was initiated in response to Order No. 16-071. Staff notes a variety of issues (regional resource adequacy concerns, demand response as a least-cost resource for peaking capacity, PacifiCorp's success in achieving demand reduction in other states, and Oregon's statutory demand response language) which, when combined with the apparent cost differences of demand response and proposed battery storage, cause Staff to question the Company's good faith planning and pursuit of cost effective demand response in Oregon.

Staff concludes they could not recommend acknowledging PacifiCorp's DSM proposals unless 1) the Company better explains, and provides the data detailing, the calculations for evaluating cost-effective demand response opportunities in Oregon, and 2) the Company engages in an intensified effort to explore achieving greater demand response savings.

Staff makes three recommendations:

1. PacifiCorp should determine the amount of cost-effective demand response currently possible in its Western Balancing Authority Area (BAA), and seek to acquire that amount as part of the 2019 IRP action plan.

2. Before Staff's final comments, PacifiCorp should engage Staff and interested stakeholders in discussion of additional demand response pilots, such as a program tailored to commercial and industrial customers, a residential HVAC direct load control program, a domestic hot water heater direct load control program, etc.

3. Staff strongly suggests PacifiCorp work with Staff and Stakeholders to hire an independent third party to review PacifiCorp's methodology for demand response cost-effectiveness as presented in the IRP and Conservation Potential Assessment for 2019-2038 (CPA).

Stakeholders' Initial Comments

In Initial Comments, Citizens' Utility Board (CUB) notes with surprise the lack of demand response resources planned for Oregon in the near term, and notes the importance of this resource, and DSM resources broadly, in the Northwest Power Council's Seventh Power Plan. CUB points out that customer resources cannot be acquired overnight, and the Company does not seem to be planning actively towards achieving more of these resources, despite the fact that AMI deployment in Oregon will increase opportunities for demand response potential. CUB recommends that the Commission does not acknowledge Action Item 4a, Energy Efficiency Targets. CUB believes the Company has not fully explored energy savings opportunities while developing its preferred portfolio and needs to bring in more demand response resources in its system and in Oregon.

NWEC's Initial Comments note that regarding DSM resources broadly there is a lack of detail in the IRP regarding the preferred portfolio selection, and specifically the discussion and explanation of DSM resource analysis; this makes it impossible to recommend acknowledgement of DSM action items. NWEC is generally critical of the approach to demand response and Class 3 DSM. NWEC believes that the Company's CPA, as well as other PacifiCorp analytical work, provides a useful starting point for assessing demand response and Class 3 DSM, but that an overhaul is in order. They propose a new Action Plan item for the next IRP cycle which includes a new outside expert study, and a full stakeholder workshop. NWEC also proposes that the Company and the Commission consider a separate RFP for demand response resources to test the market for readiness, pricing and range of program option offerings.

PacifiCorp's Reply Comments

PacifiCorp's Reply Comments respond to Staff's second recommendation noting 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. Indeed, PacifiCorp held a conference call with Staff on January 30 regarding demand response pilots (amongst other related topics), and subsequently scheduled a workshop with Staff and stakeholders for April 14 to discuss demand response pilots (in addition to related topics).

With respect to Staff's third recommendation, PacifiCorp agrees there is value in stakeholder discussions to identify potential improvements to the CPA demand response methodology, including how the resources are evaluated with the IRP model. However, the Company sees limited value in utilizing a third party to review this methodology due to the development timing of the CPA for the 2021 IRP. The Company proposes to work with stakeholders to consider and address feedback through the CPA workshops for the 2021 IRP. PacifiCorp has started that process earlier in the IRP development to allow for more meaningful engagement and participation.

PacifiCorp next addresses Staff's concern about the Company's good faith pursuit of cost effective demand response in Oregon. The Company confirms there is no demand response proposed for Oregon in the Action Plan timeframe, and also confirms that the appropriate amount of economic demand response resources was selected over the 20 year planning horizon.[32] PacifiCorp expands:

> Demand response resources are represented in the SO [System Optimizer] 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.*

[32] PacifiCorp Reply Comments, page 17.

> [Emphasis added]. 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* [emphasis added].

PacifiCorp states that questions surrounding the valuation of demand response should not hold up acknowledgement of DSM action items given the thorough and time-tested analyses and evaluation involved. The Company notes improvements to DR modeling for the 2019 IRP, and that improvements to modeling DSM broadly for the 2021 IRP are under development.

PacifiCorp is open to discussing NWEC's proposed separate RFP for demand response resources, and suggests a meeting with stakeholders will be scheduled to discuss scope and scale. Staff notes that this item is on the agenda of the previously mentioned April 14 workshop.

PacifiCorp concludes demand response Reply Comments by noting opportunities and meetings (both future and past) held in development of the 2021 IRP and CPA, as well as the Company's openness to having additional meetings about CPA DSM methodologies and assumptions.

Staff's Final Comments

Staff appreciates PacifiCorp's timely follow up on Staff's second recommendation (engage Staff and stakeholders in discussion of additional demand response pilots) and looks forward to the potential outcomes this dialogue may lead to.

With respect to Staff's third recommendation (hire an independent third party to review PacifiCorp's methodology for demand response cost-effectiveness as presented in the IRP and CPA), Staff appreciates PacifiCorp's willingness to discuss CPA methodologies, as well as lead times necessary to complete preparatory work for the next IRP cycle. In 2020, Staff has participated in several of the 2021 CPA development and public input meetings PacifiCorp noted in Reply Comments. Staff notes that PacifiCorp shared initial plans in said meetings to adapt and adjust DSM (including demand response) modeling approaches, assumptions (for example, potential incentive levels) and costs. Staff is grateful too, for the Company's openness to having additional meetings about CPA DSM methodologies and assumptions, should they be necessary. In sum, Staff hopes these meetings, and methodological changes, yield greater stakeholder understanding of the Company's CPA process, as well as more transparent modeling inputs, processes, and results. Should the outcome fall short of this, Staff believes there is no other choice than to recommend entirely re-booting this aspect of the IRP planning process.

Staff recommended PacifiCorp should determine the amount of cost-effective demand response currently possible in its Western BAA, and seek to acquire that amount as part of the 2019 IRP action plan. It is PacifiCorp's response to this recommendation - that the appropriate amount of economic demand response resources was selected - that is disappointing to Staff.

For discussion purposes, Staff is willing to set aside the amount of demand response proposed in Oregon, in order to explore the Company's broader point that planning efforts are resulting in the appropriate amount of demand response being selected in the IRP planning horizon. In doing so, Staff again examines the 2019 IRP preferred portfolio inclusion of nearly 600 MW of battery storage deployed by the end of 2023 (these storage resources are paired with new solar generation) and nearly 1,400 MW of stand-alone storage resources deployed starting in 2028.[33] Staff next recognizes Action Item 4a: PacifiCorp will acquire cost-effective Class 1 DSM in Utah targeting approximately 29 MW of incremental capacity from 2020 through 2023.[34] By 2029, the preferred portfolio increases this amount to nearly 170 MW.[35]

Staff asserts that an effective demand response program meets a similar need as batteries: addressing a peak in demand. (Staff notes that each alternative provides unique benefits in addition to addressing peak.) In an effort to compare costs of these battery options to demand response on as near to an apples to apples basis as possible, Staff turned to 2019 IRP Table 6.2 (page 137) and calculated total fixed costs of the proposed storage systems to be paired with solar of $28.40 - 30.41/kW-Yr.[36] Staff again turns to 2019 IRP Table 6.2 (page 137) for cost information on stand-alone storage resources and finds that Li-Ion 15MW X 60 MWH total fixed system cost is $207.93/kW-Yr. Staff notes 2019 IRP Tables 6.6 and 6.7 (page 162) which present demand response products in the East and West Control Areas. These tables include four programs with levelized costs below $28/kW-yr [37] and five programs with lower bound levelized costs under $31/kW-Yr.[38] The results of this comparison are presented in the table below:

Demand Response Products & Supply-Side Resources (highlighted grey)	Levelized Cost ($/kW-yr)
Ancillary Services – Summer, East	($3) - $2
DLC Space Heating Res & C&I – Winter, West	$7 - $27
DLC Space Heating Res & C&I – Winter, East	$9 - $18
Ancillary Services – Summer, West	$14 - $20
DLC Cooling & WH - Res and C&I – Summer, East	($4) - $49
DLC Smart Thermostat – Res – Summer, East	$5 - $56
DLC Irrigation – Summer, East	$14 - $44
DLC Smart Thermostat – Res – Summer, West	$31 - $54
DLC Smart Thermostat - Res – Winter, West	$30 - $91
Proposed storage systems to be paired with solar (calculated as described in text)	$28.40 - 30.41 Total Fixed ($/kW-Yr)
Li-Ion 15 MW X 60 MWh	$207.93 Total Fixed ($/kW-Yr)

[33] PacifiCorp 2019 IRP. Pages 9, 29, 248.
[34] PacifiCorp 2019 IRP. Page 26.
[35] PacifiCorp 2019 IRP. Pages 11, 250, 258.
[36] Staff compared costs of solar-only systems to solar + storage systems to net out implied costs of the storage system components. For example: the following solar-only system has a total fixed cost of $120.46/kW-Yr (PV Milford, UT, 200 MW, 2021, 32.5% CF (30% ITC)). The analogous solar + storage system has a total fixed cost of $148.86/kW-Yr (PV + Stor, Milford, UT, 200 MW + 50 MW X 200 MWh (30% ITC)). The difference of the two is $28.40/kW-Yr. This exercise was done for each potential solar-only and solar + storage resource and yielded the range noted in text.
[37] 1) Ancillary Services – Summer, 2) DLC Space Heating Res & C&I – Winter in the West; 3) Ancillary Services – Summer, 4) DLC Space Heating Res & C&I - Winter in the East.
[38] 1) DLC Smart Thermostat – Res – Summer, 2) DLC Smart Thermostat – Res – Winter in the West; 3) DLC Cooling & WH - Res and C&I – Summer, 4) DLC Smart Thermostat – Res – Summer, 5) DLC Irrigation – Summer in the East

Staff again notes that demand response programs and battery resources each provide unique benefits in addition to addressing peak. The two are not entirely interchangeable in all circumstances, and Staff is willing to concede there may be benefits from battery resources that demand response programs simply cannot match. That being said, when faced with these modeling outcomes despite these cost comparisons, staff argues that PacifiCorp's efforts have not resulted in the appropriate amount of demand response. A least-cost and least-risk outcome would have included the pairing of solar with as much cost-effective demand response as was available – beyond 29 MW – and if necessary, then turn to pairing solar + batteries, by the end of 2023, and then as much cost-effective demand response as was warranted and available – beyond 170 MW – and if necessary, then turn to stand-alone batteries, starting in 2028.

Staff would also note that this table was presented in our initial comments and PacifiCorp did not reply. PacifiCorp's non-response to Staff's analysis of DR as a least-cost, least-risk capacity resource implies that the Company has not fully evaluated DR on a comparable basis to other resources, as required by the IRP guidelines. Thus Staff finds their Class 1 DSM action item problematic unless PAC poses a remedy in its final rounds of comments. Further, this omission in IRP analysis leaves staff to believe that a full analysis of Class 1 DSM in the IRP may result in not only a lower overall capacity need but also a lower capacity value for resources being pursued as economic opportunities in the RFP.

While Staff appreciates the difficulty of the IRP modeling exercise, Staff continues to wonder why the model has chosen such greater quantities of a more expensive resource. Staff welcomes any feedback from the Company on our points above, but absent any of that, Staff rejects the assertion that the appropriate amount of economic demand response resources was selected by the planning process.

<u>**Recommendation(s):**</u>

PacifiCorp should continue to engage Staff and interested stakeholders in discussion of additional demand response pilots.

PacifiCorp should continue to engage Staff and interested stakeholders in discussion and review of PacifiCorp's methodology for demand response cost-effectiveness as presented in the IRP and CPA with the goals of 1) continuing to make methodological improvements, 2) greater stakeholder understanding of the CPA process, and 3) more transparent modeling inputs, modeling processes, and modeling results.

Any PacifiCorp investment in battery deployment (stand alone or otherwise) should be disallowed until the Company can demonstrate it has identified, planned for, and implemented all technically achievable demand response that costs less than battery deployment, or proven that demand response is an invalid solution to the problem in question.

The Commission should direct PacifiCorp to include an appendix in its next IRP that clearly explains how the Company is planning to acquire all cost-effective Demand Response.

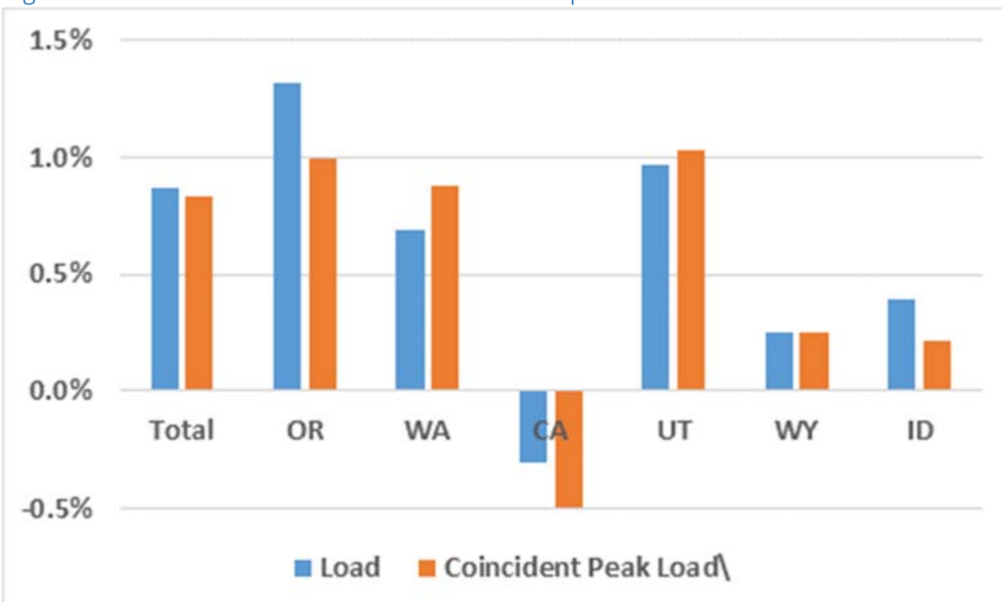
<u>**Demand Response Selection and Peak Load**</u>

In reply comments, the Company states that the difference in load forecasts is a main driver in differences in energy efficiency selection between states:

"Finally the load forecasts differ significantly between states and this is a significant driver for the different energy efficiency selections by state."[39]

If that is the case, Staff finds it curious that while the growth in coincident peak load has similar patterns from state to state, this did not result in more demand response selection in Oregon. The next figure and table compare the growth in load to the growth in coincident peak load by state. The trends in coincident peak loads by state are similar to the trends in load.

Figure 4.1 - Load and Coincident Peak Load Compound Annual Growth Rate 2019-2028



While this information does not refute the possibility that energy efficiency choices by state should be driven by expected load growth by state, it does point to some inconsistency in how demand-side resources are chosen at the state level, and further supports Staff's assertion that demand response is under-selected in Oregon.

4.3. REGIONAL RESOURCE ADEQUACY AND RELIABILITY

4.3.1. 500 MW CAPACITY IN EXCESS OF HOURLY SHORTFALLS

Staff appreciates Sierra Club's comments on the 500 MW of reserves added to portfolios to improve reliability. Sierra Club explains that PacifiCorp added 500 MW of 'reliability resources' in addition to any resources necessary to cover energy shortfalls identified in the Planning and Risk (PaR) reliability run. Sierra Club writes that the 500 MW of incremental resources above what is needed to serve load in PaR is "not needed and is redundant with capacity requirements incorporated during other stages of the Company's modeling."[40]

[39] PacifiCorp Reply Comments. Page 20.
[40] Sierra Club Opening Comments. Page 11.

In reply comments, PacifiCorp wrote that its 500 MW reliability resource addition was necessary to compensate for real-world uncertainty that was not captured in its hourly reliability modeling which, the Company states, 'lacks the stochastic variation required to serve as a complete proxy for real world conditions.'[41]

Staff find's PacifiCorp's explanation of why some additional reliability resources were needed to be completely justified and reasonable. However, the Company has not been able to provide a satisfactory answer as to why 500 MW of reliability resources is the right quantity, and the justification for this quantity looks even weaker after reviewing PacifiCorp's response to Staff discovery.

In the IRP, PacifiCorp justifies the 500 MW based on the amount of 'capacity held in reserve' during the summer of 2018:

> 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. [42]

However, in discovery, PacifiCorp wrote that 'capacity held in reserve' is defined as "the excess capacity on dispatchable generation that is available on the system after scheduling to serve PacifiCorp load."[43] Thus, there appears to be some question about whether the 500 MW represents a quantity of reserves deemed necessary by PacifiCorp operations for reliability, or is simply the amount of unused capacity that is left over on PacifiCorp's system after serving all system load.

Another area of uncertainty is whether a 'reliability shortfall' hour refers to an hour when there is actually Energy Not Served (ENS) on PacifiCorp's system, or whether a 'reliability shortfall' hour also refers to an hour when operational reserves are depleted, but no actual ENS occurs. In the latter case, it would be unnecessary to add a substantial buffer in addition to remedying the reliability shortfall, because remedying the shortfall would restore the appropriate level of operating reserves. An extra 500 MW would be unnecessary. In PacifiCorp's final comments, Staff requests the Company clarify whether reliability shortfalls are caused by ENS only, or are also caused by operating reserve shortages.

Staff is supportive of efforts to improve the methodology for identifying reliable portfolios in future IRPs. Utilizing the current IRP models, this could be accomplished through adjustments to System Optimizer that help the model to obtain a reliable portfolio on the first try, eliminating the need for a second System Optimizer run to add any new reliability resources. Portfolios with greater flexibility are likely to have fewer reliability shortfalls, and the current SO modeling methodology does not value flexibility, demand response, time-of-use rates, or storage highly enough, as shown by the reliability shortfalls in portfolios that should otherwise have enough energy to meet load, plus a thirteen percent reserve margin. One way this could be accomplished is by providing a credit to resources that provide a

[41] PacifiCorp Reply Comments. Page 11.
[42] PacifiCorp 2019 IRP. Appendix R. Page 610-611.
[43] PacifiCorp Reply to Staff DR 191.

high level of flexibility. Staff would be supportive of a conversation on how to improve the reliability of initial System Optimizer portfolios.

In addition, Staff supports PacifiCorp looking to the future by considering new IRP models that are better able to identify reliable portfolios on the first run. With less need for piecewise adjustments, which may somewhat decrease the efficiency and accuracy of the IRP portfolio cost optimization process, the IRP modeling process could be streamlined and least-cost portfolios could be identified more quickly.

Recommendation:

PacifiCorp should report in final comments on whether PaR 'reliability shortfalls' are the result of Energy Not Served, or of reserve deficiencies.

PacifiCorp should include and inform stakeholders in a process to improve the reliability of IRP portfolios.

PacifiCorp should respond in final comments with an explanation of how 'capacity held in reserve' is determined for operational purposes.

4.3.2. FOT AVAILABILITY AND WESTERN RESOURCE ADEQUACY

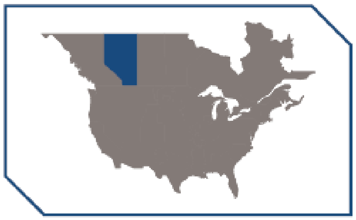
Staff has considered whether PacifiCorp's market depth estimate of 1,425 MW on PacifiCorp's system is appropriate.

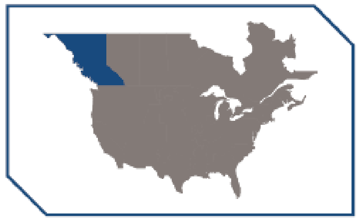
Studies that have evaluated western resource adequacy include the North American Electric Reliability Corporation (NERC) Long Term Reliability Assessment, WECC Power Supply Assessment, Northwest Power and Conservation Council (NWPCC), Bonneville Power Administration (BPA), and Pacific Northwest Utilities Conference Committee (PNUCC).

The most recent NERC and WECC studies show the region to be capacity adequate through 2029.[44] The BPA, NPCC, and PNUCC studies, however, indicate a capacity deficit as soon as 2021.

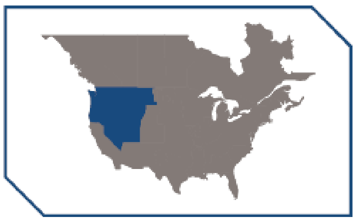
There are several reasons for the different findings between these studies. First, they are assessing different regions. The WECC and NERC studies look at the entire WECC by sub-region and find each sub-region to be capacity adequate through 2029:

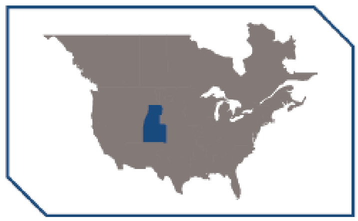
[44] North American Electric Reliability Corporation. 2019 Long Term Reliability Assessment.

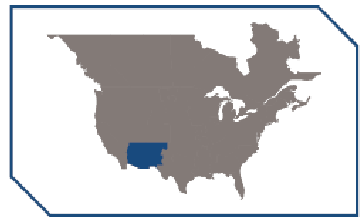

WECC-AB


WECC-BC


WECC-CAMX


WECC-NWPP-US


WECC-RMRG


WECC-SRSG

[45]

The BPA, NPCC, and PNUCC studies consider the 'Northwest Regional Planning Area' (NW Planning Area) as defined by the Pacific Northwest Electric Power Planning and Conservation Act.[46] The area includes the states of Oregon, Washington, and Idaho; part of Montana (west of the continental divide); parts of Nevada, Utah, and Wyoming (within the Columbia River drainage basin); as well as any rural electric cooperative customer served by BPA on the effective date of the Act. [47]

[48]

[45] North American Electric Reliability Corporation. 2019 Long Term Reliability Assessment.
[46] 2019 PNUCC Northwest Regional Forecast.
[47] The 2019 BPA study does not specify which planning area it uses, although past studies have also used the Northwest Regional Planning Area.
[48] NW Planning Area. 2019 PNUCC Northwest Regional Forecast. Page 7.

Second, the WECC and NERC studies may not be accurately modeling the operational characteristics of the hydro resources in the region. The Power Council's GENESYS model is designed to accurately capture the impacts and costs of non-power related constraints placed on the operation of hydroelectric facilities, whereas the model used by WECC may be less nuanced in this regard.[49] Specifically, it is unclear to Staff whether WECC's models reflect the limits on dispatch associated with environmental regulations and other considerations. Staff finds that any errors in the modeling of hydro resources could have a substantial impact on the regional capacity estimate, since 37 percent of the capacity resources in the Northwest Power Pool (NWPP), and 22 percent of the capacity resources in the WECC are hydroelectric.[50] Given the quantity of hydro capacity in the WECC, the WECC model would have to overestimate the capacity contribution of hydroelectric resources by about 10 percent, or 4,215 MW, before the error would result in an actual margin below the WECC-wide reference reserve margin of about 13 percent.[51]

Just as there are unresolved concerns around the WECC modeling of hydroelectric resources, it is unfortunately not at this time possible to rely on the NWPCC's analysis to determine whether the forecast regional capacity deficit in the NW Planning Area is likely to result in any real problems. This is because of the Council's assumptions about imports to the Pacific Northwest (PNW) region. The Council's current methodology models a maximum of 2,500 MW of import capacity, entirely from California. Staff finds this to be an unnecessarily conservative estimate of the capacity available for import from the rest of the WECC. Based on the WECC study, there will be a total of 27,353 MW surplus capacity available throughout the WECC through 2029.[52] This is equivalent to a 15.3 percent planning reserve margin for the region as a whole. The current Council study does not report any transmission constraints that could prevent that excess capacity from being imported to the PNW region.

In conclusion, PacifiCorp's market depth estimate of 1,025 MW available in its Western BAA to serve peak load does not appear to be unreasonably high, especially given the concerns Staff has raised with the recent modeling to substantiate a regional capacity shortfall.

4.3.3. PLANNING RESERVE MARGIN

Staff finds that the Company's use of a 13 percent planning reserve margin appears reasonable based on the analysis in Appendix I. Staff commends the Company's excellent reporting of the quantitative analysis that went into this calculation.

4.3.4. DISTRIBUTED STANDBY GENERATION

Staff greatly appreciates PacifiCorp's work toward beginning a Distributed Standby Generation program, as recommended by Staff in opening comments. The Company reports that it will begin to develop a 'program design that can be communicated to customers to gauge their potential level of participation.'[53]

[49] NWPCC. What is GENESYS? https://www.nwcouncil.org/energy/energy-advisory-committees/system-analysis-advisory-committee/genesys-%E2%80%93-generation-evaluation-system-model
[50] North American Electric Reliability Corporation. 2019 Long Term Reliability Assessment.
[51] Calculated by Staff as a demand-weighted average of the reference margin levels in each WECC sub-region.
[52] North American Electric Reliability Corporation. 2019 Long Term Reliability Assessment.
[53] PacifiCorp Reply Comments. Page 49.

Recommendation:
Staff requests PacifiCorp reply in Final Comments regarding a proposed timeline for completing a program design to gauge potential customer interest, as well as a timeline for reporting to the Commission on the findings of this assessment.

4.4. LOAD FORECAST

4.4.1. LOAD FORECAST

In opening comments, Staff noted three concerns it identified in PacifiCorp's 2019 Load Forecast. The first was that Staff believed the Company could improve on its transparency and documentation for the load forecast. The second was the change in the residential customer count forecast, described by the Company to improve model accuracy, and the last was the use of indicator variables without a documented econometric reason for their inclusion. PacifiCorp in reply comments responded to the first two concerns and provided Staff with more detail on the third through discovery.

Transparency and Replicability
PacifiCorp agreed in reply comments that they could take steps to improve the transparency of their load forecast process. They committed to providing more information to interested parties and to engage with stakeholders on how to best facilitate stakeholder review where sensitive business information needs to be protected. Staff appreciates the Company's willingness to work to improve transparency and stakeholder review. Staff will monitor the Company's progress in the area in PacifiCorp's newly filed rate case and upcoming IRPs.

Customer Count Changes
In reviewing the Company's revised residential customer count model, Staff did not see the stated improvement in accuracy represented by the Company in its initial IRP. After reviewing the model further, Staff continues to find mixed results in differing metrics commonly used to identify in-sample improvements in forecast accuracy. However, as PacifiCorp noted in its reply comments, differencing the data can solve for stationarity issues in the regression by stabilizing the mean. The updated model also uses household numbers as an input as opposed to population. The use of the household data can provide more direct correlation with baseload demand, but population data can be better at parsing out incremental demand beyond the baseload. In reviewing the difference between the two inputs, Staff found slight advantages in using household data as opposed to population and as such Staff supports the use in the model.

Given that the updated methodology provides a more econometrically stable forecast, Staff finds the Company's updated methodology reasonable, even if accuracy improvements are limited.

The Use of Indicator Variables
In response to Staff Data Request (DR) No. 169, the Company noted that it first identifies outliers by visually examining the residuals of the model. It then attempts to identify the cause of the outlying data-point. If the source of the anomaly is identified then the data is corrected, and if it is not, then an indicator variable is used to keep the data-point from influencing the forecast.

Staff has a couple concerns with this methodology. The first is that the data correction is not documented for stakeholder review. These data-points may in fact be an error, or they could indicate information which would be beneficial to the model's performance. Staff recommends that the Company provide the raw data along with the corrected data in its workpapers to allow stakeholders to review the data cleansing process. The second is that the indicator variables are not always consistent across forecasts. Being that these indicator variables are viewed as unidentifiable anomalies, they should not be dependent on the model specification (given it is reasonable), or updates to inputs. If they are truly errors or anomalies, their presence should be consistent in previous forecasts. If they are not consistent, then perhaps the model is simply not fitting the data correctly. The final and overarching concern is that these particular data-points may provide valuable information to the forecast. By utilizing an indicator variable, they are being removed from influencing the forecast. This may result in either a more accurate or less accurate forecast. In reviewing the impact of the outlier data on the forecasts, the inclusion of indicator variables has a material impact on the outcome of the forecast. As such, the use of indicator variables should be done as sparingly as possible.

Staff recommends that the Company provide the raw data along with the corrected data in its workpapers to allow stakeholders to review the data cleansing process.

Conclusion

In summary, Staff believes, as noted earlier, that the Company's documentation and information could be improved. Staff appreciates the willingness of the Company to continue to work to improve the load forecast transparency. Further, Staff believes that the forecast produced by the Company is reasonable. Staff found the methodology to be econometrically sound, and found minimal suggested improvements following its full review.

4.4.2. PEAK LOAD FORECAST

Staff was able to reproduce PacifiCorp's peak forecast using the inexact description the Company has provided. The coefficients were not an exact match, but the difference in our results from the IRP's estimated parameters were not material to the predicted peak load. Staff finds PacifiCorp's peak forecast methodologically valid for capturing the historical data.

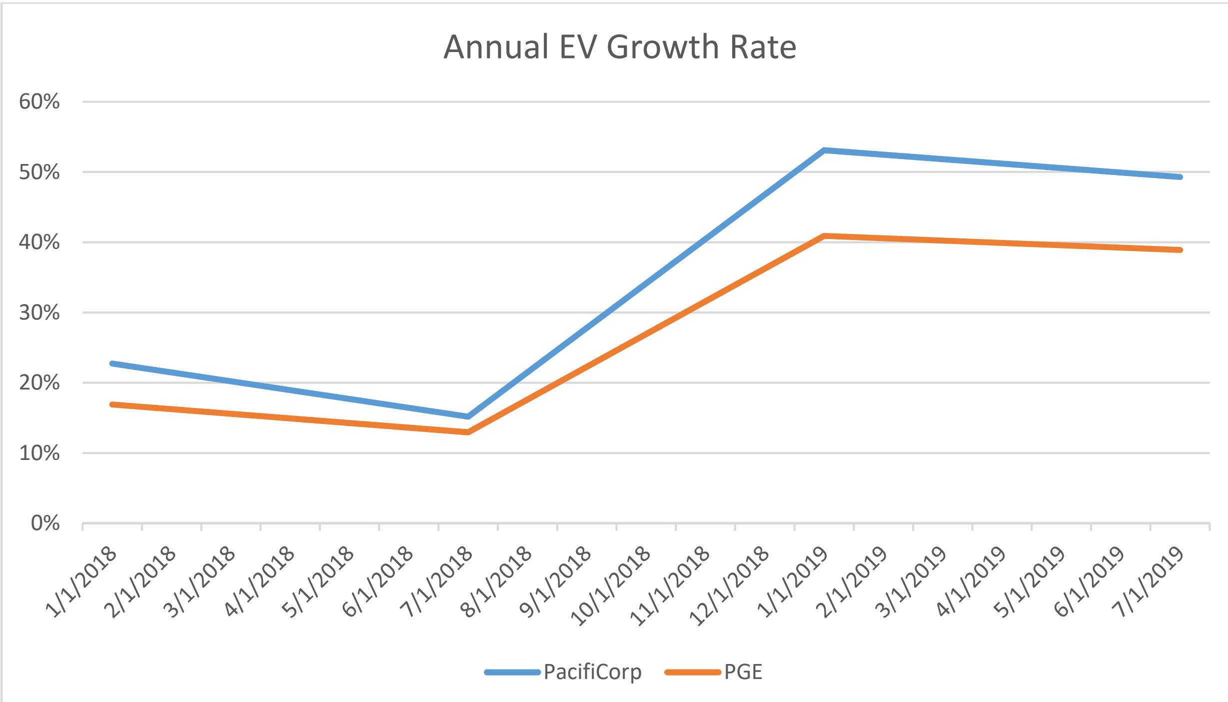
PacifiCorp asserts future demand from electric vehicles is present in the historical data. In the Company's reply comments, PacifiCorp states:

> 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.[54]

The observed growth of electric vehicle (EV) adoption in PacifiCorp's Oregon territory cannot be reasonably expected to find a signal from this historical data if future EV loads do not resemble past

[54] PacifiCorp Reply Comments. Page 45.

loads. The data in the peak load forecast's regression analysis goes back twenty years. Two decades ago, even one decade ago, the number of EVs in the Company's Oregon service territory was much smaller than recent years where PacifiCorp has seen higher EV growth rates than PGE.[55]



In the 2019 IRP, PacifiCorp describes current EV load as "negligible," going on to state that a forecast of EV load is "unavailable."[56] If future EV load grows to a size that is no longer negligible, then PacifiCorp's peak load forecast may possess a model misspecification. Whether the effect of this misspecification is of enough magnitude to materially underestimate peak load is uncertain. The presence of omitted variable bias in a forecast often has no meaningful impact on the predicted variable.[57]

A forecast of EVs in PacifiCorp's territory is available. The Company has provided one in its Transportation Electrification Plan.[58]

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[55] Oregon Department of Environmental Quality. *Electric Vehicles in Oregon* July 14, 2017, page 4;
Oregon Department of Environmental Quality. *Electric Vehicles in Oregon* August 31, 2017, page 5;
Oregon Department of Environmental Quality. *Electric Vehicles in Oregon* May 14, 2018, page 4;
Oregon Department of Environmental Quality. *Electric Vehicles in Oregon* September 23, 2018, page 4;
Oregon Department of Environmental Quality. *Electric Vehicles in Oregon – End of 2018* April 19, 2019, page 3;
Oregon Department of Environmental Quality. *Electric Vehicles in Oregon – End of June 2019* August 23, 2019, page 3.
[56] PacifiCorp 2019 IRP. Pages 61-62.
[57] Allison, Paul. *Prediction vs. Causation in Regression Analysis.* Statistical Horizons July 8, 2014, page 1.
[58] PacifiCorp. *Transportation Electrification Plan.* February 3, 2020, page 3.

Table 1. Pacific Power Oregon Average Light-Duty Forecast Through 2025

Light-Duty Vehicles Average Forecast Through 2025							
	2019	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Cumulative EVs	5,558	7,729	10,385	13,427	16,771	21,342	26,630

PacifiCorp expects to have as many EVs in its Oregon service territory in 2023 as PGE had when PGE filed its 2019 IRP. PGE did not consider this load negligible.[59]

If we were to assume half of PacifiCorp's forecasted EV owners in 2023 will charge their vehicles at a level 1 rate of 1.4 kW, 40 percent will charge at a level 2 rate of 6.6 kW, and 10 percent will charge at a direct current rate of 50 kW, then the average capacity demand per EV would be 8.34 kW. If 75 percent of these EVs charged at the same time, this would amount to around 100 MW of new Oregon load in 2023. By 2025, it would be 167 MW.

If this charging were to occur on the morning or evening of these years' peak days, PacifiCorp's EV forecast predicts new peak demand that might not be captured in the econometrics of the Company's peak load forecast.

Recommendation:
Staff requests PacifiCorp reexamine the peak load forecast to incorporate the Company's EV forecast.

4.5. TRANSMISSION

Parties' Initial Comments

Several parties, including Sierra Club, AWEC, NWEC, Mr. Gail Carbiener, and Staff expressed concerns with PacifiCorp's transmission Action Items. Sierra Club stated that there is a disconnect between the generation and transmission Action Items because Gateway South and the Utah reinforcement projects are tied to resource acquisitions that the Company is not committed to developing.[60] AWEC had similar apprehensions, asserting that the Company has no resource need during the action plan window, yet identified a preferred portfolio that includes a 400-mile transmission line.[61, 62]

While NWEC applauded PacifiCorp's incorporation of new transmission assessment capabilities into the IRP process, it also noted the high capital costs of transmission and questioned whether sequencing new renewable acquisition, coal retirement, and enhanced demand side management could defer or avoid new transmission builds.

Mr. Gail Carbiener opposes the construction of the Boardman to Hemingway (B2H) transmission line.

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[59] PGE. *2019 Integrated Resources Plan.* July 19, 2019, page 262.
[60] Sierra Club Opening Comments. Page 1.
[61] Sierra Club Opening Comments. Page 5
[62] AWEC Opening Comments. Page 1.

Finally, Renewable Northwest did not specifically mention transmission but mentioned the role of interconnection constraints in limiting RFP procurement.

PacifiCorp Reply Comments

In Reply Comments, PacifiCorp noted stakeholder concerns with its Action Item to build Energy Gateway South (EGS) without knowing the results of the upcoming All-Source RFP. PacifiCorp replied that EGS is an element of the Company's least-cost, least-risk preferred portfolio and the associated Action Item should be acknowledged. The Company stated that the results of the All-Source RFP will determine whether EGS should be pursued.

PacifiCorp also addressed the interaction of its transmission planning with regional planning processes, explaining that it is 'not appropriate to rely solely on the NTTG planning process to determine the benefits of a particular project for PacifiCorp.'[63]

Regarding Staff's concerns about endogenous transmission selection, the Company wrote that, 'acknowledgment of specific transmission action items does not mean that the company will move forward with these projects without further analysis. The company will continue to update its analysis and only move forward with items that continue to provide a least-cost, least-risk portfolio.'[64]

4.5.1. ENDOGENOUS SELECTION OF TRANSMISSION INVESTMENTS

Only a limited number of transmission upgrades were available to be endogenously selected by System Optimizer. PacifiCorp has explained that B2H and Segment E were not available for endogenous selection because they create changes to more than two transmission 'nodes.'[65] When Staff asked the Company to further describe the limitations in System Optimizer that prevent the Company from allowing B2H to be selected endogenously, the Company focused on explaining the Borah to Hemingway to Summer Lake transmission topology path and did not allow for more differentiated flow across Path 14 to interconnect with BPA's network integration transmission service (NITS). The Company focuses on Borah to Summer Lake flow as a limiting factor in determining benefits to B2H.

In addition, the Company was unable to provide any comments in response to Staff's request to model the completion of B2H with earlier energization dates or allowing B2H to be paired with PTC wind located near the Western Balancing Authority Area. PacifiCorp's modeling did not consider a 2024 or alternative energization date for B2H. The Company stated that "As a participant in the permitting phase of the project, PacifiCorp cannot control the in-service date."[66] However, PacifiCorp has modeled a variety of retirement dates with co-owned coal resources throughout its IRP cycles. The Company has also electrically modeled B2H energization in the past, with energization dates at least as early as 2016. It is unclear why the Company cannot test different energization dates. Staff is disappointed that this IRP considered the potential for EGS to connect to PTC wind in 2024, but did not perform a similar analysis for B2H.

[63] PacifiCorp Reply Comments. Page 33.
[64] PacifiCorp Reply Comments. Page 34.
[65] PacifiCorp Response to Staff DR 91.
[66] PacifiCorp Reply Comments, page 36.

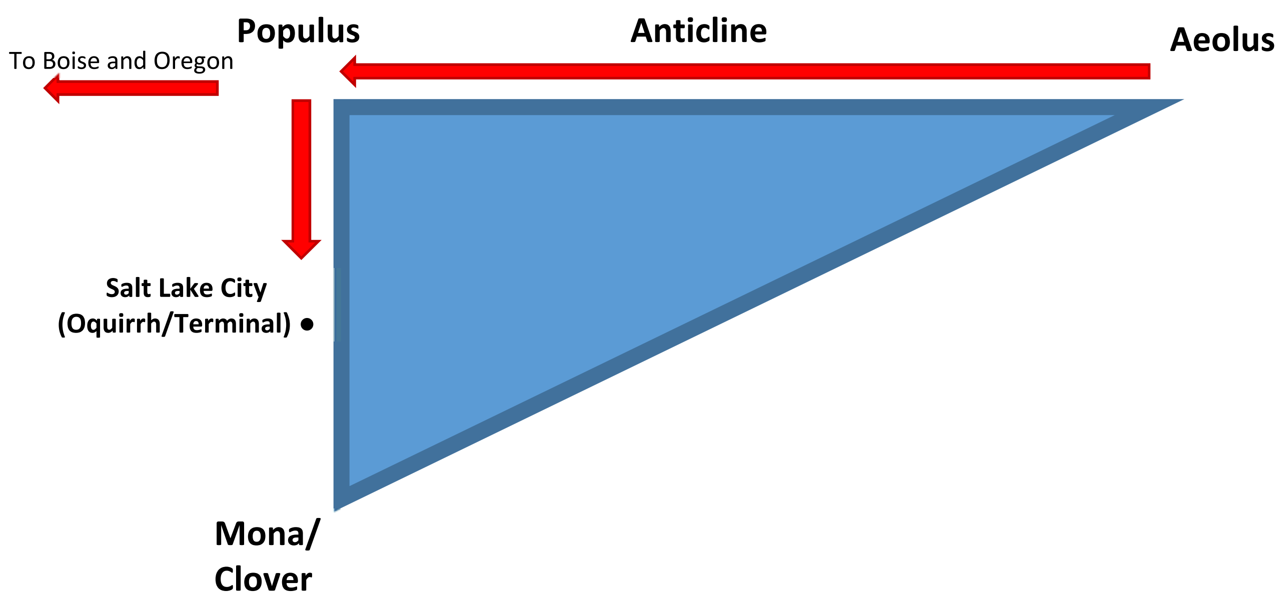
Recommendation(s):

The Company should provide a clear explanation of why the B2H line cannot be modeled endogenously as a simple connector between the Hemmingway bubble and the BPA NITS bubble in the IRP topology.[67]

4.5.2. HOW MUCH WIND AND TRANSMISSION SHOULD OREGON PAY FOR?

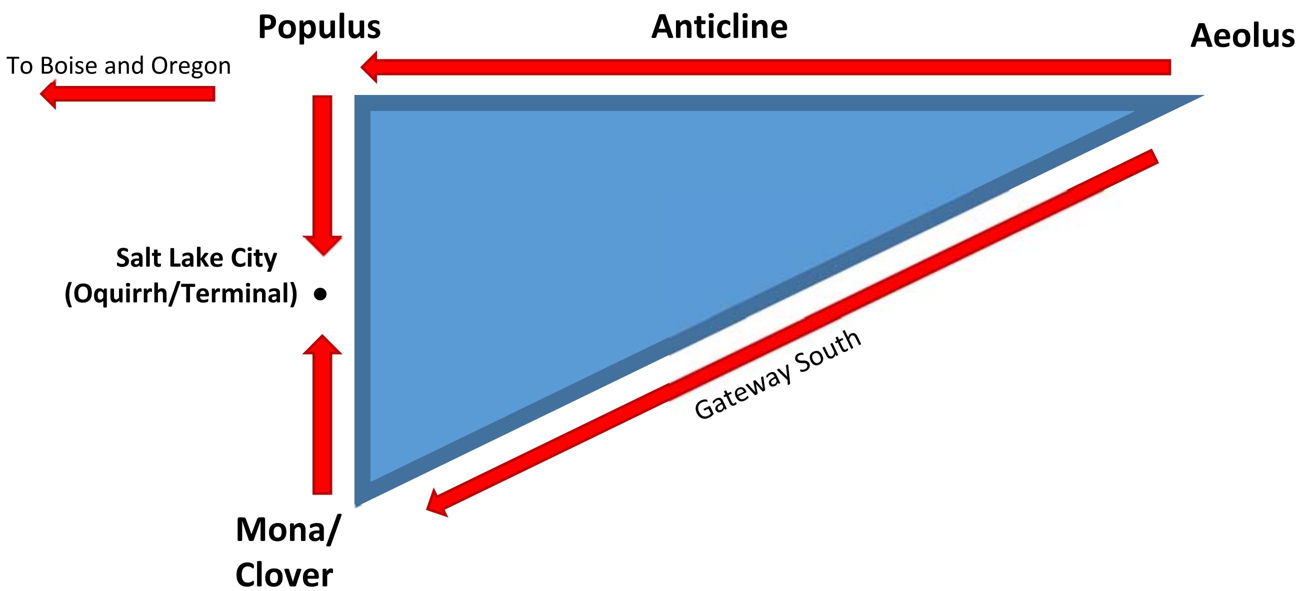
In Initial Comments, Staff raised the issue of the value of Gateway South to Oregon customers.[68] In its Reply Comments, PacifiCorp stated that the Gateway South Project increases the reliability of the central Utah transmission system while also supporting the significant transfer capability of the Energy Gateway South Project.[69] Below are very simplified graphics demonstrating basic topology of Gateway South and associated transmission flow in the region. Aeolus-to-Anticline is the line segment D.2, which will be completed this year and will enable an additional 950 MW of transfer capability. Anticline-to-Populus is segment D.3, which has not been constructed. The line pointing South from the Populus substation to Salt Lake City is Populus to Terminal (Segment B of Gateway Central), which was energized in 2010. There is also an existing line from Mona to Oquirrh (Segment C of Gateway Central), also represented by Salt Lake City, and this was energized in 2013. The red arrows indicate power flows.

Figure 4.2 – "The Triangle" without Gateway South



[67] Transmission topology is shown in the PacifiCorp 2019 IRP, on Page 175.
[68] Staff Opening Comments, page 47.
[69] PacifiCorp Opening Comments, page 35.

Figure 4.3 – "The Triangle" with Gateway South



In Opening Comments, Staff pointed out that the selection of Gateway South is tied to the production tax credits. That is, the economics favors the wind, but Gateway South is needed to facilitate interconnection and flow of the wind because without it, the system would suffer contingencies. In other words, the current transmission system cannot support the additional 1,920 MW of wind, which is what System Optimizer selects. However, as the graphics show, Gateway South will also reinforce Utah load. *Figure 4.3* demonstrates that additional power can get to Salt Lake City via Gateway South, the new wind, and the already existing path that consists of Segment C, Mona to Oquirrh.

Energy Vision 2020 is a relatively new concept to PacifiCorp's long-term planning,[70] but Energy Gateway and its reliability function predates Energy Vision 2020. Prior to the positive economics of the production tax credits, Energy Gateway has been modeled largely for reliability and reinforcement. Its purpose has never been solely about moving renewables across the West. This was the point of Segments D, E, and H. Gateway South does facilitate additional wind, and the nearly 2 GW of Wyoming wind modeled in the IRP will not be able to interconnect without it. However, the Commission has already acknowledged Segment D.2 in the 2017 IRP, which will facilitate an additional 950 MW of East-West transfer capability. In the 2017 IRP Update, the Company indicated it was on track to build over 1300 MW of wind that the acknowledged D.2 will facilitate.

[70] PacifiCorp 2019 IRP. Page 3.

In the 2019 IRP, the Company's preferred portfolio selects another 4,600 MW of new wind resources, more than 6,300 MW of new solar resources, and more than 2,800 MW of battery storage through 2038.[71] With Gateway South and the completion of both Segments D.2 and D.3, PacifiCorp will be enabling an additional 3000 MW of transfer capability across the triangle, but the Company cannot justify the economics of this transmission buildout without the wind. In addition, while Gateway South only allows an additional 1700 MW of transfer capability, System Optimizer allows it to enable 1920 MW of capacity[72] because the intermittent nature of the wind allows for the possibility of overbuilding resources.

In Staff's view, the primary question is whether a transmission line intended to enable 1700 MW of transfer capability, and almost 2,000 MW of additional wind resources is a reasonable, least-cost, least-risk path forward. Staff reiterates that in the 2017 IRP, the Commission already acknowledged nearly 1 GW of transfer capability and upwards of 1 GW of additional renewable buildout. PacifiCorp's justification for Gateway South is that additional wind cannot be interconnected without it, and that the wind needs to be installed before 2023 to take advantage of the production tax credits. PacifiCorp appears to be employing a "the more you build, the more you save" approach in its IRP, and is leveraging the urgency of expiring production tax credits to persuade stakeholders into accepting this solution as least-cost, least-risk. As Staff has explained in its comments on the Energy Gateway South Action Item, PacifiCorp's case for the cost-effectiveness of building EGS in order to connect cost-effective PTC wind for customers is dubious when compared to portfolios that include near-term PTC wind without construction of EGS.

In addition is the reinforcement role of Gateway South for Salt Lake City. While Gateway South will technically enable nearly 2,000 MW of additional wind, the reinforcement benefit will belong to Utah. For example, if Mona-to-Oquirrh is out, D.2 is out, or some other line to Salt Lake City is out, the Company will be able to re-route power across Gateway South. PacifiCorp appears to have co-mingled the reinforcement and renewable buildout benefits in this IRP.[73] In PacifiCorp's 2017 IRP update, the Company stated that until then, Segment D.2 was not cost effective.[74] The Company is employing this same logic for Gateway South in order to procure even more transmission and wind. Staff is left questioning the limits of what the Company will request. There is still Segment D.3, Segment E, and B2H which PacifiCorp has indicated it still intends to build but did not include in the Preferred Portfolio.

Further, even though Gateway South only enables an additional 1700 MW of transfer capability, the Company's IRP modeling enables 1,920 MW of wind. This exceeds transfer capability. Coupled with D.2 and the renewable buildout from the 2017 IRP, the Company will have requested upwards of 3,000 MW of imminent Wyoming wind and the transmission necessary to support it, and over 1 GW of wind and associated transmission will be energized by the end of the year.

Staff must recommend against acknowledgement of Gateway South. In Staff's opinion, a lower risk approach would be to postpone Gateway South, which Staff has indicated could save ratepayers $355 million or more if delayed until 2030 or later. Further, Staff reiterates that failure to include all segments of Energy Gateway as options in System Optimizer provides a limited scope through which to judge the

[71] PacifiCorp's 2019 IRP. Page 7.
[72] PacifiCorp's 2019 IRP. Page 169.
[73] See various discovery responses from PacifiCorp in Staff Attachment A from Staff's Opening Comments.
[74] i.e., the production tax credits enabled the cost effectiveness of D.2.

cost and risk of the Company's preferred portfolio and make an informed decision on the best path forward. For example, if System Optimizer was given the option to construct B2H in 2024, perhaps the model would have chosen B2H over EGS in that year. There is currently no way to know.

4.5.3. COSTS OF THE ENERGY GATEWAY TRANSMISSION PROJECT

It has been difficult for Staff to obtain public numbers on the cost of Segment D.2, but PacifiCorp has provided this information confidentially. The current estimated total cost of Segment D.2 is [**Begin Confidential]** [redacted] [**End Confidential]** In contrast, the total cost of Gateway South is nearly $1.8 billion[75] for roughly a per-mile cost of $4,382,082. However, these are rough numbers. The total cost of all of the transmission items in PacifiCorp's preferred portfolio is $2.792 billion. This does not include what has already been spent on Segment D.2, or the future D.3., Segment E, or B2H. Using very rough estimates from PacifiCorp's confidential spreadsheet, the total cost of Energy Gateway will end up being around **[Begin Confidential]** [redacted] [**End Confidential]**

PacifiCorp has failed to demonstrate adequately how Energy Gateway is provides a net benefit to Oregon customers, especially given the total cost for the entire Energy Gateway buildout of about **[Begin Confidential**] [redacted] **[End Confidential]** Staff is concerned that PacifiCorp is requesting ratepayers fund a series of very expensive transmission investments before they are truly needed to serve customers.

Recommendation(s):

In Final Comments, the Company should confirm Staff's estimate of Energy Gateway costs, or provide an alternative estimate.

4.5.4. THE COMPANY DID NOT RESPOND TO STAFF'S CONCERN REGARDING UNDERUTILIZATION OF GATEWAY SOUTH.

Since most of the flow across Aeolus to Mona is expected to flow Northeast-to-Southwest, the line could potentially be underutilized, making it an inferior line as compared to a bidirectional resource. When Staff asked the Company to provide anticipated utilization of Gateway South based on internal PacifiCorp engineering studies, the Company stated that the granularity Staff requested could not be provided, and pointed Staff to a path rating analysis of Gateway South completed in 2010.[76] The path rating analysis did not explicitly predict flows, but it was clear from the study that the primary stressors across Gateway South was Wyoming wind flowing from Northeast to Southwest.

Based on confidential output files from the Planning and Risk (PaR) model, Staff was able to determine the forecast of utilization across Gateway South—an average **[Begin Confidential]** [redacted] **[End Confidential]**. This means Gateway South would still only be utilized at around **[Begin Confidential]**

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[75] PacifiCorp 2019 IRP, Table 1.1. Page 8.

[76] PacifiCorp response to Staff DR 155.

[redacted] **[End Confidential].** This is also only for a unidirectional, Northeast to Southwest flow. Staff could not identify any flow data for Southwest to Northeast flow.

Recommendation(s):
In Final Comments, the Company should address Staff's concerns regarding the underutilization of Gateway South.

4.5.5. THE COMPANY HAS NOT EXPLAINED HOW ITS TRANSMISSION PLANS ARE CONSISTENT WITH REGIONAL PLANNING PRIORITIES.

Regarding the regional benefits of Energy Gateway, PacifiCorp stated that it is not appropriate to rely solely on the NTTG planning process to determine the benefits of a particular project for PacifiCorp. However, Staff clarifies that it never suggested relying solely on the NTTG process. Staff wanted to know how PacifiCorp's IRP is consistent with regional planning priorities.

Recommendation(s):
In Final Comments, The Company should address Staff's concerns explaining how the IRP is consistent with regional planning.

4.6. LOAD RESOURCE BALANCE, CAPACITY CONTRIBUTION

In PacifiCorp's Initial Load Resource Balance table for capacity, which includes a 13 percent Planning Reserve Margin (PRM), PacifiCorp is reliant on short-to-medium term market purchases for capacity beginning in 2020. The 1,468 MW of assumed-available market capacity assumed is exhausted by 2028, resulting in a system deficit of 839 MW in the summer and 0 MW in the winter. The winter system deficit of 399 MW occurs in 2029.[77]

In Initial Comments, Staff noted that the load and resource balance table for capacity can be an important touchstone for determining whether the preferred portfolio is addressing a need for new capacity resources, or potentially addressing another need (flexibility) or opportunity (economic benefit.) Staff reported some initial concern with the capacity contribution estimates for existing renewables, the direct access forecast, and the forecast of private generation and Qualifying Facilities (QF). In ongoing investigation, Staff found that the load and resource balance for capacity does not appear to have any major inaccuracies, although there is room for improvement.

Capacity Contribution of Existing Renewables
After a review of the capacity contribution workpapers provided by PacifiCorp in response to Staff DR 189, Staff is still unable to thoroughly assess the Company's calculation for the capacity contribution of renewables in its load resource balance. The workpapers provided by PacifiCorp included hard-coded numbers and poor labeling that were not sufficient to develop a full understanding of the methodology.

[77] PacifiCorp 2019 IRP. Page 115.

Staff's concern about the capacity contribution calculation of renewables is that PacifiCorp has not made the calculation clear, and that it may be underestimating the capacity contribution of renewable resources. PacifiCorp's IRP states:

> For the purpose of reporting the capacity contribution of wind and solar resources in the load and resource balance, PacifiCorp first calculated the contribution of all other resources in the portfolio, using the methodologies described in this section. The remaining capacity in the load and resource balance, up to PacifiCorp's thirteen percent planning reserve margin, is attributable to wind and solar.[78]

Staff needs to understand how "the remaining capacity in the load and resource balance" that is "attributable to wind and solar" in the Chapter 5 Load and Resource Balance Table is defined and calculated. Is it defined as the total amount of capacity that the Company actually expects to be available in a given year, in the absence of new resource additions? That would seem to be a reasonable methodology, and Staff would need to know how that amount of total available capacity was estimated.

The answer to the above question will determine Staff's opinion of the capacity contribution calculation for existing renewables. PacifiCorp should either reach out to Staff with an answer to this question or provide an answer in final comments.

QF Capacity

For an example of Staff's concern regarding QF capacity in the load and resource balance table, if the average amount of new QF capacity from the last four years (296 MW) is added in each year of the planning timeframe, then in 2028 there will be 2,271 more MW of QF nameplate capacity online than PAC's LRB table predicts. If these renewable resources have a capacity contribution of 15 percent, that would represent 340 MW additional capacity contribution.

Private Generation Capacity

If private generation grows at the rate Staff views as reasonable, then 37 percent more MW may be online in the summer of 2028, resulting in approximately 100 MW additional capacity contribution.

Community Solar Capacity

A high-case community solar forecast would add 64 MW of Oregon solar nameplate capacity. If these renewable resources have a capacity contribution of 15 percent, that would represent about 10 MW additional capacity contribution.

Conclusion

If new QF, private generation, and community solar resources come online according to reasonable forecasts, then the Company's capacity deficit could be reduced by about 420 MW in 2028. However, this would not be enough of a change to counteract the 839 MW deficit in that summer.

[78] PacifiCorp 2019 IRP, Page 110.

There is still some uncertainty around the capacity contribution calculation for existing renewables and the potential effects of this calculation on the capacity deficit year. In conclusion, Staff finds that the load resource balance table likely provides a reasonable estimate of the Company's first capacity deficit year, but Staff will continue to review the methodology for calculating the capacity contribution of existing renewables.

Recommendation:

Before the acknowledgement decision in this docket, Staff requests the Company provide a phone workshop for Staff to fully understand how the capacity contribution of renewables was developed for the Chapter 5 Load Resource Balance Table (without new resource additions), or provide a thorough answer to Staff's question in the Company's final comments.

In future Load and Resource Balance Tables, forecasts should include new QFs and renewing QFs, and any new customer preference program capacity.

4.7. QUALIFYING FACILITIES IN THE PREFERRED PORTFOLIO

In opening comments, Staff recommended that PacifiCorp should update the preferred portfolio with a forecast of new QF capacity that reflects historical trends. PacifiCorp's reply comments argued that it cannot require a QF to renew, which would make a forecast problematic from a planning perspective, and that past QF trends are not a reasonable predictor of future QF development activities.

Staff maintains its position that a QF forecast based on historical trends of QFs that achieved commercial operation in recent years is a reasonable to approach to long term resource needs. For example, from 2015 to 2019, an average of ~300 MW of new QF capacity came online in each year. A simple forecast of 300 MW new QF capacity in each year of the planning horizon could be a reasonable way to treat the uncertainty of how much QF generation will come online throughout the planning timeframe. Even a forecast of ~60 MW in each year, the lowest amount of annual new QF contracts over the last four years, would be preferable to a forecast of zero new QFs.

Staff also finds it plainly apparent that the Company should assume renewal of existing QF contracts, or at least a percent of contract renewal proportionate to recent renewal trends.

PacifiCorp's concerns about the cost implications of including new and renewing PURPA contracts in the IRP should not prevent the company from utilizing the most realistic planning assumptions. PacifiCorp expresses concern that QFs are compensated based on avoided costs of resources the Company would otherwise acquire, and that therefore new QF forecasts should not be included in the preferred portfolio. This is a reasonable concern; however, the Company could easily include QF renewals in its Load Resource Balance study and preferred portfolio, while using a separate calculation of system costs without new QF resources to determine QF avoided costs.

4.8. COAL RETIREMENTS

Sierra Club's opening comments argue that PacifiCorp should have selected a portfolio that retires Jim Bridger in 2025, but several errors and unrealistic modeling assumptions resulted in the selection of a portfolio that retires the units in 2023, 2025, and 2037 instead. Staff has reviewed Sierra Club's arguments and finds them to have some merit.

First, the 500 MW of reliability resources required in these portfolios may be excessive. Staff has one remaining question for the Company before making a final determination as to the reasonableness of the 500 MW reliability resources, as described in more detail in these final comments in section 4.3.1. Before the reliability resources were added, portfolio P-36 with Jim Bridger retirement in 2025 was $120 million less expensive than P-45. After the reliability resources were added, however, P-36 was $73 million more expensive. Therefore, it seems reasonable to conclude that the 500 MW of reliability resources contributed to the selection of p-45.

Second, Sierra Club argued in Initial Comments that Jim Bridger mine costs are in error in the preferred portfolio. In Reply Comments, PacifiCorp acknowledged the error, and disclosed that it increased the PVRR costs of P-45 by about $29 million, resulting in P-48 taking the place of the least-cost portfolio in the 2019 IRP. P-48 has the same coal retirement schedule as P-45, except Jim Bridger 3 & 4 retirements occur in 2033 instead of 2037. PacifiCorp's noted that the error would not impact the 2019 Action Plan.

Third, Sierra Club argues that Jim Bridger fuel price assumptions have been underestimated in this IRP, with a growth rate lower than historical levels. PacifiCorp's response in reply comments was that fuel costs used by Sierra Club were based on PacifiCorp's reports to the EIA, which include costs such as depreciation, depletion, and amortization that are not included in the IRP. PacifiCorp argues that as a result, Sierra Club's comparison is not apples to apples. However, PacifiCorp does not address Sierra Club's argument about the *trend* of fuel costs at Jim Bridger. Sierra Club notes that the trend of fuel costs reported to the EIA has been moving upward, with costs increasing 99 percent from 2009 through 2018. PacifiCorp's IRP forecasts Jim Bridger fuel cost **[Begin Confidential]** [redacted] **[End Confidential].** While Sierra Club's comparison may not be apples to apples, the trend Sierra Club observes may still be relevant, and it does warrant a closer look at Jim Bridger fuel costs. Staff notes that the fixed costs of the Jim Bridger mine are distributed among the tons of coal produced, which are adjusted in response to changes in demand at the Jim Bridger plant.[79] **[Begin Confidential]** [redacted] **[End Confidential]**

Sierra Club states that the fixed O&M costs for solar in the 2019 IRP of $22/kw-yr are about twice the cost of $9 - $13/kw-yr estimated by Lazard and NREL, and this impacts coal retirement decisions in the model. In Reply Comments, PacifiCorp replied that the $12/kw-yr is a low estimate and its estimate of solar costs is within industry standards. Staff finds that, because PacifiCorp's fixed O&M costs of about $22/kW-yr are about twice the low-end Lazard estimate of $12/kW-yr, this may have been a substantive cost over-estimation that could indeed have reduced the economic benefits of coal retirements in the 2019 IRP by making replacement solar resources more expensive than necessary. Staff appreciates PacifiCorp's willingness to revise its costs in the next IRP as informed by the next RFP.

Sierra Club writes that securitization could save customers $131 million if Jim Bridger is retired in 2025. Staff agrees that securitization could provide benefits for PacifiCorp customers by shielding them from the rate impacts of accelerated depreciation from economic coal retirements.

[79] See PacifiCorp's opening testimony in Docket No. UE 307. PAC/200, Ralston/15-16.

In conclusion, Staff finds that while Sierra Club's analysis shows that early retirements at some coal units may be even more economic than the 2019 IRP analysis showed them to be, the difference to ratepayers is likely not substantial enough to justify any changes to the 2019 IRP Action Plan. However, it could be valuable to include the coal retirements associated with P-48 in the RFP analysis, to reflect the most accurate analysis.

Recommendation(s):
PacifiCorp should use coal retirements from P-48 in its 2020AS RFP.

4.9. PRIVATE GENERATION

In opening Comments, Staff raised concerns that PacifiCorp's private generation (PG) forecast may be understating the capacity contribution of PG resources over the planning horizon. Staff specifically noted that:

- The customer adoption curves used as an input in Navigant's PG forecast were more conservative than those used by National Renewable Energy Laboratories (NREL's) dGEN model;[80]
- The PG customer adoption models assumed that no PG incentives will be extended or introduced;[81]
- The winter contribution to peak for PG was drastically lower than the summer in the load resource balance;[82] and
- It was unclear whether the Company included customer-sited storage in its PG forecast.[83]

PGE Forecast Trajectory

In response to Staff's concerns about the customer adoption curves and assumptions around PG incentive policies, PAC provided a brief explanation of the benefits of using economic drivers to inform its long-term PG forecast.[84] PAC did not directly address the disparity between the Company's customer adoption curves and NREL's less conservative assumptions. Further, the Company declined to provide the proprietary third-party models underlying the forecast with which Staff could understand the impact of NREL's customer adoption assumptions on the PG forecast.[85]

In addition, PAC's Reply Comments note the Company's decision not to, "speculate on specific policy drivers that are not identified and that would necessarily differ by state."[86] Staff finds that this is reasonable for the low PG adoption case, but cannot agree that a reasonable base case should assume that all policies, including for example the Oregon Public Purchase Charge renewable incentives, will sunset without any extensions or replacements. As noted in Staff's Opening Comments, this assumption

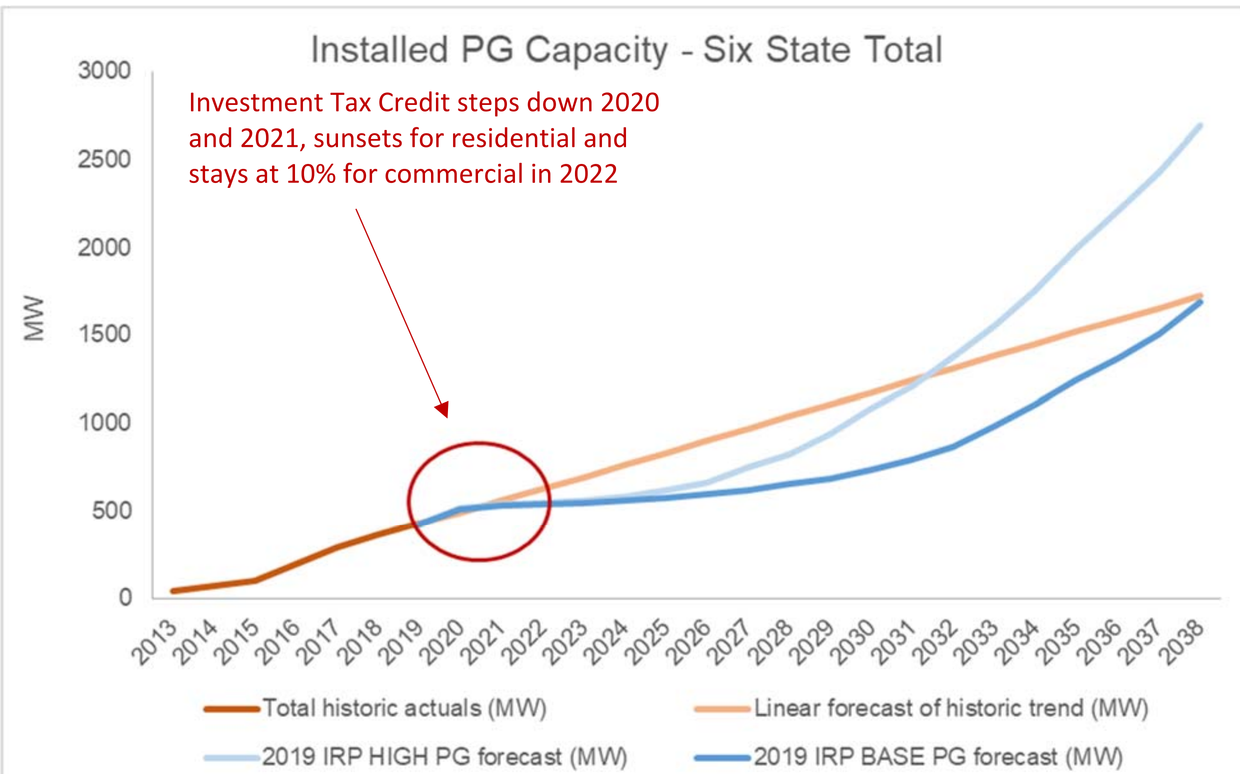
[80] Staff Opening Comments. Page 20 -21.
[81] Staff Opening Comments. Page 23.
[82] Staff Opening Comments. Page 22-23.
[83] Staff Opening Comments. Page 24.
[84] PacifiCorp Reply Comments. Page 45.
[85] PacifiCorp response to OPUC Staff IR No. 147.
[86] PacifiCorp Reply Comments. Page 46.

has already proven to be false with the introduction of a new solar rebate in Oregon in 2019.[87] PAC further notes that the upward trend applied to high PG scenario could reflect a similar increase in adoption if some extension of PG incentive policies is assumed.[88]

These and other economic drivers result in the PG forecast shown in Figure 4.4. While the base and high PG forecasts project a similar or higher level of PG adoption by 2038, Staff finds both forecasts are likely underrepresenting the contribution of PG resources over much of the planning horizon. Specifically, Staff finds that the base PG forecast is, on average, 22 percent lower than a linear forecast of the recent historic trend.

Staff agrees that, if the ITC sunsets as scheduled, customer adoption is likely to dip for a period of time, but finds that it is not reasonable to expect a 94 percent dip in PG adoption in 2022 that does not recover again for eleven years.

Figure *4.4*: Comparison of Historical PG Adoption Trend to 2019 IRP PG Forecast [89],[90]



[87] Staff Opening Comments. Page 23.
[88] PacifiCorp Reply Comments. Page 46.
[89] 2019 IRP PG forecast figures are found in the 2019 PAC IRP, Appendix O – Private Generation Study, pp. D-9 – D-41.
[90] PacifiCorp historic actual PG adoption data was provided in PacifiCorp response to OPUC Staff IR. No. 188—corrected March 3, 2020.

PG Contribution to Peak

Regarding the winter contribution of PG, Staff appreciates PAC's explanation that the stark difference in winter and summer contribution to peak reflected in the Company's load-resource balance is related to the timing of the system peak in each season.[91]

This explanation from the Company highlights the need for PacifiCorp to incorporate PG storage into its long-term planning and operations. By shifting output from PG systems from hours 16 and 17 to hour 18—either onto the grid or to serve onsite load—the Company could reduce its winter peak by more than 100 MW.

In response to Staff questions about standalone storage systems, the Company confirmed that standalone storage PG is likely to impact the Company's long-term capacity needs assessment but did not include it in the PG forecast due to, "uncertainty associated with how customer-sited storage would impact loads when the adoption of a technology is in such a nascent stage."[92] Staff understands that customer storage systems are new to PAC's system and encourages the Company to incorporate this technology into its PG forecast in the next IRP.

Conclusion

Staff finds that the Company is likely understating the ability of PG resources to meet a portion of its needs in the near-to-mid-term by up to 22 percent over the planning horizon. Staff recommends that the Company provide an updated PG forecast that reflects NREL's customer adoption curve assumptions and a reasonable assumption that some level of PG incentives will persist.

If PAC cannot provide the updated analysis requested, Staff recommends that the Company modify its load resource balance to reflect its high PG forecast scenario. Further, PAC should do more to include customer storage in its next IRP. Specifically, PAC should test the impact of storage in two ways:

First, PAC's efforts to include customer storage as a class 1 DSM resource in the next IRP should leverage storage and PG to better align the energy output of PG with the Company's seasonal peaks.

In addition, PAC should further its understanding of customer storage as class 1 DSM resource by implementing a residential storage pilot under OPUC Docket No. UM 1857.

Recommendation(s):

- **PacifiCorp should provide an updated PG forecast that reflects NREL's customer adoption curve assumptions and a reasonable assumption that some level of PG incentives will persist.**
- **If PAC cannot provide the data and analysis requested, Staff recommends that the Company modify its load resource balance to reflect its high PG forecast scenario.**
- **Further, PAC should leverage PG and customer storage to reduce its peak needs in the following ways:**
    - **Model the ability of customer storage to align the energy output of PG systems with the Company's seasonal peaks in its efforts to include customer storage as a Class 1 DSM resources in future IRPs.**

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[91] PacifiCorp's response to OPUC Staff IR No. 148.

[92] PacifiCorp Reply Comments. Page 46.

- **Implement a residential storage pilot under OPUC Docket No. UM 1857.**

5. STAFF RECOMMENDATIONS REGARDING THE NEXT PACIFICORP IRP

5.1. CLIMATE ADAPTATION PLAN

In Initial Comments, Staff recommended PacifiCorp provide a climate adaptation plan in its next IRP. Staff suggested that a robust climate adaptation plan would include reporting on 'n-1' resilience modeling and the expected effects of a multiple-day cold-snap or heat-wave, as well as an assessment of vegetation management and the potential implications of cascading blackouts.

In PacifiCorp's Reply Comments, the Company wrote that Staff's definition of a 'climate adaptation plan' is not clear and that 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.' The Company proposed that any requirements to include a climate adaptation measures are likely better suited to a Commission rulemaking or working group.

Staff appreciates the Company's openness to a discussion and potential future process on climate change adaptation. Staff agrees that a rulemaking or working group would be a holistic approach with stakeholder participation, and finds value in PacifiCorp's suggestion. However, even before any future rulemaking or other process is initiated, Staff requests that the Company include in its next IRP a brief explanation of how it is considering potential future climate change scenarios in its long-term planning. To guide this work and to set a level of expectation, Staff would point PacifiCorp to the conversation around climate adaptation in the Portland General Electric 2016 IRP (LC 66) as an example. [93]

PGE's work was in response to concerns Staff raised in PGE's previous IRP (LC 56), in which Staff asked PGE by the next IRP to do the following:

- Prepare a comprehensive report of climate change planning activities,
- Explain how PGE is incorporating the risks of climate change into its planning;
- Describe what climate change adaptation and mitigation actions PGE is conducting on its own behalf and on behalf of is customers,
- [Complete] a report on any climate change-centered customer engagement activities PGE is currently undertaking.[94]

While the climate report ultimately included in PGE's IRP was a basic study of expected climate trends and risks in the region that did not address all of Staff's requests, it was an important step toward considering the effects of climate change on long-term planning in the region.

[93] *See* LC 66, PGE's Initial IRP Filing, November 2016, *Appendix E, Climate Change Projections in Portland General Electric Service Territory*, p. 387.
[94] *See* LC 56, Staff's Final Comments, July 25, 2014, p. 7

<u>Recommendation:</u>

PacifiCorp should address the following items in the next IRP in order to create transparency around the Company's planning for future climate conditions:

- **Explain how temperatures and hydroelectric forecasts under multiple climate change scenarios have been considered in portfolio sensitivities and/or base cases as appropriate,**
- **Evaluate potential effects of increased temperatures on the operational characteristics and costs of supply side and demand side resources over the resources' expected lifetimes.**
- **Prepare a comprehensive report of climate change planning activities, and**
- **Describe what climate change adaptation actions, if any, PacifiCorp is already conducting.**

This concludes OPUC Staff's final comments

Dated at Salem, Oregon, this 4th day of March, 2020.

Rose Anderson
Senior Economist
Energy Resources and Planning Division

LC 70 / PacifiCorp
December 19, 2019
OPUC Data Request 70

OPUC Data Request 70

Transmission, Battery Storage, Action Plan - Please identify and summarize any analysis performed by PacifiCorp comparing the cost-effectiveness of adding mixes of wind, solar and storage interconnected with existing transmission (though with lesser renewable capacity factors) vs. incremental transmission to more remote mixes of potential higher capacity factor wind, solar and storage. If this analysis has not been performed by PacifiCorp, please so state that fact.

Response to OPUC Data Request 70

The System Optimizer model (SO model) set-ups include existing interconnection capability as well as transmission upgrades. The requested comparison of cost-effectiveness is therefore intrinsic to every model run.

The potential for storage to enhance the efficient usage of existing resources is also intrinsic to the optimization logic. As modeled, stand-alone storage is not considered to require additional interconnection or incremental transmission upgrades to interconnect because these load-shifting resources could be operated within existing transmission rights.

Regarding the remoteness and quality of resource and transmission options, the 2019 Integrated Resource Plan (IRP) considered 20 transmission options in 12 topology bubbles within five states (Idaho, Oregon, Utah, Washington, and Wyoming). Of these options, the 2019 IRP Preferred Portfolio includes transmission upgrades in all five states, including three in Oregon. The selection of a large volume of Wyoming wind (1,920 megawatts) coupled with the Energy Gateway South project is driven partly by the high quality of these renewable resources and availability of federal production tax credits. Please refer to PacifiCorp’s 2019 IRP, Volume I, Chapter 6 (Resource Options), specifically pages 168 and 169, and Volume I, Chapter 8 (Modeling and Portfolio Selection Results), specifically page 247.

LC 70 / PacifiCorp
December 19, 2019
OPUC Data Request 91

OPUC Data Request 91

Transmission, Battery Storage, Action Plan - Given all the benefits of B2H listed on page 78 in the 2019 IRP, please provide a detailed explanation of why the Company did not include B2H in any of its new transmission integration options in System Optimizer.

Response to OPUC Data Request 91

The company interprets the question to be asking why Boardman to Hemingway (B2H) was not included “among” the new transmission options modeled in the System Optimizer (SO) model, as no transmission option is included “in” another modeled transmission option in the 2019 Integrated Resource Plan (IRP). Based on the foregoing understanding, the company responds as follows:

In the IRP topology, the B2H project requires two transmission paths linking three “bubbles” for proper representation. Specifically required are transmission paths from Borah to Hemingway, and from Hemingway to South-Central Oregon / Northern California. Using the transmission option methodology, the SO model cannot endogenously enforce the simultaneous inclusion of both parts of the B2H option when the project is selected. The Hemingway bubbles’ interconnections are essential to the value of B2H, precluding the simplification of the option to only consider a path from Borah to South-Central Oregon/Northern California. Please also refer the company’s response to OPUC Data Request 84, subpart (b).

LC 70 / PacifiCorp
January 29, 2020
OPUC Data Request 132

OPUC Data Request 132

In which years is SO able to select Energy Gateway South in 2019 IRP portfolios? If there is a limitation against selecting the line after a certain year, please explain why.

Response to OPUC Data Request 132

In preliminary cases, the system optimizer (SO) model could select Energy Gateway South beginning 2025 (as a proxy for year-end 2024). Ongoing review of the Energy Gateway South project schedule indicated that this line could be built by the end of 2023, aligning the in-service date with then current production tax credit eligibility deadlines, and that the transmission line could enable additional transfer capability than originally assumed. These updated assumptions were reflected into a subset of preliminary portfolio development cases, where Energy Gateway South was forced to come online by 2024 (as a proxy for year-end 2023), and these results were presented to stakeholders at the June 2019 public-input meeting.

Several stakeholders participating in the June 2019 public input meeting explained that it would be better if the model were able to endogenously select the Energy Gateway South project reflecting updated in-service date assumptions in all portfolio development cases, rather than being forced in at the earlier date among a subset of the portfolio development cases. Upon discovering a modeling issue associated with the treatment of Jim Bridger mine reclamation costs, PacifiCorp communicated in its July 2019 stakeholder conference call that it would be able to accommodate stakeholder feedback by enabling selection of Energy Gateway South as early as January 2024 (as a proxy for year-end 2023) while making corrections for the mine reclamation modeling issue. Consequently, all of the portfolio development cases ultimately evaluated in the 2019 Integrated Resource Plan (IRP) configured with endogenous selection of Energy Gateway South could choose this upgrade as early as 2024 (as a proxy for year-end 2023). The line was available for selection through 2028, recognizing that delays beyond 2028 could increase the risk that rights-of-way grants with the U.S. Bureau of Land Management could be terminated via a rebuttable presumption if not used for a continuous five-year period.

PacifiCorp's IRP team ran subsequent tests of the 2028 end date for Energy Gateway South by enabling selection of the transmission line at any time from 2024 to the end of the study period. In each of these cases, the Energy Gateway South transmission line was selected in 2024, confirming that the 2028 end date was not driving selection of the line in 2024.

LC 70 / PacifiCorp
February 10, 2020
OPUC Data Request 152

OPUC Data Request 152

Regarding PacifiCorp's June 2019 Public Input Meeting Presentation at Page 6, please explain the reasons for the downward adjustment to the cost of Energy Gateway South.

Response to OPUC Data Request 152

The downward adjustment to the cost of Energy Gateway South in the June 2019 Public Input Meeting presentation was driven by a re-evaluation of the proposed route and tower design that enabled a simpler 'guyed vee' tower to be used in certain locations. The result was a reduction in fabricated steel quantities, an improved efficiency installation and a reduction to foundation requirements.

LC 70 / PacifiCorp
February 11, 2020
OPUC Data Request 154

OPUC Data Request 154

Please provide an itemized estimate of all transmission upgrade costs in the Action Plan. Please provide this data in Excel format with cell references and formulae intact.

Response to OPUC Data Request 154

Please refer to the 2019 Integrated Resource Plan (IRP), Volume I, Table 1.1 (Transmission Projects Included in the 2019 IRP Preferred Portfolio) on page 8. The last column of this table shows the assumed cost for each upgrade in parenthesis. Line-item detail has not been developed. A copy of the 2019 IRP can be accessed by utilizing the website link provided below:

https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_I.pdf

OPUC Data Request 155

Please provide the anticipated utilization of Gateway South through 2038 based on any and all internal PacifiCorp engineering studies. In your answer, please provide:

(a) An estimate of expected transmission power flows from Wyoming to Utah across Gateway South.

i. Please provide power flows on the most granular timescale possible.
ii. Please also provide data broken out by average flow in each month of the planning time horizon.
iii. Please also provide average peak and off-peak power flows on EGS by month.

(b) An estimate of expected transmission flows from Utah to Wyoming across Gateway South.

i. Please provide power flows on the most granular timescale possible.
ii. Please also provide data broken out by average flow in each month of the planning time horizon.
iii. Please also provide average peak and off-peak power flows on EGS by month.

(c) In your answer, please include utilization for each user (i.e., PacifiCorp, customer, and third-party) as appropriate.

Response to OPUC Data Request 155

Flow-based analysis has been completed, but it does not provide the granularity being requested. The analysis looks at peak load periods to determine how the transmission system will perform under those peak conditions.

Please refer to the company’s response to OPUC Data Request 158, specifically Attachment OPUC 158 which provides the power flow path rating study report for Energy Gateway South.

LC 70 / PacifiCorp
February 10, 2020
OPUC Data Request 158

OPUC Data Request 158

Please provide a narrative explanation of how PacifiCorp anticipates Gateway South will enhance Utah reliability and redundancy. Please provide each study in PacifiCorp's possession related to the role of Gateway South in Utah reinforcement.

Response to OPUC Data Request 158

The Energy Gateway South 500 kilovolt (kV) transmission line project will provide approximately 1,700 megawatts (MW) of additional transmission capacity from the wind areas of eastern Wyoming to the Clover/Mona area located in central Utah. This transmission capacity significantly enhances reliability not only for Utah, but the entire PacifiCorp East (PACE) system, improving the ability to move power in and out of Utah, particularly under certain outage conditions.

Grid reliability is also enhanced by the Energy Gateway South project connecting two separate diverse resource areas, Wyoming and Utah. Solar generation in Utah and wind generation in Wyoming, are both intermittent forms of renewable resources and Energy Gateway South provides a direct connection between the two areas enabling better operational control and improving grid reliability.

Combined with other transmission system improvements, past and future, the "backbone" of the Utah system has and will continue to be strengthened by the addition of Energy Gateway South and other transmission investments. Some of the more significant past investments that complement the Energy Gateway South project are:

Camp Williams – 90th South #3 and #4 345 kV lines
Mona – Oquirrh 345/500 kV line
Populus – Terminal 345 kV line
Sigurd – Red Butte #2 345 kV line
Oquirrh – Terminal #3 and #4 345 kV lines (future)

As part of the Energy Gateway South path rating technical studies, each of the projects noted above were included in the system model for Utah. These studies demonstrated that the facility additions and modifications necessary to support the Energy Gateway South project provided necessary support to the Utah area such that the performance of the Utah transmission system as well as other transmission systems in the Western Interconnection will meet all planning standards required by the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Corporation (NERC). Please refer to Attachment OPUC 158 which provides the Energy Gateway South Path Rating Study report.

The 2018-19 Northern Tier Transmission Group (NTTG) Regional Planning Report also demonstrated reliability benefits with Energy Gateway South. The NTTG report is publicly available and can be accessed by using the following website link:

https://nttg.biz/site/index.php?option=com_docman&view=list&slug=4-regional-transmission-plan-final&Itemid=31

OPUC Data Request 169

Please provide a narrative description of the Company's process for selecting indicator (dummy) variables for use in the forecasting models.

Response to OPUC Data Request 169

During the development of the forecast model for each state, the company analyzes the graph of the residuals in the model to make sure there are no outliers in the data that could influence the final model results. When outliers are identified, the company attempts to identify the source of the data anomaly. The source identification involves researching the individual customer billing data for the company's 1.9 million customers. If the source of the anomaly can be identified then the underlying data is corrected within the models input. If not, an indicator variable is used to prevent the anomaly from influencing the forecast.

LC 70 / PacifiCorp
February 20, 2020
OPUC Data Request 189

OPUC Data Request 189

Private Generation - Please refer to Staff's opening comments at pp. 20 – 22 where Staff identifies that the NREL dGEN model uses different assumptions for payback acceptance curves. Please explain whether the Company finds the payback acceptance curves in the underlying Navigant PG forecast are more appropriate than the NREL dGEN assumptions and why.

Response to OPUC Data Request 189

The 2019 National Renewable Energy Laboratory (NREL) study referenced in the question above uses a market penetration curve that is from an outdated 2008 Navigant report (https://www.nrel.gov/docs/fy08osti/42306.pdf, Figure 8). Navigant has refined this analysis over time and found that using the older curve was generally overestimating market behavior of private generation (PG) customers and required modification. Navigant believes that in order for the market adoption analysis included in the 2019 report to be consistent with actual observed adoption over time smoothing of the curves was needed. This addresses unrealistic "jumps" in the adoption results. The current Navigant analysis has a proven track record of accurately forecasting adoption of solar and other PG technologies in PacifiCorp's service territory as well as other utilities across the country.

LC 70 / PacifiCorp
February 20, 2020
OPUC Data Request 190

OPUC Data Request 190

Transmission - On Page 35 of PacifiCorp's reply comments, PacifiCorp states that "[a]ll 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." Regarding the NERC planning standards that PacifiCorp is referring to herein, please respond to the following:

(a) Please list the relevant NERC planning standards PacifiCorp is complying with through the Utah reinforcements.

(b) Please provide the NERC enforcement reference number that can be found on the NERC website for any WECC Compliance Exceptions, Spreadsheet Notice of Penalties, or Full Notice of Penalties for any enforcement exception or action against PacifiCorp in the past ten years for a NERC planning standard.

Response to OPUC Data Request 190

(a) In identifying system improvements, including those identified in Utah as part of the Energy Gateway South Project, PacifiCorp is required to meet North American Electricity Reliability Corporation (NERC) Planning Standards defined under TPL-001-4 and the corresponding Western Electric Coordinating Council (WECC) regional requirements TPL-001-WECC-CRT-3.2. Please refer to Attachment OPUC 190.

(b) PacifiCorp has incurred two instances of enforcement action with NERC Planning Standard TPL-002-0 in the past 10 years, found under the NERC enforcement reference numbers NP12-44-000 and NP14-35-000.

OPUC Data Request 191

Capacity Resources in Reserve - See 2019 IRP Volume 1, p. 611, where it states:

> "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."

(a) Please provide data for MW held in reserve under each of the two categories above in the years 2015, 2016, and 2017.

(b) Please provide the Company's definition of 'capacity held in reserve' for purposes of the 2019 IRP.

(c) Please explain the specific NERC or operational requirements that the capacity held in reserve intended to satisfy. Please specify in the Company's response whether these requirements are inclusive of or in addition to the Company's regulation, contingency, and other operating reserves.

Response to OPUC Data Request 191

(a) PacifiCorp has not performed the requested analysis.

(b) "Capacity held in reserve" is the excess capacity on dispatchable generation that is available on the system after scheduling to serve PacifiCorp load.

(c) "Capacity held in reserve" may be deployed to serve unexpected increases in load or to replace unexpected reductions in other generation resources. Depending on the capability of the resources in question, capacity held in reserve may also provide spinning reserve, non-spinning reserve, regulation reserve, and frequency response to maintain compliance with North American Electric Reliability Corporation (NERC) requirements, as discussed in PacifiCorp's 2019 Integrated Resource Plan (IRP), Volume II, Appendix F (Flexible Reserve Study).

LC 70 / PacifiCorp
February 20, 2020
OPUC Data Request 192

OPUC Data Request 192

Capacity Resources in Reserve - See 2019 IRP Volume 1 p. 611, where it states:

> "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."

Please specify the MW of capacity held in reserve, if any, that were also made available for upward dispatch by the Energy Imbalance Market.

Response to OPUC Data Request 192

PacifiCorp has not performed the requested analysis.

OPUC Data Request 193

Capacity Resources in Reserve - See 2019 IRP Volume 1 p. 611 where it states:

> "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."

Please list the specific resources in each category identified in the above quote that were held in reserve, by specific generator type and MW.

Response to OPUC Data Request 193

PacifiCorp has not performed analysis to identify, by generator type and megawatts (MW), capacity held in reserve incremental to the 13 percent planning reserve margin (PRM) for contingency, forecast error, and intra-hour volatility.

PacifiCorp does not designate, by generator type and MW, capacity held in reserve to mitigate risk during peak load conditions in the summer months.

Please refer to Confidential Attachment OPUC 193 which provides the reserve MW amount by hour, category and balancing authority area (BAA). The 241 MW summer peak load calculation supporting the uncertainty requirement is provided on the "241 MW" tab of the attachment. The 295 MW operational reserves calculation supporting the uncertainty requirement is provided on the "295 MW" tab of the attachment.

To clarify, the 295 MW of capacity held in reserve that is incremental to the 13 percent PRM is a calculated number that approximates the additional capacity needed in operations to cover the uncertainty and volatility related to net load forecasts as compared to net load actuals (where net load is defined as load less wind less solar). This calculation combines contingency reserve requirements (spin and non-spin), the forecast error from PacifiCorp's 2019 Integrated Resource Plan's (IRP) Flexible Reserve Study and the intra-hour load volatility from actual operations. The sum of these factors shows capacity above the 13 percent PRM and reflects current operational practice.

Confidential information is designated as Protected Information under Order No. 18-216 and may only be disclosed to qualified persons as defined in that order.

LC 70 / PacifiCorp
February 25, 2020
OPUC Data Request 206

OPUC Data Request 206

Transmission - Please provide a narrative explanation for PacifiCorp's reason for believing that it could be unable to renew its construction permit with BLM in 2027. What are the specific risks that could result in a failure to renew this permit?

Response to OPUC Data Request 206

The primary risk is the passage of time. This passage of time could result in a determination by the future United States (U.S.) Bureau of Land Management (BLM) authorized officer, in a future administration, that the data used in the original Environmental Impact Statement is stale and that a new analysis will be required. This new analysis could lead to the project not being authorized or changed to such a degree that it no longer meets PacifiCorp's purpose and need. As discussed in the company's response to OPUC Data Request 207, PacifiCorp's experience is that this could take as much as eight to 12 years.

LC 70 / PacifiCorp
February 25, 2020
OPUC Data Request 207

OPUC Data Request 207

Transmission - Please describe the process and a typical timeline for acquiring the necessary BLM permit to construct an interstate transmission line.

Response to OPUC Data Request 207

PacifiCorp has experience permitting two large interstate transmission lines, the 1,000 mile Energy Gateway West, and 440 mile Energy Gateway South projects. Both projects cross roughly 50 percent public land. As a result the United States (U.S.) Bureau of Land Management (BLM) acted as lead federal agency to comply with the Federal Land Policy and Management Act of 1976 and the National Environmental Policy Act (NEPA). The BLM does this by conducting an Environmental Impact Statement. This process took almost 12 years to complete for Energy Gateway West, and eight years for Energy Gateway South. The right of way grants issued by the BLM require a multitude of biological, cultural, and other resource preconstruction surveys which generally require two or three field seasons (years) to conduct. If anything unexpected is found, the BLM may require additional NEPA review prior to issuing a notice to proceed to construction.

LC 70 / PacifiCorp
February 25, 2020
OPUC Data Request 209

OPUC Data Request 209

> **Transmission -** Have there been any changes to relevant BLM regulations since the EGS permit was granted?

Response to OPUC Data Request 209

> No, there have not been any substantive changes to the Federal Land Policy and Management Act of 1976 or the National Environmental Policy Act since Energy Gateway South received the United States Bureau of Land Management right of way grant.

LC 70 / PacifiCorp
February 25, 2020
OPUC Data Request 210

OPUC Data Request 210

Transmission - Has PacifiCorp become aware of any information indicating that BLM would be likely to make substantial changes or deny renewal of the EGS construction permit?

Response to OPUC Data Request 210

No.

LC 70 / PacifiCorp
February 25, 2020
OPUC Data Request 211

OPUC Data Request 211

Transmission - Is PacifiCorp aware of any instances in which BLM approval for a permit renewal was denied? Please describe the details of any such circumstance.

Response to OPUC Data Request 211

No.

OPUC Data Request 212

Transmission - Please explain the reasons that PacifiCorp reduced the costs of Energy Gateway South (EGS) during the stakeholder input process leading up to the IRP.

(a) Please explain what new information was obtained that caused the cost update.

(b) Please also provide the total cost data from before and after PAC reduced EGS costs.

Response to OPUC Data Request 212

(a) Please refer to the company's response to OPUC Data Request 152.

(b) The original investment of Energy Gateway South transmission (stated in millions of dollars) was $1,868.4 at 100 percent, and $1,644.2 at 88 percent after wholesale transmission credits stated in 2019 dollars and growing at inflation. The 2019 Integrated Resource Plan (IRP) preferred portfolio updated investment for Energy Gateway South (stated in millions of dollars) was $1,752.8 million at 100 percent and $1,542.05 at 88 percent after wholesale transmission credits stated in 2024 dollars.