BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. LC 70

In the Matter of PACIFICORP, dba PACIFIC POWER, 2019 Integrated Resource Plan	Staff's Initial Comments

Contents

1. EXECUTIVE SUMMARY: STAFF'S REVIEW AND ANALYSIS OF PACIFICORP'S 2019 INTEGRATED RESOURCE PLAN

These opening comments focus largely on the questions and concerns that Staff would like addressed as we develop a recommendation for acknowledgement of the IRP. Staff's review of the 2019 IRP focuses on the accuracy and reasonableness of the IRP modeling inputs and assumptions, the methods used to select a preferred portfolio, and the specific items included in the 2019 Action Plan. Additionally, Staff assesses whether PacifiCorp's IRP has met the requirements of the Oregon IRP Guidelines, including identifying a resource portfolio that best balances cost and risks for ratepayers.[1] Below is a high-level overview of some of Staff's major topics of interest regarding PacifiCorp's 2019 IRP.

Load and Resource Balance

- The load and resource balance study is an important touchstone for evaluating how and when the preferred portfolio addresses future resource needs on PacifiCorp's system. Staff notes that the preferred portfolio includes several GW of new resources in 2023, yet the load resource balance study shows that the company does not have a strict need for new capacity until around 2028. Staff finds that, while the acquisition of resources in advance of need can potentially be part of a portfolio that best balances cost and risk under certain circumstances, the risks of such a strategy increase with each additional year the resources are moved ahead of a strict capacity need. Staff's initial comments discuss some of the risks of acquiring resources in advance of need, as well as Staff's concern that some of these risks are not fully included in PacifiCorp's portfolio modeling.

Transmission Selection

- Transmission investment decisions have comprised a major part of the 2019 PacifiCorp IRP and Action Plan. For the first time in the 2019 IRP, the capacity expansion software System Optimizer has been enabled to select some transmission investments as part of IRP portfolios. Staff's comments evaluate this development, including a discussion of the transmission assumptions in System Optimizer, and question how well the resulting portfolios reflect actual transmission needs and plans in the region.

Action Plan Specifics

- Staff has concerns and questions about the 2019 Action Plan, especially about the lack of specific details in the all-source Request for Proposals (RFP) action item and transmission action items. Staff makes recommendations for PacifiCorp to provide more detailed information about its action items and how they reflect the preferred portfolio, as required by IRP guidelines.

Supply Side Resource Cost Trends

- Operational and cost assumptions for new supply side resources influence the type and quantity of resources selected in IRP portfolios. Staff recommends development of low, medium, and high technology cost trend futures for consideration in IRP portfolio analysis.

[1] Order No. 07-047.

Energy Efficiency, Class 3 DSM

- Staff looks at the consistency with which energy efficiency is modeled between states and considers the potential for time-variable rates to contribute to meeting peak load in the action plan timeframe.

Demand Response

- While demand response resources appear to be a relatively low-cost way of meeting peak load, there is no demand response selected for Oregon in the action plan timeframe. In fact, very little demand response is assumed to be implemented in Oregon over the planning timeframe. Staff is concerned about this mismatch, and makes suggestions for pursuing cost-effective demand response.

Resource Adequacy and Reliability

- Regional resource adequacy studies have recently been showing the potential for capacity deficits in the region, and Staff's comments consider whether the findings of these studies are appropriately reflected in the IRP market availability assumptions.

2. PORTFOLIO DEVELOPMENT

In the 2017 PacifiCorp IRP, PacifiCorp agreed to perform a coal study assessing the economic impacts of near-term retirement of individual coal units.[2] Further analysis was then performed to identify potential savings associated with multiple coal unit retirements, concurrent with a stakeholder process guided by the Commission.[3] The coal analysis continued throughout much of the PacifiCorp IRP development public input process. Multiple stacked coal scenarios were considered, and additional reliability resources were added to coal study portfolios to create portfolios for the 2019 IRP.

PacifiCorp developed and compared dozens of resource portfolios in the 2019 IRP and evaluated each based on traditional cost and risk metrics reflecting the most likely range of costs to ratepayers. PacifiCorp's IRP analysis involved selecting coal retirement dates "by hand." This involved using the learnings from the coal study to select a series of coal unit retirements likely to result in customer savings, and using the capacity expansion model, System Optimizer (SO), to assess the expected costs of a portfolio based around those retirement dates.

PacifiCorp analyzed over 50 portfolios with hand-selected coal retirement dates in the 2019 IRP, and compared the Present Value Revenue Requirement (PVRR) cost and risk results of each portfolio to select a preferred portfolio. PacifiCorp has explained that this hand-selection method for evaluating the effects of different coal retirement dates was necessary because System Optimizer is unable to select optimal coal retirement dates endogenously in the same way it selects new capacity resources.[4]

[2] Docket No. LC 67. Order No. 18-138.
[3] Docket No. LC 70. Order No. 18-360.
[4] See PacifiCorp's response #3 to Sierra Club's October 15, 2018 Feedback Form, included in attachment A to these initial comments.

While there are many important economic assumptions included in IRP portfolio modeling, most are held constant from one portfolio to the next. In most 2019 IRP portfolios, coal retirement dates are the only input variable that changes between portfolios. Other inputs to the model include load forecast, market price forecast, available transmission, and assumptions about each potential new supply side and demand side resource. After PacifiCorp selects a set of coal retirement dates, the System Optimizer model uses a mathematical optimization process to select an optimized resource portfolio over the twenty year planning timeframe, given the planning assumptions provided.

After identifying seven top-performing portfolios (the "CP" portfolios in Chapter 7), PacifiCorp performed additional reliability studies on these seven portfolios, assessed the effects of potential future increases in market price volatility for five top portfolios, and assessed additional Energy Gateway transmission buildout scenarios for two top portfolios.

PacifiCorp identified portfolio P-45CP as the top performing portfolio. The preferred portfolio, P-45CNW, uses the same coal retirement schedule as P-45CP, but removes a substantial wind resource from the Dave Johnston site in 2027. This change will be discussed in Staff's comments in Section 5.2.

After selecting a preferred portfolio, PacifiCorp completed a series of sensitivity cases based on the preferred portfolio to assess how certain future conditions could impact the portfolio's resource buildout and cost. These sensitivity cases show the difference in total portfolio NPVRR from different modeling assumptions about future load growth, private generation, and customer preference resources. Each sensitivity requires a new portfolio run in System Optimizer, which selects new resources optimized around the new planning assumption. The table below summarizes the basic findings of these cases in terms of Net Present Value Revenue Requirement (NPVRR) cost or benefit:

Sensitivity Case	**(Benefit) / Cost Relative to P-45CNW ($ Million)**
S-01, Low Load Growth	($1,127)
S-02, High Load Growth	$1,139
S-03, 1-in-20 Load Growth[5]	$181
S-04, Low Private Generation	$101
S-05, High Private Generation	($238)
S-06, Business Plan	$831
S-07, No Customer Preference	($81)
S-08, High Customer Preference	($22)

Staff finds these sensitivities to be useful in understanding potential future implications of current planning decisions, but notes that the sensitivities would be more useful if they were performed on two or three top portfolios, in order to compare performance in those futures.

Staff finds that the coal study and IRP development process have identified potential savings for ratepayers through economic coal retirements. However, because optimal retirements could not be selected by the model endogenously, and there still remain retirement scenarios that have not been

[5] Assumes 1-in-20 extreme weather conditions during July.

fully assessed, Staff expects PacifiCorp will continue evaluating its planned coal retirement dates through further analysis in the next IRP cycle.

Recommendation:

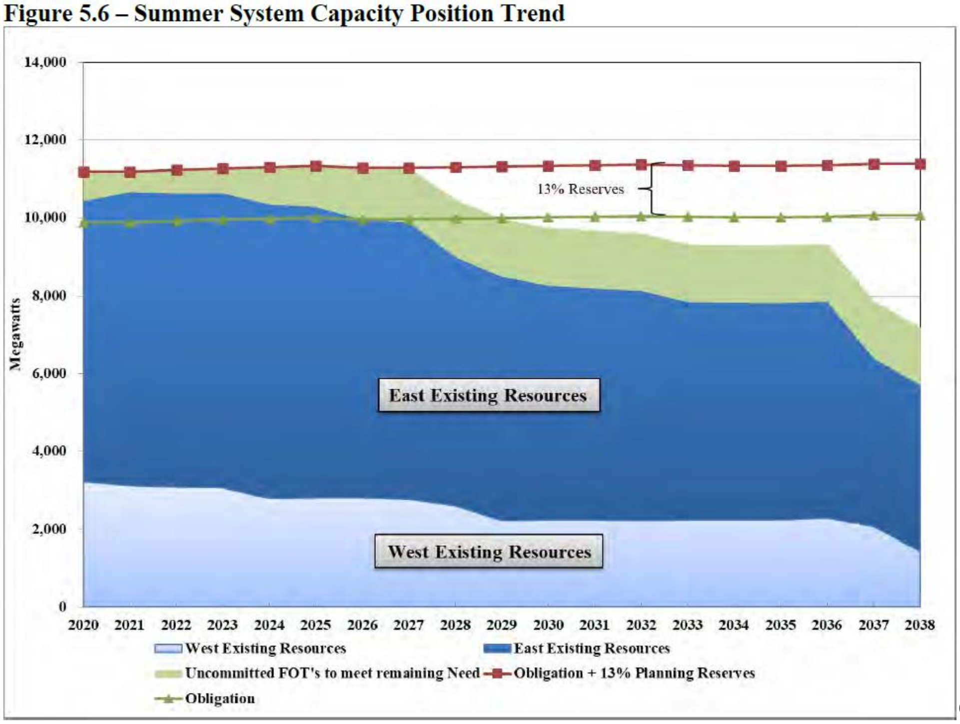
- **In the next IRP, PacifiCorp should perform sensitivities on two or three top-performing portfolios in order to compare performance in those futures.**

3. LOAD AND RESOURCE BALANCE, RESOURCE NEED

The load resource balance is one way of measuring whether the Company will need to acquire new resources in the planning timeframe. The load and resource balance table in Chapter 5 of the 2019 IRP compares the Company's forecast annual load obligations with the annual capability of PacifiCorp's existing resources, plus available market purchases, to meet peak load plus a planning reserve margin. The load and resource balance study in Chapter 5 shows that, without the addition of new resources, the company predicts a summer peak capacity deficit by 2028 and a winter peak capacity deficit by 2029.

Staff appreciates the information provided in Figures 5.6-5.9, which present seasonal and regional looks at the high-level load and resource balance at the summer and winter peaks. Figure 5.6 from the 2019 IRP is shown here for reference:

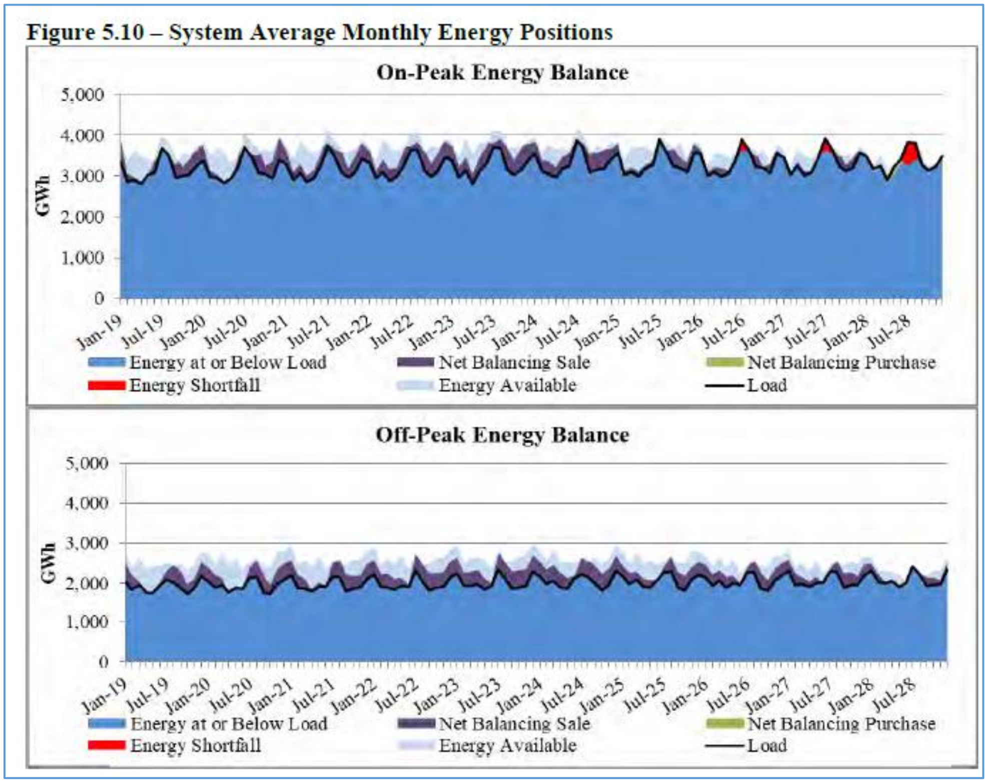
Figure 5.6 – Summer System Capacity Position Trend



[6]

[6] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 119.

The company presents energy position results as well in Figure 5.10:



The figures appear to show very low levels of market purchases, and Staff intends to review these results to better understand why market purchases are not more prominent.

Staff appreciates the informative load resource balance study and the inclusion of definitions for each component of the load resource balance. Staff has several questions, concerns, and suggestions about components of the study and their contributions to the load resource balance. The following sections will discuss forecasts and assumptions that influence the load and resource balance and the IRP portfolio analysis in the 2019 IRP.

3.1 EXISTING RESOURCES AND RETIREMENTS

Existing resources form the bulk of resources that will be used to meet load over the planning horizon, and the assumptions about the contributions of existing resources to meeting load are important to achieving optimal portfolios and an accurate load and resource balance study. Additionally, existing resource retirements contribute to the need for new resources. In some cases, retirements of older, more expensive units can lead to customer savings in the long-run, as in the case of certain economic coal unit retirements in the 2019 IRP.

Existing Resources

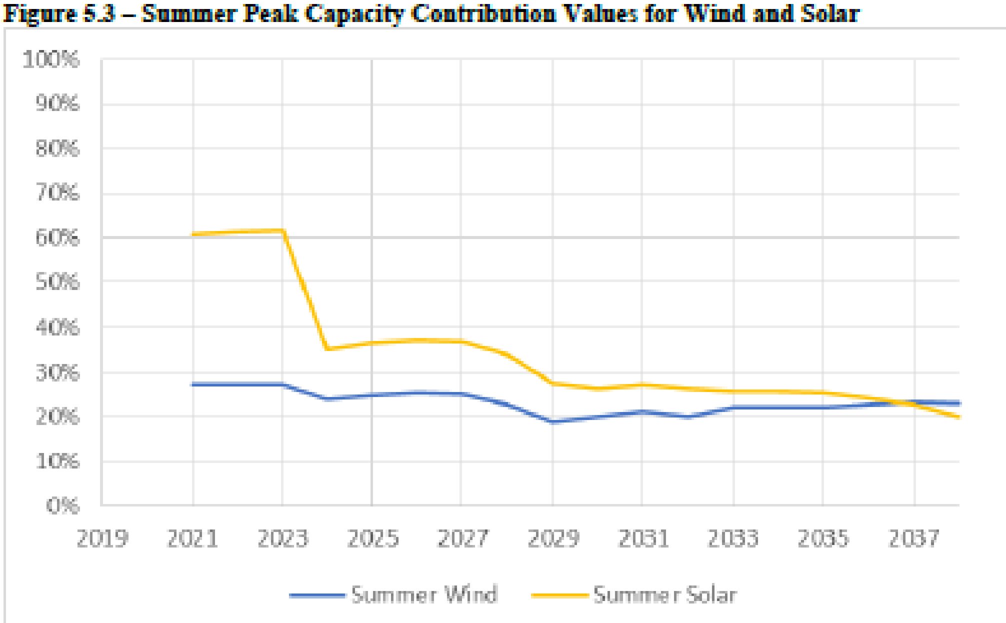
Existing resources include 8,459 MW nameplate capacity of thermal resources, 3,908 MW nameplate capacity of wind resources, and 1,759 MW nameplate capacity of solar. For demand-side resources, the company reports 507 MW of summer demand response, 177 MW of winter demand response, the persistent results of energy efficiency programs, 98 MW of time-based pricing, and an estimated “55-149 GWh” of inverted rate pricing. The contribution to meeting peak load, or ‘capacity contribution,’ of variable and demand-side resources requires a technical calculation, which Staff will continue to review.

Capacity Contribution

Staff notes that the available capacity contribution varies significantly by resource. For example, while the nameplate capacity for wind and solar resources totals 5,667 MW, the capacity contribution of “renewable” resources at the system peak in Tables 5.12 and 5.13 are 745 MW in summer and 1,614 MW in winter.

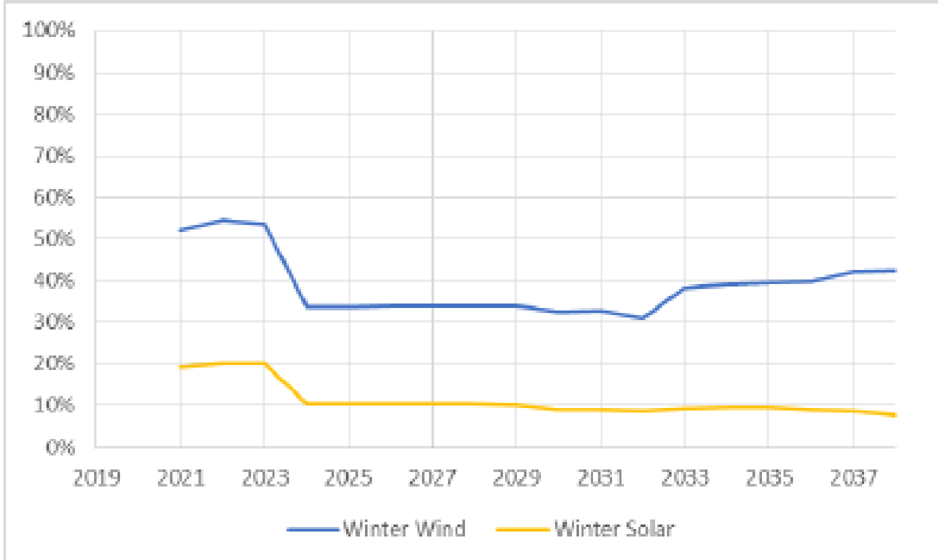
Staff is interested in the capacity contributions for existing wind and solar represented in Figure 5.3 and 5.4 in the 2019 IRP:

Figure 5.3 – Summer Peak Capacity Contribution Values for Wind and Solar



Note: Marginal benefits are lower than shown; refer to Volume II, Appendix N (Capacity Contribution Study).

Figure 5.4 – Winter Peak Capacity Contribution Values for Wind and Solar



Note: Marginal benefits are lower than shown; refer to Volume II, Appendix N (Capacity Contribution Study).

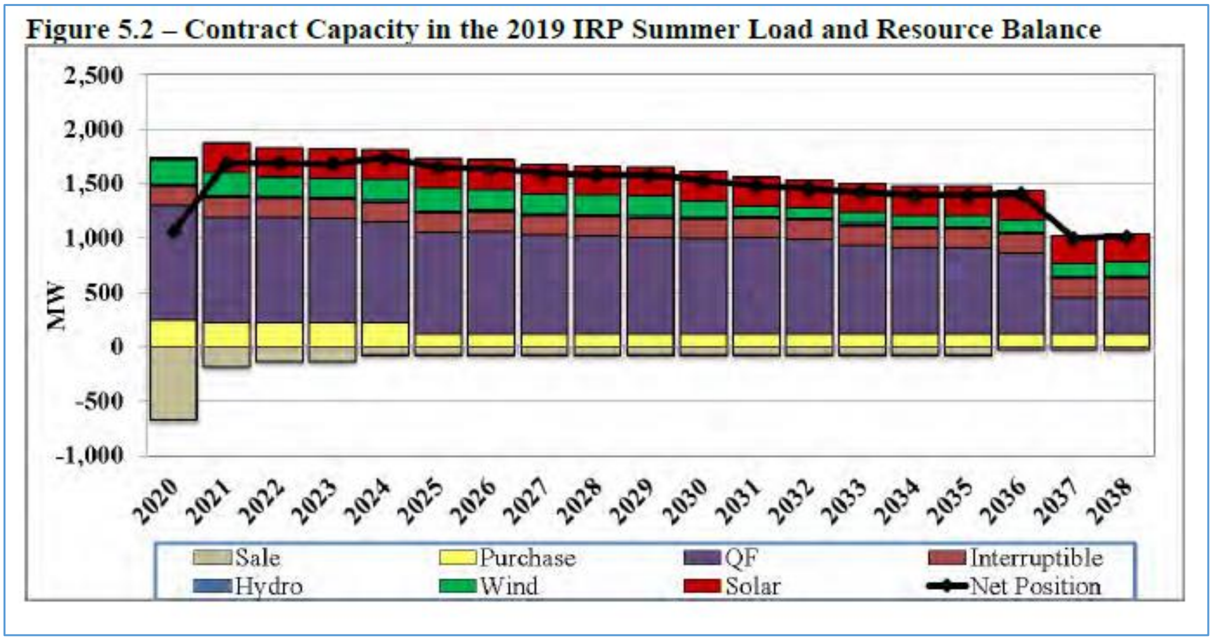
While Appendix N describes the methods used to derive the capacity contribution of wind and solar, Staff has remaining questions about the capacity contribution calculation and whether it is appropriate for inclusion in the load resource balance study. Specifically, Staff has questions about PacifiCorp's technique of calculating the capacity contribution of wind and solar by first calculating the contribution of all other resources in the portfolio, and then assuming that the remaining capacity in the load resource balance, including the 13 percent planning margin, is equal to the capacity contribution of wind and solar. [7]

Staff will be continuing to review the capacity contribution information in the 2019 IRP to understand if existing and new resources are handled with appropriate consistency, including demand-side resources.

Total Contract Capacity

The company provides the amount of summer contract capacity it has in place for 2020 through 2038, from power purchase contracts, including long-term firm contracts, short-term firm contracts, and spot market purchases, assuming that interruptible load contracts are extended:

[7] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 110.

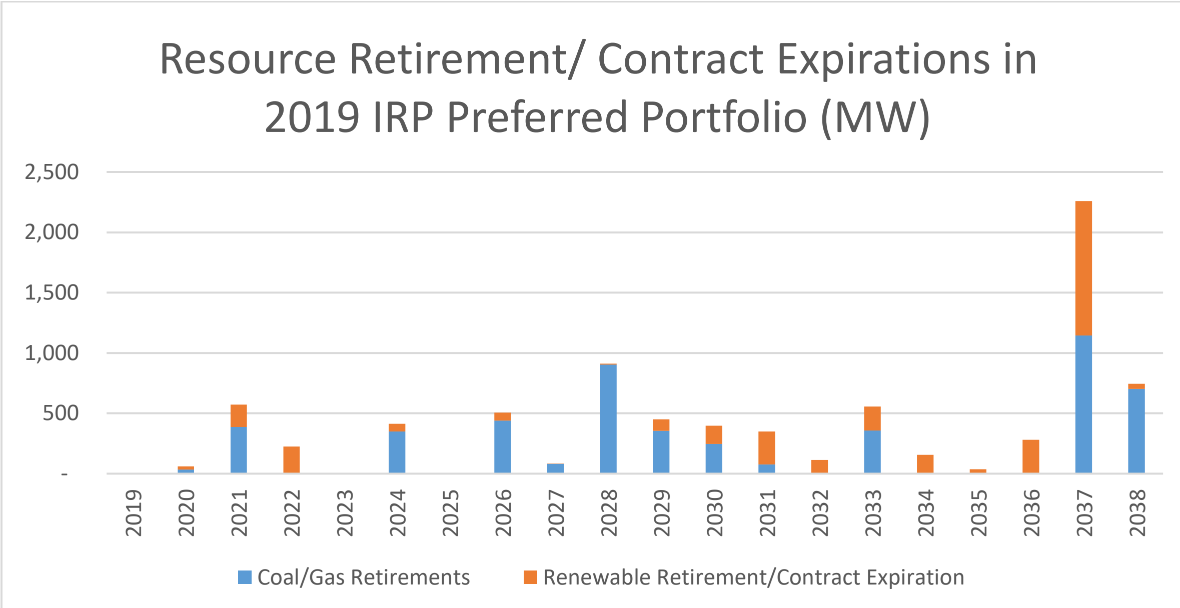


This graph indicates a reduction in sales contracts in 2021, along with an increase in solar contracts. There is also a drop-off in 2037 from expiring Qualifying Facility (QF) contracts. Staff is interested in reviewing PacifiCorp's assumptions about contracts and their contribution to peak capacity as part of the 2019 IRP review process.

Retirements

The 2019 IRP preferred portfolio includes retirement of 20 out of the Company's 24 coal units, or about 4,500 MW of capacity, by the end of the planning timeframe in 2038. About 600 MW of gas generation retires, and about 3,000 nameplate MW of wind and hydro resources retire or have contracts expire over the planning timeframe. The following chart represents the amount of resources that go offline in each year of the planning horizon in the preferred portfolio.

Figure 1 – Resource Ret Retirement/ Contract Expirations



Staff questions the assumptions the Company made about hydroelectric generation losses. In its 2019 IRP, the Company states that it will see 650,232 cumulative lost MWh of hydro generation by 2036.[8] The Company states that this assumption is based on the decommissioning of the Klamath hydro facilities, as well as relicensing of other projects that could lead to additional operating restrictions imposed in new licenses that could reduce available generation.[9] Staff has initiated discovery regarding the assumptions used in this calculation and will continue to explore this issue to determine whether PacifiCorp used accurate assumptions in its modeling.

3.2 FORECAST RESOURCES

Front Office Transaction (FOT) Availability

Front Office Transactions are a way to model the availability of contracts that are generally shorter-term, including spot market purchases as well as other market purchases and contracts of limited

[8] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 104.
[9] *Id*.

duration. As compared to the 2017 IRP, the 2019 IRP assumes 150 fewer MW are available from the market throughout the planning timeframe:

Table J.7 – Maximum Available Front Office Transactions by Market Hub

Market Hub/Proxy FOT Product Type	Availability Limit (MW)			
	2019		2017	
	Summer (July)	Winter (December)	Summer (July)	Winter (December)
Mid-Columbia (Mid-C)				
Flat Annual or Heavy Load Hour	400	400	No Change	
Heavy Load Hour	375	375	No Change	
California Oregon Border (COB)				
Flat Annual or Heavy Load Hour	250	250	Reduced to 250 from 400	
Nevada Oregon Border (NOB)				
Heavy Load Hour	100	100	No Change	
Mona				
Heavy Load Hour	300	300	No Change	
Total	**1,425**	**1,425**	**1,575**	**1,575**

[10]

This assumption is significant because it reduces the amount of market resources the Company will rely on before planning to acquire a new resource. Staff is aware of and is continuing to consider the various reports forecasting regional capacity deficits if new resources are not planned and built. These include studies by WECC, PNUCC, E3, NWPCC, and BPA. Staff will take these studies into account when assessing whether PacifiCorp's FOT availability assumptions are appropriate.

QF Forecast

PacifiCorp's IRP does not include a forecast of new QF contracts the Company expects will be signed over the 20 year planning horizon.[11] Effectively, this is equivalent to an assumption that no new QF contracts will be signed in the next 20 years. Staff's position is that a forecast of zero new QFs is unreasonable and that uncertainty about the number of new QF contracts is not a reason for a forecast of zero new QFs. For context, there is currently about 2 GW of nameplate QF capacity connected to PacifiCorp's system. Staff plans to investigate and consider how queue reform may impact the number of QFs able to interconnect to PacifiCorp's system in the future.

Staff notes that the upcoming QF investigation, UM 2038, will look into issues of QF assumptions in long term planning. While the UM 2038 investigation may come to a different answer for modeling QFs in future long term planning, Staff recommends that for the 2019 IRP, the preferred portfolio should be updated using a QF forecast based on historical averages reflecting those contracts that reach commercial operation, segmented by project size in MW.

[10] PacifiCorp 2019 Integrated Resource Plan. Volume II. Appendix J. Page 155.

[11] See PacifiCorp's response to REC DR 3, included in attachment A to these initial comments.

Recommendation:

- **PacifiCorp should update the Preferred Portfolio with a forecast of new QF capacity that reflects historical trends.**

3.3 LOAD FORECAST

LOAD FORECAST METHODOLOGY

Overall, PacifiCorp's econometric models utilize industry best practices common throughout the region. Auto Regressive Integrated Moving Average (ARIMA) models are used to handle time-series forecasts that include common forecast drivers like weather, population, and economic metrics. Further, the Company uses data sources and modeling software from respected third-party firms, including Itron for the software and modeling and IHS Markit for the economic and demographic data. The process of breaking down residential demand into a customer count forecast and use-per-customer forecast, as well as considering the Company's largest industrial customers individually based on information obtained from the customer are also industry standard practices. The methodology further appears to be econometrically sound. Proper caution has been taken to avoid particular pitfalls which can arise, including non-stationarity and serial correlation, which violate the standard regression assumptions and can bias standard errors or forecasts. Staff does have several concerns following its initial review of the forecast. Staff also applauds the Company's examination of its normal weather assumption in light of ongoing changes to the climate.

Transparency and Replicability

In reviewing a Utility's forecast, Staff traditionally will replicate the Company's model in order to fully understand the methodology and look for potential improvements. While this is possible using the provided regression coefficient output, the underlying data, and some trial-and-error, the actual model specification is generally a much simpler place to start. First, it can provide a general understanding of the model at a glance. Second, it ensures that Staff's replicated model captures every nuance that the Company might have built into the model. All other regulated utilities under the Commission's jurisdiction provide Staff and any qualifying intervenors access to the model equations, generally upon request. However, PacifiCorp declined to provide this information, stating that "all modeling is performed internal to the Metrix ND software, the source code is proprietary to ITRON."[12] This is not a standard utility practice, while the information provided in the Company's workpapers can be used to closely approximate the equations, it is done at the unnecessary cost of additional time. If such modeling is used in any future RFP, PacifiCorp will be required to provide the Commission, the independent evaluator, and any non-bidding interested parties with access to the equations.[13] Staff intends to ask the Company what steps it has taken to authorize Staff's access to this information.

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[12] See PacifiCorp's response to Staff DR 37, included in Attachment A to these initial comments.

[13] OAR 860-089-0400(6).

Staff further has concerns regarding the Company's use of the Company's Statistically Adjusted End-Use (SAE) methodology. The data generating process and methodology are not transparent and the end-result on the forecast is not clearly specified.

Finally, Staff found the methodology description as it relates to weather lacking in transparency. As the single-largest driver of electricity demand, the proper selection of weather stations, data transformation, and weather assumptions can have large impacts on the final forecast.

Staff's concern is that PacifiCorp did not provide any party interested in examining its load forecast with enough detail and information to make an easily informed opinion. Staff recommends that the Company review its decision to deny requests for model equations, take any necessary steps to provide access, and include more narrative explanations regarding its SAE and weather related modeling.

Recommendation:

- **Staff recommends that the Company attempt to provide more transparency and information in future IRP filings while maintaining the Company's business interests.**

Customer Count Changes

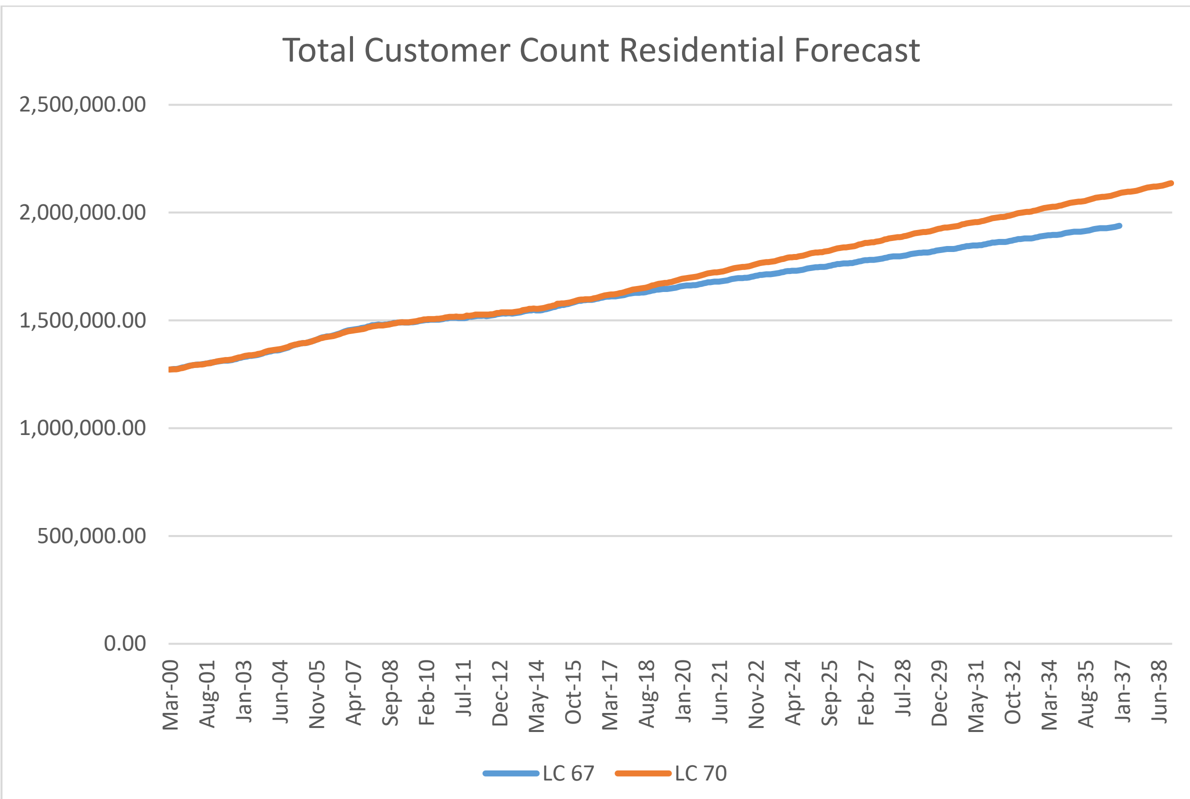
The residential customer count forecast changed from a model which predicted the number of customers to a model which predicted the change in the number of customers from year to year. This 'differencing' of the data is common in ARIMA models, normally done to handle non-stationarity issues, which can be present in time-series data. However, PacifiCorp noted on page 13 of Appendix A that the methodology change was made in order to produce a more accurate forecast. PacifiCorp further noted that it "performed a historical comparison of the forecasted results using both methods against actual customer counts and determined the differenced model produced a more accurate customer forecast." In reviewing the change however, Staff did not find that the new model produced more accurate forecasts when compared to historical data. Staff converted the differenced data back to gross amounts and calculated the mean absolute percentage error (MAPE) for the LC 70 and LC 67 models and found that on the differenced LC 70 model had a MAPE which was on average over eight times larger than the LC 67 model.

Table 1 - Mean Absolute Percentage Error Comparison

	LC 70 MAPE	LC 67 MAPE	Percentage Difference	Gross Difference
California	0.49%	0.06%	867%	0.43%
Idaho	0.51%	0.07%	721%	0.44%
Oregon	0.16%	0.04%	378%	0.12%
Utah	0.47%	0.05%	927%	0.42%
Washington	0.66%	0.06%	1195%	0.61%
Wyoming East	0.25%	0.04%	557%	0.20%
Wyoming West	1.35%	0.13%	1051%	1.22%
Average			814%	0.49%

Staff notes that all of the MAPEs were small, with the highest being below 1.35 percent. This means that on average, the models all predicted an annual customer count forecast within 1.35 percent of the actual value for the year. However, the model errors will almost always grow larger as the forecast horizon is extended, so a small error in 2018 can easily turn into a larger error in 2036. To illustrate this, Staff provides two figures below. The first shows the difference in the total customer count between the two IRPs. The second displays the average MAPE for each LC 67 forecast between March 2016 and February 2018.

Figure 2 – Customer Count Residential Forecast



Staff notes, that the “in-sample” forecasts are nearly identical; however, this period displayed a clear advantage in forecast ability in the LC 67 model. When looking at the “out-of-sample” forecast, the difference is noticeable. This shows that as the forecast horizon extends, the differences between the two models and their relative accuracy will become more important. Further, not only do the actual forecasts deviate, but very likely the forecast errors will as well.

Figure 3 – Out-of-Sample MAPE

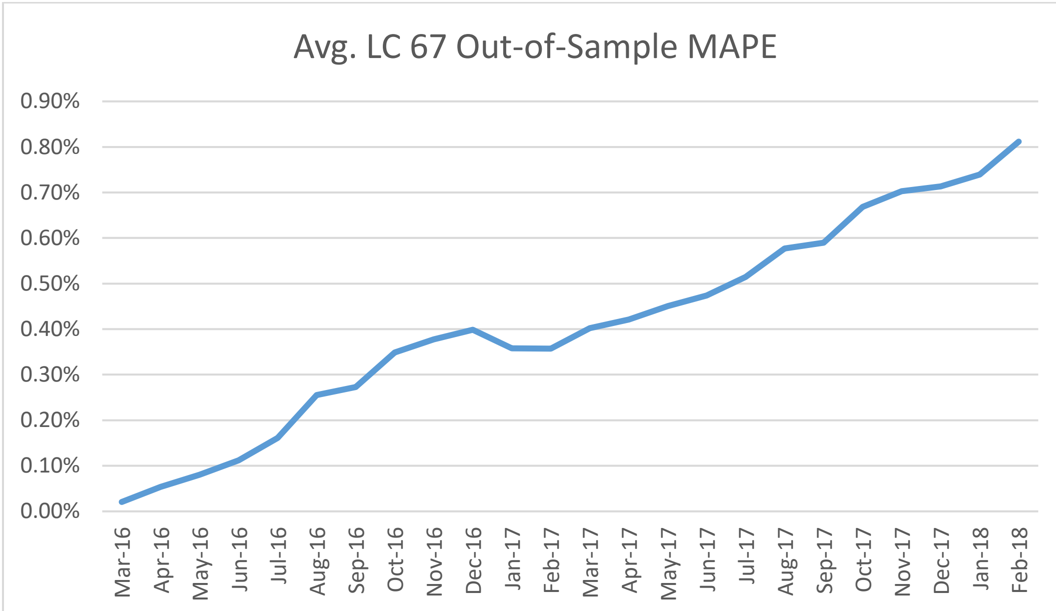


Figure 3, above, provides the average MAPE for the LC 67 forecasts during the interim period between the two IRP's.[14] Staff notes that the error grows nearly monotonically as the forecast extends. If this trend were to continue to the end of the forecast horizon for this IRP, this would equate to a roughly eight percent forecast error for December 2038, or about 140,161 MWh in the single month. Given that the non-differenced model was more accurate in all states, Staff would expect the forecast error to be even larger for the LC 70 model in 2038. Because the Company did not make the change to deal with non-stationarity, Staff does not understand the reason for the change.

Staff notes that the model change has had what appears to be rather large implications for the final forecast. For example, the Utah customer count forecast increased by over seven percent in December 2036 when comparing the LC 70 and LC 67 forecasts. However, the main driver of the forecast, the IHS population forecast, decreased by over 4.5 percent in 2036 from the 2017 forecast to the 2018 forecast.[15, 16]

Recommendation:

- **Staff recommends that the Company provide further insight into the metric used to determine an improvement in load forecast accuracy.**

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[14] Staff used actual data from LC 70 to calculate the forecast error for LC 67.

[15] Staff extrapolated the IHS Markit data from 2028 to 2036 using a linear trend line to identify the percentage change at the end of the IRP forecast horizon.

[16] Staff notes that it found a potential data error in a dummy variable for a particular month which may be affecting the model output. Staff will follow-up with the Company regarding this issue.

The Use of Indicator Variables

A large number of PacifiCorp's forecasts include the use of indicator variables which are included to presumably handle outlying values. This is not an uncommon practice in regression modeling. However, care must be taken when identifying and selecting these variables as the model will omit the effect of that particular data point in the forecast. As mentioned in the footnote below, PacifiCorp elected to include an indicator variable for a particular month and year which had a change in customer accounts, which was unusual compared to the rest of the data. This decision can help to create a more normalized forecast. However, the model will effectively disregard this information in its forecast because the forecast horizon beyond the sample will not include another May 2015 or December 2011 when it is forecasting from 2019-2038. It is imperative that the forecaster research the cause of the data abnormality in order to determine if the circumstances warrant the use of an indicator variable.

Recommendation:

- **Staff recommends that the Company attempt to identify and document the source of the data abnormality whenever utilizing indicator variables in a regression.**

CAPACITY FORECAST

The Company forecasts a coincident system peak that grows from 10,284 MW in 2019 to 12,193 in 2038 with a base growth rate of 0.9 percent before applying demand-side resources such as energy efficiency and private generation. Compared to the peak capacity forecast in the 2017 IRP, there is almost no change in forecast summer peak MW through 2026.[17]

Table 5.1 – Forecasted System Summer Coincident Peak Load in Megawatts, Before Energy Efficiency and Private Generation (MW)

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System	10,284	10,425	10,549	10,671	10,788	10,934	11,012	11,057	11,149	11,261
	2029	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
System	11,362	11,469	11,575	11,696	11,809	11,723	11,834	11,946	12,078	12,193

[18]

Because accurately forecasting peak demand is critical for resource selection, Staff will continue to assess this forecast and compare PacifiCorp's specification with alternative model choices.

TRANSPORTATION ELECTRIFICATION

Staff appreciates the summary of the Company's efforts to promote transportation electrification across its multistate territory. However, the 2019 IRP does not appear to include a separate forecast of the

[17] PacifiCorp 2017 Integrated Resource Plan. Volume I. Page 76.
[18] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 98.

effect electric vehicle adoption will have on PacifiCorp's load. The 2019 IRP goes on to say: "Electric vehicle load is; however, reflected in the Company's load forecast."[19]

Recommendation:

- **In PacifiCorp's reply comments, Staff would like a detailed explanation of how future load from transportation electrification is captured in the Company's load forecast. What is PacifiCorp's expectation of high, medium, and low EV load growth across its multistate territory, and how are these scenarios reflected in the Company's analysis of PacifiCorp's resource need?**

PRIVATE GENERATION

In the 2019 IRP, PAC forecasts the adoption of private generation (PG) over the planning horizon and applies these resources as an offset (reduction) to the load forecast. PAC contracted with Navigant to update its 2016 PG forecast, consisting of base, high, and low scenarios for customer-sited solar photovoltaic (PV), small-scale wind, small-scale hydro, and combined heat and power (CHP). This analysis indicates that customer sited resources will have a material impact on the Company's forecasted summer load, starting at two percent in the Action Plan Window and increasing to six percent over the course of the planning horizon. At the same time, the winter impact is negligible.

Table 2 - Private Generation in the Load Resource Balance[20]

	2025 Action Plan Window		2038 IRP Planning Horizon	
	Summer	Winter	Summer	Winter
Private Generation - East + West	227 MW	4 MW	674 MW	28 MW
Load* - East + West	11,012 MW	9,497 MW	12,192 MW	10,398 MW
Ratio of Private Generation to Load	2%	0%	6%	0%

*Load includes all load before PG, Energy Efficiency, and interruptible loads are decremented.

While the impact remains meaningful, the 2019 PG forecast reflects lower adoption than the previous IRP. As PAC explains:

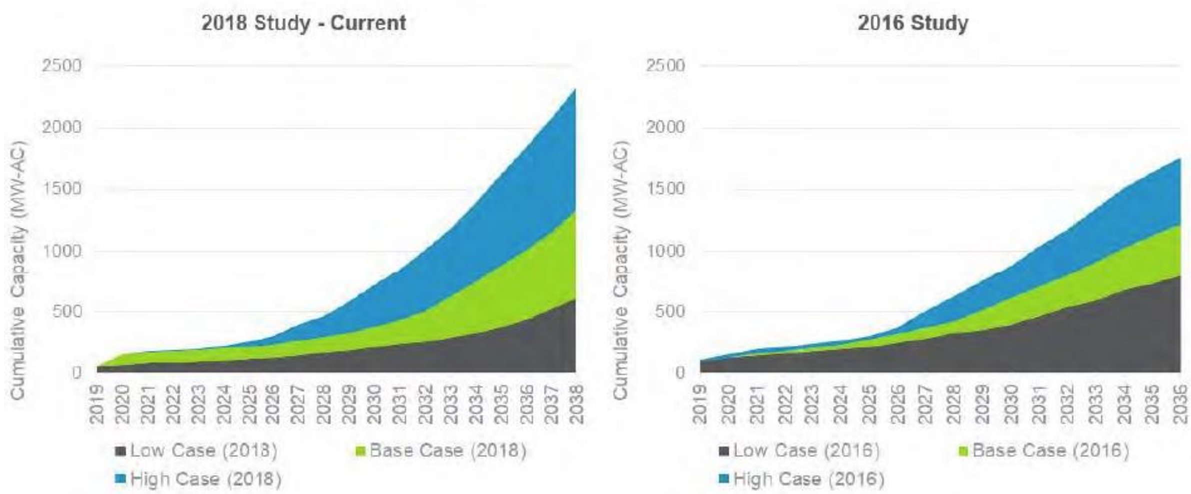
> "[i]n the short-term, factors impacting adoption have a dampening effect on the market, yet more aggressive reduction in solar PV system costs longer-term, result in increased adoption over time. In 2036, the latest year in both studies, cumulative adoption in the base case is around 1,000 MW in the 2018 study and around 1,200 MW in the 2016 study."[21]

Based on these factors, Staff is in the process of reviewing the assumptions and methodology underlying the forecast. Staff seeks to ensure that the current PG forecast is not understating the adoption of PG

[19] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 62.
[20] PacifiCorp 2019 Integrated Resource Plan. Volume I. Pages 115 – 118.
[21] PacifiCorp 2019 Integrated Resource Plan. Volume II. Appendix O. Page 6.

technology over the planning horizon and to confirm whether it is reasonable to assume that PG adoption will be lower than forecast in the previous IRP, particularly in the near term.[22]

Figure 4 - Comparison of Current and Previous IRP PG Forecasts[23]



Adoption Curves

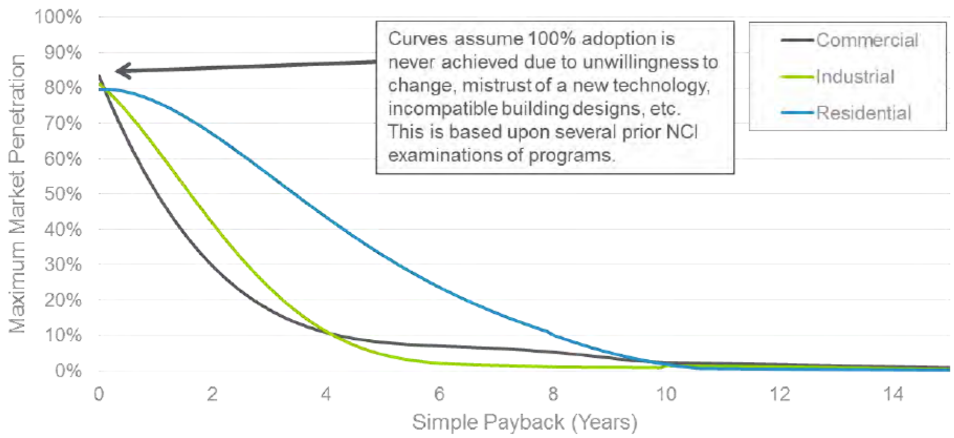
The Navigant study underlying the PG forecast uses a payback analysis and Fisher-Pry diffusion curves to determine likely market penetration for PG technologies from 2019 to 2038. The adoption model considers a range of factors that impact market penetration such as technical potential, technology maturity and costs; net metering policies and rate design and the range of incentives available at the time of the study. Staff finds that this approach is generally robust, but questions whether the assumptions related to payback period are understating the potential market penetration.

For example, the Navigant study utilizes the following payback acceptance curves to inform assumptions about the rate and timing of PG technology adoption in PAC's service area:

[22] *Id.*

[23] PacifiCorp 2019 Integrated Resource Plan. Volume II. Appendix O. Page 6.

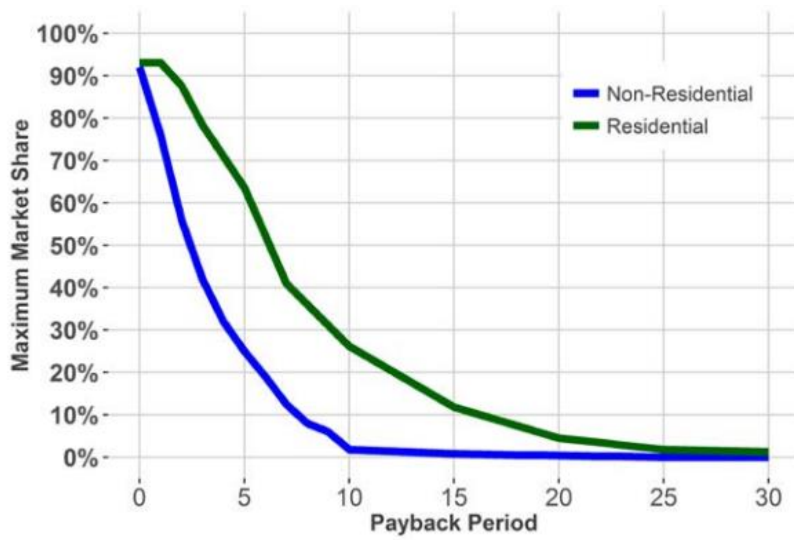
Figure 5 - Navigant PG Study Payback Acceptance Curves[24]



Source: Navigant Consulting based upon work for various utilities, federal government organizations, and state/local organizations. The curves were developed from customer surveys, mining of historical program data, and industry interviews.

These assumptions appear more conservative than those used by other PG forecasts. For example, the Navigant study assumes an 80 percent maximum market penetration and almost no commercial adoption beyond a four year payback period. However, NREL's dGEN model assumes a 90 percent maximum market share with non-residential adoption well above the Navigant assumptions up to 10 years.

Figure 6 - NREL Market Potential as a Function of Payback Period[25]



[24] PacifiCorp 2019 Integrated Resource Plan. Volume II. Appendix O. Page 10.

[25] Kwasnik, Ted, Benjamin Sigrin, and David Bielen. 2019. Quantifying Resolution Implications for Agent-based Distributed Energy Resource Customer Adoption Models. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-72267. https://www.nrel.gov/docs/fy19osti/72267.pdf.

Staff will continue evaluating the customer adoption assumptions underlying PAC's PG assessment and provide further comment if the base forecast appears to be understating potential adoption of PG over the planning horizon.

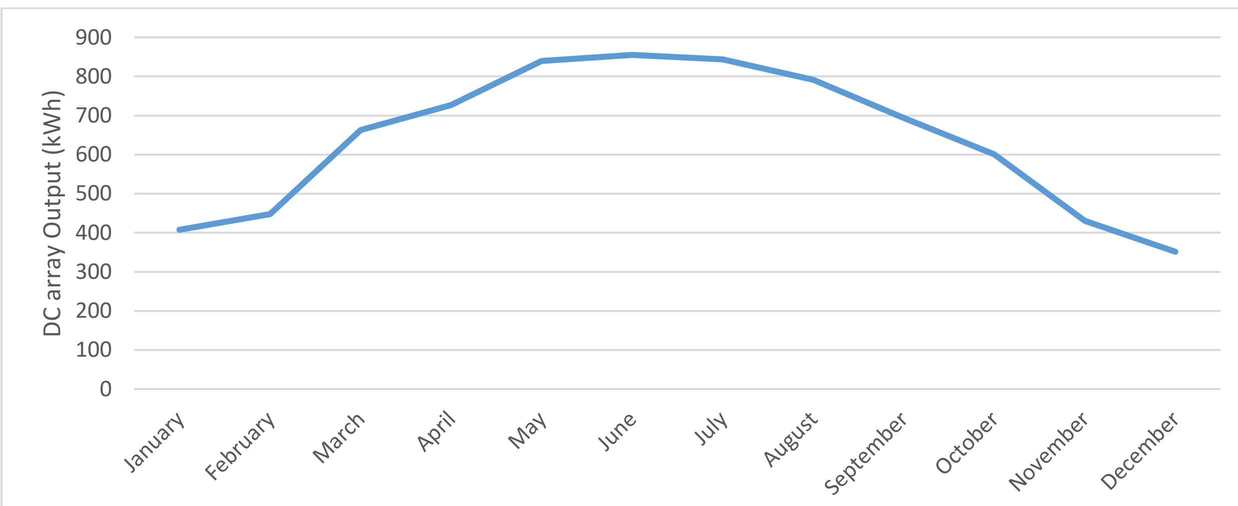
Recommendation:

- **Staff recommends PacifiCorp explain how its market penetration models are reflecting the potential for PG adoption over the 2019 IRP planning horizon.**

Winter Contribution

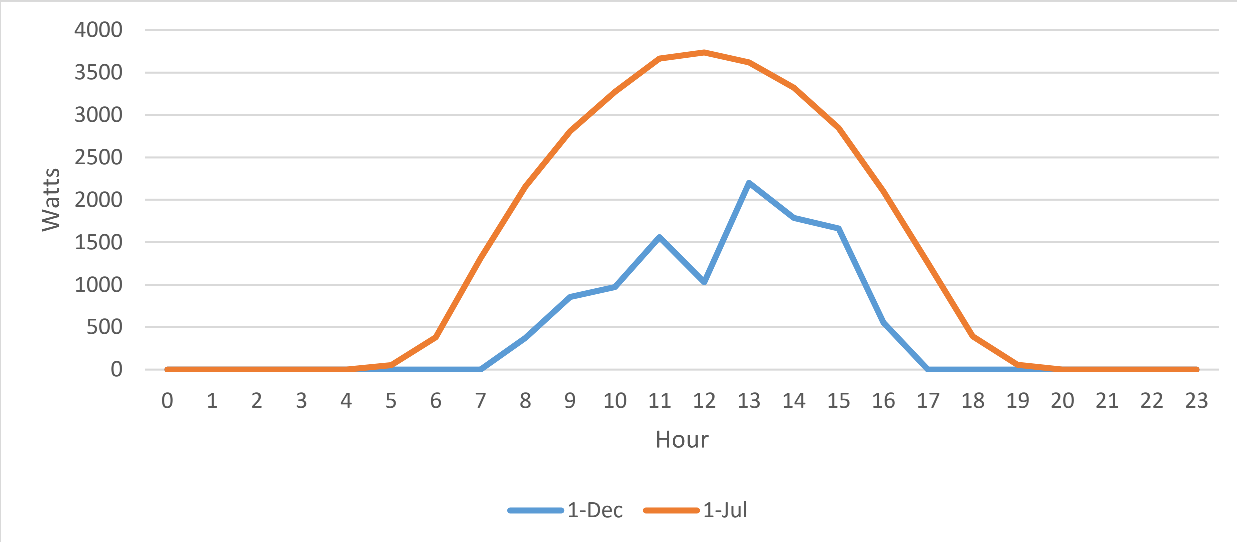
Staff is also investigating the Company's assumptions related to PG resource performance in the winter. In the load-resource balance, PAC indicates that the winter contribution of Private Generation in 2025 is 3 MW in the East and 1 MW in the West, as compared to a summer contribution of 188 MW and 39 MW respectively.[26] As illustrated in Figure 7 and Figure 8, distributed solar resource generation is typically lower in the winter; however, this level of seasonal variation is likely not at a scale of 3:188 when considered monthly or hourly. Staff will continue to investigate the underlying analysis to determine if the PG forecast is understating the winter contribution of these resources.

Figure 7 - PV Watts Monthly Output for a 5 kWdc Solar Shape in Salt Lake City, UT[27]



[26] PacifiCorp 2019 Integrated Resource Plan, Volume I. Pages 115 – 118.
[27] NREL's PVWatts energy estimate is based on an hourly performance simulation using a typical-year weather file that represents a multi-year historical period for Salt Lake City, UT for a Fixed (open rack) photovoltaic system. The kWh range is based on analysis of a nearby data site.

Figure 8 - PV Watts Hourly Output for a 5 kWdc Solar Shape in Salt Lake City, UT[t28]



Policy Drivers

While the Navigant study lacks detail on the federal and state incentives that are assumed in the base, high, and low PG forecasts, Staff's understanding is that all three forecasts assume that PG incentives sunset in line with the 2018 policy landscape without being renewed or replaced.[29]

Staff notes that the lack of certainty about new policies is not necessarily a reason for a zero forecast. For example, the 2019 IRP assumes that the Residential Energy Tax Credit (RETC) sunset in 2017.[30] While this sunset occurred, Oregon House Bill (HB) 2618 created a new solar and solar plus storage rebate program in 2019, which may counteract some of the market dampening effect associated with the RETC sunset. This new policy provides a relatively small incentive compared to policies such as the expiring federal investment tax credit (ITC) for residential systems. However, the policy evolution experienced within one year suggest that the PG forecast may be understating the impact of ongoing policy development on long-term PG adoption.

Recommendation:

- **Staff recommends PacifiCorp should demonstrate whether policy drivers have been appropriately considered in the Navigant PG study. If they have not been appropriately considered, then PacifiCorp should re-assess a few top portfolios using the high Navigant private generation forecast, since a lack of policy driver assumptions in the Navigant study would bias the estimates downward.**

[28] Id.
[29] Based on discussion and information provided an the August 30, 2018 IRP Public Input Meeting.
[30] PacifiCorp 2019 Integrated Resource Plan. Volume I. page 5.

CUSTOMER STORAGE

Staff is interested in understanding why the PG forecast does not account for adoption of collocated solar and storage or standalone distributed storage systems. Nationally, adoption of behind the meter storage systems has increased steadily and is anticipated to continue to grow over the PAC IRP action plan window.[31,32,33] In addition, research indicates that commercial customers with monthly demand charges in excess of $9-$15/kW are an indicator of favorable behind the meter storage markets—which captures the demand charge for Utah's large customer rate schedule.[34]

While behind the meter storage systems are not net generators, these systems could impact the PG forecast's contribution to peak. This consideration may be directly relevant to Staff's questions about winter PG contribution above. Therefore, Staff requests that PAC's reply comments explain whether the impact of behind-the-meter storage is adequately addressed in the 2019 IRP.

Recommendation:

- **Staff recommends PacifiCorp explain how it's considering distributed storage technologies in the 2019 IRP.**

Conclusion

In summary, Staff believes that the Company's forecast methodology is generally sound and should produce a relatively unbiased forecast. The peak capacity forecast is substantially the same as that from the Company's 2016 IRP. Staff will continue its review of the model and complete its reproduction of the methodology. Further, Staff believes that the Company could provide more detailed information in order to aid interested parties in the review of its forecast.

4. ECONOMIC OPPORTUNITY

The extent to which utilities should acquire new resources in response to an economic opportunity to potentially lower costs for ratepayers, even if an actual energy or capacity need is not immediate is a topic the Commission has considered in recent IRPs, dockets LC 66 and LC 67.[35] In LC 67, the Commission stated, "Although we do not definitively resolve questions surrounding need, it should be apparent that when a utility does not need to take action within the action plan window to address regulatory

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[31] Wood Mackenzie Power & Renewables/U.S. Energy Storage Association U.S. energy storage monitor Q4 2019 executive summary, December 2019, https://www.woodmac.com/research/products/power-and-renewables/us-energy-storage-monitor/.

[32] National Renewable Energy Laboratory, Identifying Potential Markets for Behind-the-Meter Battery Energy Storage: A Survey of U.S. Demand Charges, August 2017, https://www.nrel.gov/docs/fy17osti/68963.pdf.

[33] Bloomberg, Residential Energy Storage Market Worth $17.5 Billion by 2024 - Exclusive Report by MarketsandMarkets, May 1, 2019, https://www.bloomberg.com/press-releases/2019-05-01/residential-energy-storage-market-worth-17-5-billion-by-2024-exclusive-report-by-marketsandmarkets.

[34] See Rocky Mountain Power Utah Schedule No. 08.

[35] See LC 66, Order No. 17-386; LC 67 Order No. 18-138.

compliance or reliability needs in the near-term, we will pay significantly more attention to near-term impacts and longer-term costs risks. . . .We reaffirm our commitment to the fundamentals of our IRP precedent, identifying a preferred portfolio that is a least-cost, least-risk portfolio of resources to meet customer capacity and energy needs."[36]

While reducing costs for customers is one of the main goals of long term planning, acquiring resources in advance of need can be risky. Making large, irreversible decisions to acquire resources carries with it the risk that economic variables may change in unexpected ways in the future, reducing or reversing the expected benefits of the acquisition. Because predicting future economic conditions is more difficult in the long term, the risk increases with acquisitions made farther in advance of need. Acquiring resources in advance of need also raises questions of intergenerational equity, because customers pay for the resources in advance of when they are needed and those customers may not be the same ones who enjoy benefits of the early acquisition in the future.

4.1 PRODUCTION TAX CREDIT EXPIRATION

Production tax credit (PTC) expiration is one factor that has created potential economic opportunities associated with building new wind plants and transmission before the PTC expiration rather than after. This holds true even though the new resources are not strictly needed until after the PTC expiration. In the 2019 IRP, PTC wind projects are a substantial driver of resource acquisitions in the action plan timeframe, including the Energy Gateway South transmission project and associated Wyoming wind. Staff is continuing to work on assessing and quantifying the risks of acquiring resources in advance of need, including those risks that have not been modeled in PacifiCorp's IRP portfolios. For example, one risk is that PTCs do not expire when they are scheduled to expire. In that case, the Company would have been better off waiting to acquire resources in a later year. The very recent extension of the PTC in 2019 illustrates this point.

On December 20, 2019, the federal Further Consolidated Appropriations Act, 2020 was signed into law.[37] Section 127(c) extends the Production Tax Credit by one year, extending eligibility to wind facilities that begin construction in 2020 and come online by 2024. In addition, the value of the PTC returns to 60 percent of the PTC, instead of the 40 percent eligible to facilities that begin construction in 2019 and come online by end of 2023.

[36] Docket LC 67, Order No. 18-138.

[37] Federal H.R.1865.

Table 3 - Product Tax Credit Eligibility

Construction start year	Construction end year	PTC amount
2016	2020	100%
2017	2021	80%
2018	2022	60%
2019	2023	40%
2020	2024	60%

The 2019 IRP assumes wind resources added after 2023 are ineligible for the PTC. Consequently, the preferred portfolio selects nearly 2 GW of wind resources by 2023 and does not add wind resources again until 2028.[38,39] Therefore, more analysis is required to understand whether the timing and design of the RFP action item remains least cost, least risk under these new circumstances.

In addition, the Supply Side Resource Tables suggest that the Company modeled proxy wind resources with a 100 percent PTC and 40 percent PTC, but not 60 percent PTC.[40] This omission, though not intended, would negatively impact the quality of portfolio modeling. To confirm that there are not omissions in modeling federal incentive eligible resources, Staff also requests that PAC discuss how PTCs and investment tax credits (ITCs) under current law are modeled in the IRP in its reply comments.

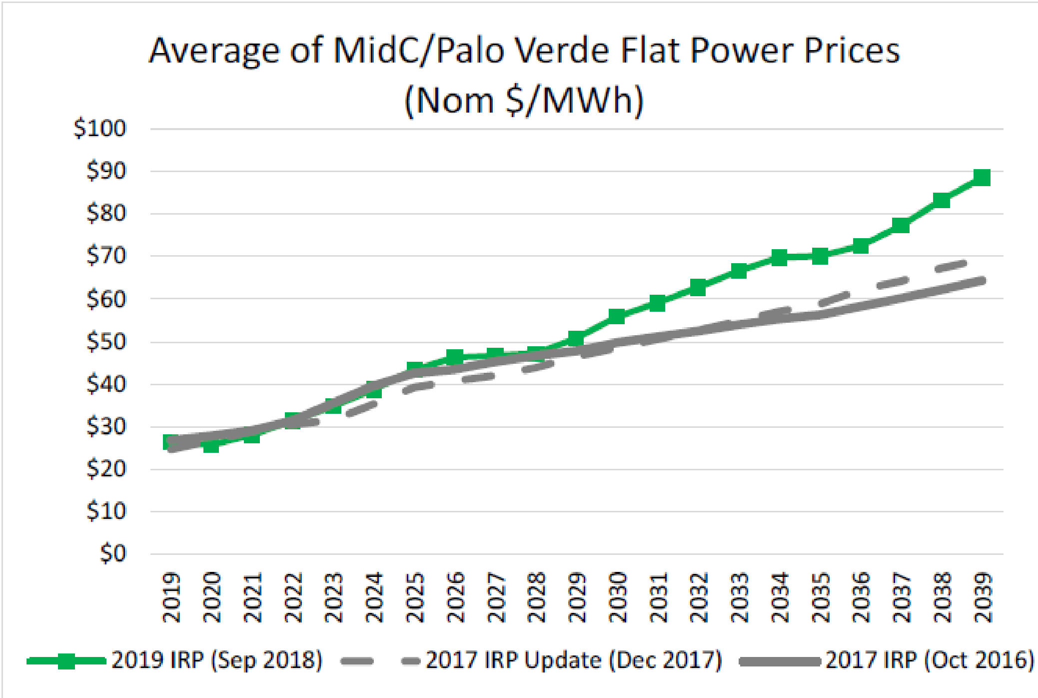
Recommendations:

- **Staff requests that PAC re-run its preferred portfolio to reflect the PTC extension.**
- **Staff requests that PacifiCorp respond to Staff's comments on the PTC expiration by providing additional discussion of how PTC and ITC eligible resources are modeled in the 2019 IRP.**

4.2 MARKET ELECTRICITY PRICE FORECAST

PacifiCorp's market price forecast is a blend of three years of forward market prices followed by a market price forecast in Aurora for the later years of the planning horizon.[41] The market price forecast is an important factor in IRP modeling because market prices affect the economics of new resources. If market prices are high, new resources look more affordable in comparison. The following Figure 8.37 from PacifiCorp's IRP compares the average market price in the 2019 IRP with that from the 2017 IRP.

[38] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 258.
[39] Staff notes that the preferred portfolio adds 10 MW of Yakima Wind + Storage in 2027.
[40] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 132 – 144.
[41] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 180.



[42]

PacifiCorp explains that the increase in prices from the 2017 to the 2019 IRP is "primarily driven by the assumption of a carbon price that is higher and starts earlier (2025) than what was assumed in the 2017 IRP Update (2030). Moreover, the 2019 IRP assumed higher natural gas prices than either the 2017 IRP or 2017 IRP Update as Henry Hub, in particular, is boosted by increasing LNG exports."[43]

Staff is looking into whether the expected carbon prices and gas prices have been included in the market price forecast appropriately.

5. SUPPLY SIDE RESOURCE MODELING AND PLANNING

5.1 TECHNOLOGY IMPROVEMENT TRENDS AND COST UNCERTAINTIES

PAC's 2019 IRP provides helpful discussion of cost uncertainty for supply side resource options, including uncertainty about future wind, solar, storage, and natural gas costs driven by a range of technological,

[42] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 250.
[43] *Id.*

policy, and market factors.[44] For example, PAC provides the following discussion related to the long-term cost trajectory of wind facilities:

> Burns & McDonnell estimates the cost of wind projects will remain mostly flat with cost decreases of less than five percent over the next ten years, while other estimates indicate the LCOE for wind production could decline as much as 20 percent over the next ten years. While the wind industry has faced PTC cliffs in the past, it is difficult to predict how the scheduled phase out of PTC benefits will impact the cost of future wind projects in the market over the next five to ten years.

Staff considers this aspect of the planning environment particularly important due to the timing of the RFP action item. While PAC does not specify a size for the RFP, the preferred portfolio adds approximately 4.3 GW of wind and solar plus storage before the end of 2023, providing approximately 941 MW of capacity contribution in summer and 900 MW of capacity contribution in winter.[45] This occurs years before the load resource balance identifies a deficit (839 MW summer net resource deficit in 2027 and a 399 MW winter net resource deficit in 2028.)

Staff agrees that the RFP action item is likely to capture valuable wind and solar incentives, but notes that this approach carries a risk that future resources could provide an even better economic opportunity.[46] The extension of the PTC is one example of this risk being realized; however, a range of other uncertainties exist.

Despite the helpful discussion, PacifiCorp's treatment of cost uncertainty lacks robustness. PacifiCorp appears to address this cost uncertainty by noting that, "the cost profile between the 2017 IRP and the 2019 IRP has not changed significantly."[47] Staff finds that developing base, high, and low resource cost assumptions would allow more robust consideration of uncertainty. Similar to the approach taken in the Company's Private Generation Assessment, using a range of cost futures can capture technology "learning curves" along with continuation or addition of various policy and market drivers.

Recommendation:

- **Staff recommends that the Company model multiple supply side resource cost scenarios to better reflect technology, policy, and market uncertainty in future IRPs.**

5.2 DAVE JOHNSTON WIND IN 2028

PacifiCorp's preferred portfolio, P-45CNW, is a variation of Portfolio P-45CP with only one difference. PacifiCorp chose to remove a 620 MW wind resource from the Dave Johnston brownfield site in 2028. This decision was based on PacifiCorp's observation that the forecast curtailment at that site decreased the capacity factor from 43.6 percent to 32 percent.[48]

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[44] PacifiCorp 2019 Integrated Resource Plan. Volume I. Pages 127 – 131.
[45] PacifiCorp 2019 Integrated Resource Plan. Volume I. Pages 259 - 262.
[46] PacifiCorp 2019 Integrated Resource Plan. Volume I. Pages 115-118.
[47] PacifiCorp 2019 Integrated Resource Plan. Volume I. Pages 127.
[48] PacifiCorp 2019 Integrated Resource Plan. Volume II. Volume O. Page 236.

Staff does not agree with the reasoning behind PacifiCorp's decision to remove a wind resource from the lowest cost portfolio, especially because the decision results in a preferred portfolio with lower performance to portfolio P-45CP in terms of cost and variability:[49]

Table L.66 – 10-year Average Incremental Customer Rate Impact*

	10-year Average Incremental Customer Rate Impact (2019 - 2028)									
	Low Gas, No CO_2		Medium Gas, Medium CO_2		High Gas, High CO_2		Social Cost of Carbon		Average	
$ Millions	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank	Difference from Preferred Portfolio	Rank
P45CNW	0	4	0	5	0	5	0	6	0	5
P36CP	114	8	102	8	81	8	9	8	77	8
P45CP	(1)	3	(1)	3	(1)	3	0	7	(0)	4
P46CP	4	5	(0)	4	(1)	4	(30)	1	(7)	1
P46J23CP	50	7	34	7	19	7	(28)	2	19	7
P47CP	(7)	1	(5)	1	(2)	2	(1)	5	(3)	2
P48CP	(5)	2	(4)	2	(2)	1	(2)	4	(3)	3
P53CP	18	6	15	6	16	6	(7)	3	11	6

Staff does not find a high level of wind curtailment to be a sufficient reason to remove a resource. Recent studies have indicated that curtailing renewables can be a cost-effective way to serve load, and PacifiCorp's IRP analysis appears to replicate this finding.[50] While the savings are not large on a system basis, they indicate that building a wind resource at the Dave Johnston site after its retirement is cost-effective in the long run, even with high levels of curtailment. Additionally, there may be options to store or convert excess wind energy by 2028.

Staff is also concerned that PacifiCorp's Supply Side Resource table appears to show that Wind + Storage was not considered as an option at the Dave Johnston brownfield site, although it was considered for the Jim Bridger site:

[49] PacifiCorp 2019 Integrated Resource Plan. Volume II. Appendix L. Page 269.
[50] Clean Power Research. Solar Potential Analysis Report. November 15, 2018. Page 3.

Mid-Calendar Year 2018 Dollars ($) Resource Description	Elevation (AFSL)	Capacity Factor 3/	Total Fixed ($/MWh)	Storage Efficiency	Levelized Fuel ¢/mmBtu	 $/MWh
Brownfield Site						
Dave Johnston						
SCCT Frame "F" x1	5050	33%	27.81	na	327	32.11
3.6 MW Wind turbine 43,6% CF WY, 2023 (40% PTC)	6400	44%	31.05	na	0	-
CCCT Dry "J/HA.02", 1x1	5050	78%	19.34	na	320	20.66
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	47.20	na	320	20.66
Hunter						
SCCT Frame "F" x1	5050	33%	27.81	na	327	32.11
PV, 200 MW, 2026, 32.5% CF (10% ITC)	5000	33%	42.31	na	0	-
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	5000	33%	52.29	88%	0	-
CCCT Dry "J/HA.02", 1x1	5050	78%	17.89	na	327	21.17
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	37.77	na	327	21.17
Huntington						
SCCT Frame "F" x1	5050	33%	27.81	na	327	32.11
PV, 200 MW, 2026, 32.5% CF (10% ITC)	5000	33%	42.31	na	0	-
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	5000	33%	52.29	88%	0	-
CCCT Dry "J/HA.02", 1x1	5050	78%	17.89	na	327	21.17
CCCT Dry "J/HA.02", DF, 1x1	5050	12%	37.77	na	327	21.17
Jim Bridger						
3.6 MW Wind turbine 43,6% CF WY, 2023 (40% PTC)	6400	44%	31.05	na	0	-
Wind + Stor, 200 MW+ 50 MW | 400 MWh	6500	44%	47.19	88%	0	-
SCCT Frame "F" x1	6500	33%	27.17	na	321	31.43
PV, 200 MW, 2026, 32.5% CF (10% ITC)	6400	30%	45.15	na	0	-
PV + Stor, 200 MW + 50 MW X 200 MWh (10% ITC)	6400	30%	56.38	88%	0	-
CCCT Dry "J/HA.02", 1x1	6500	78%	18.14	na	321	21.45
CCCT Dry "J/HA.02", DF, 1x1	6500	12%	34.70	na	321	21.45[51]

Staff is continuing to consider whether the removal of the wind project at Dave Johnston was an optimal planning decision, and whether different modeling decisions such as the addition of wind + storage at the Dave Johnston brownfield site could have improved the economics of this resource.

Additionally, Staff is considering PacifiCorp's transmission modeling in the IRP, and whether a buildout of different sections of PacifiCorp's Energy Gateway transmission plan, for example one that included transmission connecting PacifiCorp's Eastern Balancing Authority Area (BAA) to the Western BAA, would have resulted in less curtailment at the Dave Johnston wind project.[52]

Recommendation:

- **PacifiCorp should update the preferred portfolio by allowing wind plus storage at the Dave Johnston site.**

5.3 DISTRIBUTED STANDBY GENERATION

Another program that may help PacifiCorp meet peak load cost-effectively is a distributed standby generation program in collaboration with large customers. A Distributed Standby Generation program has proven to be cost-effective in PGE's service territory, at an estimated cost of $41/kW-yr.[53] This program offers a fleet of customer-located diesel generators that provide non-spinning contingency reserves to meet PGE's North American Electric Reliability Corporation (NERC) requirements.

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[51] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 143.
[52] See Section 7 of these comments for further analysis of transmission in the 2019 PacifiCorp IRP.
[53] LC 73, PGE 2019 IRP. Volume II. Appendix E. Page 282.

Similar to PGE's DSG program,[54] Staff notes there may be opportunity to engage customers in PacifiCorp's service territory to discuss the possibility of an agreement that provides maintenance of standby generation for large customers, and gaining the ability to use the standby generation to meet PacifiCorp's peak load when necessary.

Recommendations:

- **PacifiCorp should report back to the Commission on the feasibility of contacting customers to gauge interest in a distributed standby generation agreement.**
- **Should customer interest exist, PacifiCorp should report back to the Commission on the viability of implementing a Distributed Standby Generation program.**

5.4 ENERGY IMBALANCE MARKET

Staff notes that while the benefits of the Energy Imbalance Market (EIM) regarding regulation reserves have been included in PacifiCorp's 2019 IRP modeling, and commends the Company for considering this aspect of the EIM, there may be other impacts of EIM participation on PacifiCorp's system that have not been fully considered in the IRP. Staff is concerned that this IRP may not consider the effects of EIM commitment and dispatch on PacifiCorp's existing and new generating resources. Staff is continuing to investigate the effects of the EIM on PacifiCorp generator dispatch and how further consideration of EIM participation might change the resources selected in IRP portfolios.

5.5 ENERGY STORAGE POTENTIAL EVALUATION

Staff appreciates PacifiCorp's in-depth analysis of energy storage value and potential in Appendix Q. However, Staff notes that there has not been substantial discussion in the 2019 IRP about battery site remediation and disposal of batteries after their useful life. While Power Purchase Agreement (PPA) contracts for battery resources may include expected costs of site remediation and battery disposal, any PacifiCorp-owned battery resources would need to be disposed of properly by the Company at the end of their useful life. This type of analysis should be included in an IRP if PacifiCorp is considering the possibility of owning its own battery storage resources.

In Docket No. UM 1857, PacifiCorp submitted its Storage Project Proposal for evaluation by the Commission, and in Order No. 18-327 a stipulation was adopted outlining an agreed approach to developing two energy storage projects by PacifiCorp. Staff encourages the Company to use the learnings of this pilot program to improve its understanding of how to optimally utilize storage resources and model them in future IRPs.

[54] Portland General Electric. 2016 Integrated Resource Plan. Page 194

Recommendation:

- **Staff requests that, if batteries are still a prominent resource considered in the next IRP, PacifiCorp should include in its next IRP a study of potential battery storage remediation, recycling, and disposal methods and costs.**

6. DEMAND SIDE MANAGEMENT (DSM) RESOURCE MODELING AND PLANNING

In the 2019 IRP PacifiCorp separates DSM resources into four classifications:

- Class 1 – demand response
- Class 2 – energy efficiency
- Class 3 – time-of-use/critical pricing rates
- Class 4 – customer practice adaptation

Staff comments will focus on Classes 1-3 while noting Class 4 (e.g., a behavioral-based resource such as education and information) does have long-term, though difficult to quantify, benefits.

6.1 CLASS 1 DSM – DEMAND RESPONSE

In the 2017 IRP, Pacific Power proposed 0 MW of incremental demand response for the State of Oregon, and 0 MW for the total system, within the IRP action window per the Preferred Portfolio. It proposed 365 MW of incremental demand response over the 20-year planning horizon, beginning in 2028.[55] There were no demand response Action Items.

The Oregon Irrigation Load Control Pilot launched and achieved stable, limited capacity savings of approximately 550 kW from 2016-2018.[56] In late 2019 Pacific Power filed to extend this pilot to 2023 and expand the capacity savings to approximately 5,000 kW.[57]

In the 2019 IRP action plan window Pacific Power proposes to acquire 0 MW of incremental demand response for the State of Oregon[58] and 29.2 MW for the total system, per the 2019 IRP Preferred Portfolio:[59]

		2019	2020	2021	2022	2023
Oregon		0	0	0	0	0
Total System		4.1	0	7.0	0	18.1

[55] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 244.
[56] Advice 16-04. 2018 Report on Pacific Power's Irrigation Load Control Pilot Program. Page 8. https://edocs.puc.state.or.us/efdocs/HAD/adv242had153034.pdf
[57] Advice 19-008. Supplemental Filing and Replacement Tariff Sheets with Change in Effective Date. https://edocs.puc.state.or.us/efdocs/UAB/adv989uab16620.pdf
[58] PacifiCorp intentionally excludes the Oregon Irrigation Load Control Pilot from this calculus.
[59] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 258

Action Item 4a notes this system wide addition: PacifiCorp will acquire cost-effective Class 1 DSM in Utah targeting approximately 29 MW of incremental capacity from 2020 through 2023. 444 MW of incremental demand response are proposed over the 20-year planning horizon.

Cost-effectiveness of Demand Response in IRP Modeling

While Staff does not oppose the 2019 IRP requirement that the System Optimizer pair solar with storage because it represents an improvement in terms of NPVRR, Staff is considering the extent to which requiring solar to be chosen paired with storage may be reducing the cost-effectiveness of demand response in the 2019 IRP.

PacifiCorp's 2019 IRP preferred portfolio includes nearly 600 MW of battery storage by the end of 2023 (these storage resources are paired with new solar generation). The plan also adds nearly 1,400 MW of stand-alone storage resources starting in 2028. Yet Staff notes Tables 6.6 and 6.7 (Demand Response Program Attributes West Control Area, and the East Control Area, respectively) which forecast winter levelized demand response costs ranging as low as $7/kW-yr in the West, and summer levelized demand response costs ranging as low as ($4)/kW-yr in the East. These costs appear to be less expensive than battery storage.

In Table 5.11 PacifiCorp notes 177 MW of interruptible contracts as an Existing DSM Resource, and in response to Staff data request No. 59 stated these participants are located in Utah and Idaho, in the East Control Area. Staff again notes Tables 6.6 and 6.7 which show that Third Party Contracts are forecast cheaper-to-comparable in the West in the summer, and cheaper in the West in the winter. Staff notes the Energy Partner Pilot in PGE's service territory is an evolved, non-residential, direct load control offering which recently achieved nearly 12 MW of demand reduction per event.[60] Given PacifiCorp's base of large customers in Oregon (approximately 900 customers with service between 201-999 kW, and approximately 200 customers with service greater than 1 MW),[61] Staff wonders how many additional opportunities for Third Party Contracts in the West are being missed.

To underscore the apparent cost differences, Staff reviewed demand response products from Table 6.6 (focusing more closely on just the West Control Area) and supply-side resources from Table 6.2 in the 2019 IRP. A selection of the products and resources are arranged below, ordered with the least-cost option first, increasing approximately (as costs are often a range).

[60] UM 1514. Energy Partner Demand Response Performance Report. https://edocs.puc.state.or.us/efdocs/HAH/um1514hah17641.pdf

[61] UE 356/Advice No. 19-007. Transition Adjustment Mechanism. Exhibit PAC/304, Ridenour/1. https://edocs.puc.state.or.us/efdocs/HAA/ue356haa152413.pdf

Table 4 – Demand Response Product Levelized Cost

Demand Response Products – Summer (unless otherwise labeled winter) **& Supply-Side Resources (highlighted grey)**	Levelized Cost ($/kW-yr)
DLC Space Heating Res & C&I - **WINTER**	$7 - $27
Ancillary Services	$14 - $20
DLC Irrigation	$37 - $40
DLC Cooling & WH - Res and C&I	$44 - $48
DLC Smart Thermostat - Res	$31 - $54
DLC Smart Thermostat - Res - **WINTER**	$30 - $91
Third Party Contracts	$55 - $56
Third Party Contracts - **WINTER**	$94 - $100
Ice Energy Storage	$134
DLC Cooling & WH - Res and C&I - **WINTER**	$136 - $157
PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh (30% ITC)	$155.58 Total Fixed ($/kW-Yr)
PV + Stor, Lakeview, OR, 200 MW + 50 MW X 200 MWh (10% ITC)	$155.58 Total Fixed ($/kW-Yr)
Wind + Stor, Arlington, OR, 200 MW+ 50 MW | 200 MWh	$163.00 Total Fixed ($/kW-Yr)
Oregon PS, 400 MW X 3,800 MWh	$206.85 Total Fixed ($/kW-Yr)
Li-Ion 15 MW X 60 MWh	$207.93 Total Fixed ($/kW-Yr)
DLC Smart Appliance - Res	$210
DLC Room AC - Res	$352
DLC Elec Vehicle Charging - Res	$763

Staff looks forward to further discussion, and better understanding, about the cost-effectiveness of demand response in IRP modeling such that it is clear that the resources in question are being evaluated on a consistent and comparable basis.

Demand response in the 2015 IRP

In Order 16-071 the Commission ordered the following regarding 2015 IRP Action Item 3 – Demand Side Management Actions:

> We acknowledge Action Item 3a. However, in addition to the Action Item 3a irrigation pilot program, we direct PacifiCorp to design and present additional pilots. We remain concerned PacifiCorp has not placed enough attention on developing demand response as a viable and significant resource on the western portion of its system. The company needs practical experience designing and running demand response programs - experience in other states is of limited use given the climatic, population, and other distinctive characteristics of Oregon. In addition, robust demand response programs could serve as a source of flexibility reserves as we add more wind and solar generation. We adopt the following recommendation:
>
> > Present at a public meeting within six months of this order, potential demand response pilot programs including: a time-varying rate pilot, peak-time rebate, and direct load

control program for other sectors. The company may also consider demand bidding programs.[62]

Before the next round of Staff comments, staff would like to meet with PacifiCorp to reinvigorate the discussion about demand response pilots as was initiated in Order 16-071.

Additional Opportunity for Demand Response in Oregon

Staff notes there are a number of recent studies identifying resource adequacy concerns in the coming years for the Pacific Northwest, some with greater levels of urgency.[63] To that end, the Northwest Power and Conservation Council's Seventh Power Plan found demand response to be the least-cost solution for providing new peaking capacity, and that at least 600 megawatts should be developed to meet peaking needs and satisfy regional resource adequacy standards.[64]

Putting that regional need in the context of PacifiCorp's own efforts, Staff calls out the achievements of Rocky Mountain Power programs during recent years:

- Rocky Mountain Power's Idaho Irrigation Load Control program was cost effective in 2015, 2016, 2017, and 2018. During these years, the program worked with approximately 200 customers at over 1,000 sites and achieved maximum realized load reductions of between 163-169 MW.[65]

[62] Docket No. LC 62. Order 16-071, page 6, https://apps.puc.state.or.us/orders/2016ords/16-071.pdf

[63] See Resource Adequacy in the Pacific Northwest, March 2019, Energy and Environmental Economics, page iii (https://www.ethree.com/wp-content/uploads/2019/03/E3_Resource_Adequacy_in_the_Pacific-Northwest_March_2019.pdf) or Pacific Northwest Power Supply Adequacy Assessment for 2024, October 31, 2019, Northwest Power and Conservation Council, page 5. (https://www.nwcouncil.org/sites/default/files/2024%20RA%20Assessment%20Final-2019-10-31.pdf) for one perspective. See 2018 Long-Term Reliability Assessment, December 2018, North American Electric Reliability Corporation, page 127. (https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf) for a different perspective.

[64] Northwest Power and Conservation Council, Seventh Northwest Conservation and Electric Power Plan, Chapter 1, page 1-6 (https://www.nwcouncil.org/sites/default/files/7thplanfinal_chap01_execsummary_6.pdf)

[65] Idaho Energy Efficiency and Peak Reduction Annual Report, April 29, 2016, Rocky Mountain Power, page 34 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/idaho/2015_ID_Annual_Report_Final.pdf).
Idaho Energy Efficiency and Peak Reduction Annual Report, May 1, 2017, Rocky Mountain Power, page 33 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/idaho/2016_Idaho_DSM_Annual_Report+Appendix.pdf).
Idaho Energy Efficiency and Peak Reduction Annual Report, April 24, 2018, Rocky Mountain Power, page 34 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/idaho/ID_PAC-E-05-10-2017-DSM-Report4-24-18.pdf).
Idaho Energy Efficiency and Peak Reduction Annual Report, April 30, 2019, Rocky Mountain Power, page 34 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/idaho/2018_ID_DSM_Annual_Report_Appendices.pdf).

- Rocky Mountain Power's Utah Irrigation Load Control program was cost effective in 2015, 2016, 2017, and 2018. During these years, the program worked with approximately 50 customers at over 200 sites and achieved maximum realized load reductions of between 11-13MW.[66]

- Rocky Mountain Power's Utah Cool Keeper program was cost effective in 2015, 2016, 2017, and 2018. During these years, the program worked with approximately 105,000 customers and achieved maximum realized load reductions of between 89-201 MW.[67]

Staff also notes Section 19(3) of Oregon Senate Bill 1547 passed in 2016, codified at ORS 757.054:[68]

> *(3) For the purpose of ensuring prudent investments by an electric company in energy efficiency and demand response before the electric company acquires new generating resources, and in order to produce cost-effective energy savings, reduce customer demand for energy, reduce overall electrical system costs, increase the public health and safety and improve environmental benefits, each electric company serving customers in this state shall:*
> *(a) Plan for and pursue all available energy efficiency resources that are cost effective, reliable and feasible; and*
> *(b) As directed by the Public Utility Commission by rule or order, plan for and pursue the acquisition of cost-effective demand response resources.*

Given 1) concerns about resource adequacy in the region, 2) the identification of demand response as a least-cost resource for peaking capacity, 3) PacifiCorp's success in achieving substantive, cost-effective demand reduction in other states, and 4) Oregon's statutory requirement for demand response, Staff

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[66] Utah Energy Efficiency and Peak Reduction Annual Report, May 23, 2016, Rocky Mountain Power, page 18 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/utah/UT_Energy_Efficiency_and_Peak_Reduction_Report.pdf).
Utah Energy Efficiency and Peak Reduction Annual Report, June 15, 2017, Rocky Mountain Power, page 17 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/utah/Energy_Efficiency_and_Peak_Reduction_Report_2016(6-30-17).pdf).
Utah Energy Efficiency and Peak Reduction Annual Report, May 18, 2018, Rocky Mountain Power, page 18 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/utah/Energy_Efficiency_and_Peak_Reduction_Report_2017.pdf).
Utah Energy Efficiency and Peak Reduction Annual Report, June 18, 2019, Rocky Mountain Power, page 17 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/utah/Energy%20Efficiency%20and%20Peak%20Reduction%20Report%202018%20(Utah).pdf).
[67] Utah Energy Efficiency and Peak Reduction Annual Report, May 23, 2016, Rocky Mountain Power, page 20 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/utah/UT_Energy_Efficiency_and_Peak_Reduction_Report.pdf).
Utah Energy Efficiency and Peak Reduction Annual Report, June 15, 2017, Rocky Mountain Power, page 19 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/utah/Energy_Efficiency_and_Peak_Reduction_Report_2016(6-30-17).pdf)
Utah Energy Efficiency and Peak Reduction Annual Report, May 18, 2018, Rocky Mountain Power, page 20 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/utah/Energy_Efficiency_and_Peak_Reduction_Report_2017.pdf).
Utah Energy Efficiency and Peak Reduction Annual Report, June 18, 2019, Rocky Mountain Power, page 19 (https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/utah/Energy%20Efficiency%20and%20Peak%20Reduction%20Report%202018%20(Utah).pdf).
[68] ORS 757.054(3).

has serious concerns whether PacifiCorp is making a good faith effort to plan for and pursue cost-effective demand response program offerings, and their associated demand reductions, in Oregon.

Couple these concerns with the apparent cost differences of demand response and the proposed battery storage, and Staff cannot 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.

Recommendations:

- **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.**
- **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.**
- **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.**

6.2 CLASS 2 DSM – ENERGY EFFICIENCY

In the action plan window, PacifiCorp proposes to acquire the following amounts – in MWh – of incremental energy efficiency by state and for the total system, per the 2019 IRP Preferred Portfolio:[69]

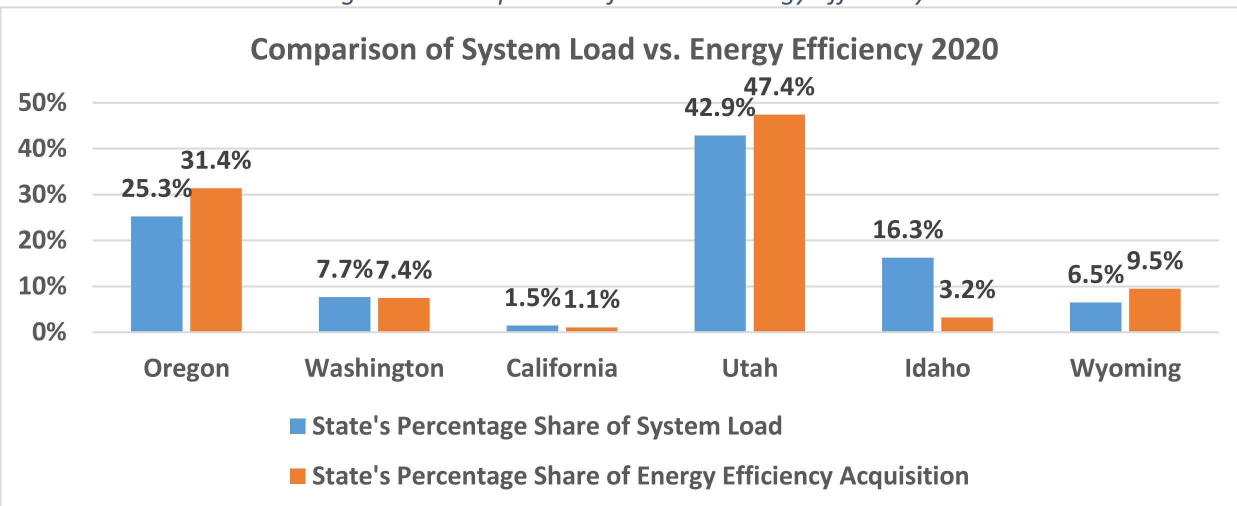
	2019	2020	2021	2022
Oregon	182,370	168,410	165,580	177,040
California	5,130	5,710	5,270	5,540
Washington	42,090	39,900	40,550	44,450
Utah	255,470	254,270	254,120	254,590
Idaho	18,100	17,190	17,590	18,410
Wyoming	59,320	50,960	54,960	71,250
Total System	562,480	536,440	538,070	571,280

Staff references the requirement of ORS 757.054(3)(a) to "Plan for and pursue all available energy efficiency resources that are cost effective, reliable and feasible."[70]

[69] PacifiCorp 2019 Integrated Resource Plan. Volume II. Appendix D. Page 72
[70] ORS 757.054(3).

Staff compared data from this table with the Company's load forecast, also in annual MWh.[71] The following chart compares the percentage of system load attributed to a state as forecasted for 2020, with the proposed incremental addition of energy efficiency in 2020 from the 2019 Preferred Portfolio.

Figure 9 – Comparison of Load vs. Energy Efficiency

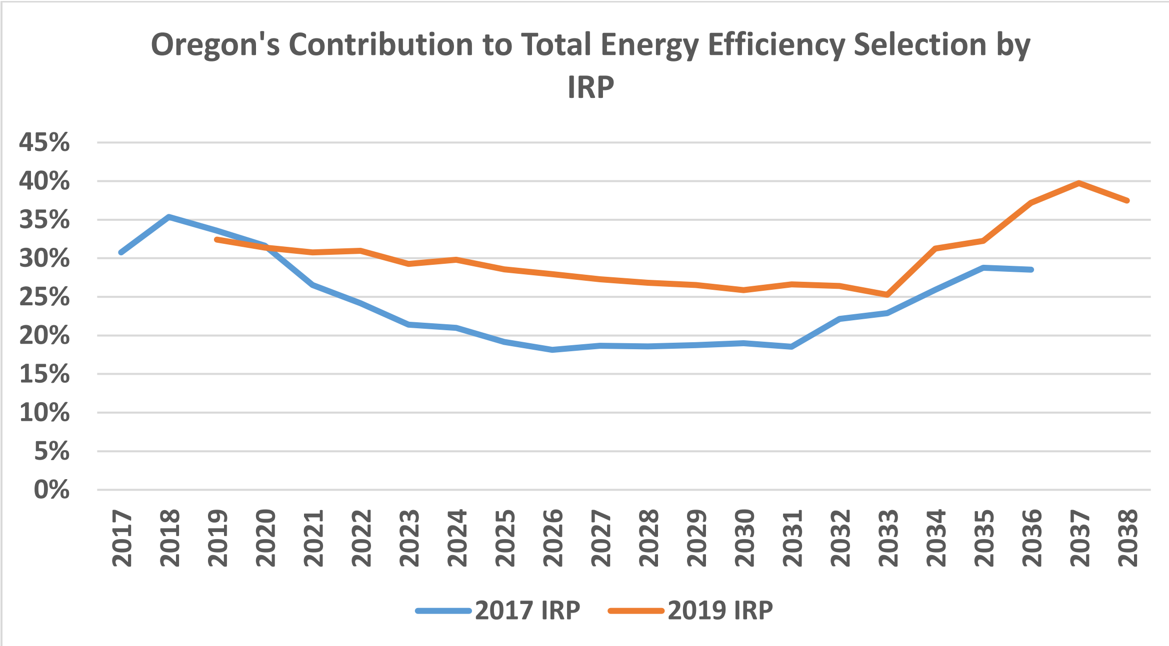


These numbers indicate that energy efficiency selections are disproportionately higher in Oregon compared to its overall share of system load. The discrepancy between energy efficiency selections and system load was noted in Staff's comments in the 2017 IRP.[72] Staff is concerned that not only are energy efficiency activities subsidizing system benefits to other states, but that Oregon ratepayers are also not seeing the system benefits from cost-effective energy acquisitions that are not being pursued in other states. The following graph illustrates the disproportionate share of Oregon energy efficiency over the study period and how the disparity has increased since the previous IRP, indicating that a concern identified by Staff in the previous IRP has only grown in severity.

[71] PacifiCorp 2019 Integrated Resource Plan. Volume II. Appendix A. Page 2

[72] LC 67. PacifiCorp 2016 Integrated Resource Plan. Staff Final Comments. Page 35.

Figure 10 – Oregon's Contribution to Total Efficiency Selection



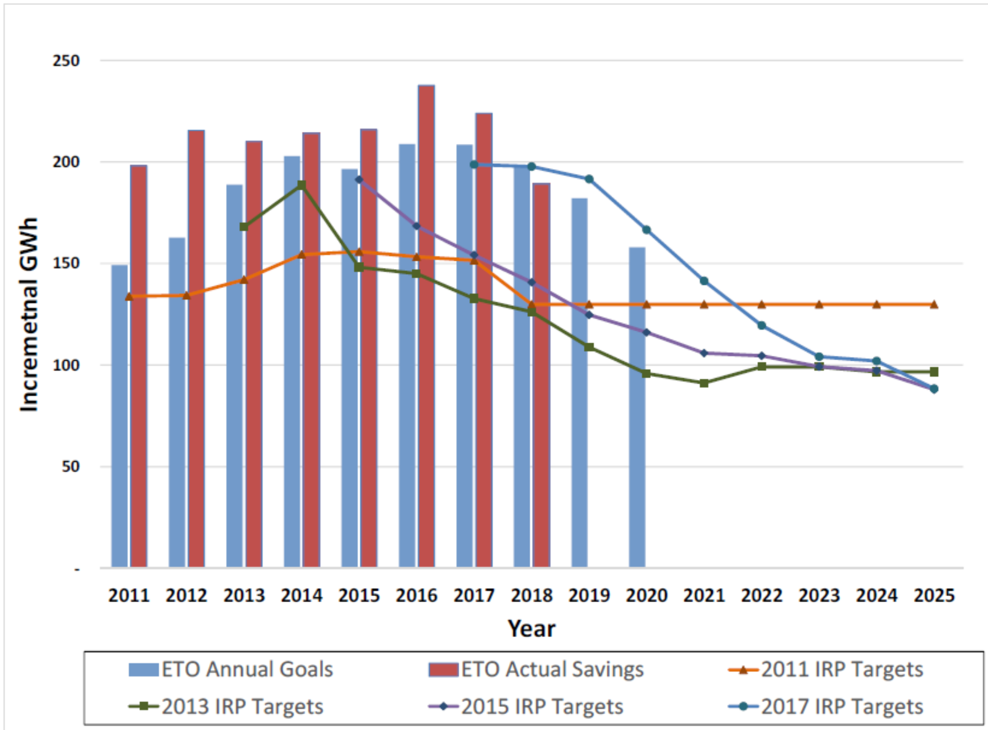
Additionally, Staff has questions about how the capacity contributions of energy efficiency are calculated, particularly contributions to peak. Staff intends to review these assumptions along with other demand side resources for consistency and appropriateness.
In the 2017 IRP, modified Action Item 4a established that the company shall: pursue all cost-effective energy efficiency, hold a DSM stakeholder workshop, and create a report on differences in the IRP forecast vs. Energy Trust's. This last action item, as modified through Order No. 18-420, reads:

> PacifiCorp, in coordination with Staff and the Energy Trust of Oregon, will conduct an analysis by the next IRP that identifies and compares the ongoing differences between ETO's and PacifiCorp's near to long term energy efficiency forecast with ETO's actual achieved savings. PacifiCorp will report on the outcomes of this analysis, including any recommendations to both organizations regarding forecasting improvements, in the 2019 IRP.

In response to this order, the company and Energy Trust worked together to compare their processes, identify potential sources of discrepancy, and discuss their findings with stakeholders. The following chart from the report filed in this docket illustrates the discrepancies between forecasts.[73]

[73] Oregon Energy Efficiency Forecasting Analysis Report, April 5, 2019 located at: https://edocs.puc.state.or.us/efdocs/HAD/lc70had135438.pdf.

Figure 11 - Comparison of Historical and Forecasted ETO Savings to PacifiCorp's IRP Targets [74]



The parties identified a number of potential sources of discrepancy in forecasts, while also ruling out a number of possibilities. Opinions differed on the contribution of a couple potential sources. However, there are two sources that the parties agree on as significant drivers of difference: Energy Trust's historic overachievement vs. goals, and the uncertainty of large energy-saving opportunities. Another factor is the timing of when Energy Trust establishes annual goals and the IRP schedule. This is of particular note as Energy Trust's forecast for future savings has declined since the publication of this IRP. In this forecasting analysis report, Energy Trust notes that the following changes were made after the 2017 IRP and are reflected in the 2019 IRP: applying "calibration" from program staff feedback to five years of energy efficiency acquisition instead of two, enhanced emerging technology modeling, applying a large project adder, updates to measure savings assumptions, and incorporating additional measures from other states, including air conditioning measures.

After conducting this joint research, the parties came up with the following recommendations: 1) PacifiCorp and ETO coordinate with stakeholders through UM 1893 and other engagements to discuss energy efficiency forecasting, 2) PacifiCorp continue to study different bundling approaches as had been proposed in the last IRP, and 3) Energy Trust consider applying an adder to account for historic overachievement against goals.

As a follow-up to the second recommendation, the Company presented its analysis of an alternative bundling strategy in a public stakeholder presentation. The analysis was somewhat limited, and the

[74] Oregon Energy Efficiency Forecasting Analysis Report, April 5, 2019, page 8 located at: https://edocs.puc.state.or.us/efdocs/HAD/lc70had135438.pdf.

Company determined that the proposed method did not produce the desired results of improving selections for capacity at least cost. Staff felt that the approach could be simplified and that there are opportunities to identify benefits through more incremental improvements to bundling strategies. The Company intends to continue to study new bundling approaches for the next IRP. Staff feels that this research is important and needs to continue. Staff will continue to engage in the discussion of alternative methods.[75]

Since this report was Oregon-specific, Staff did not explore comparisons to methodologies used in other states. Given the discrepancy noted above between Oregon's load forecast and energy efficiency acquisition selections, Staff finds it important to determine what learnings from this analysis could potentially be applied to other states to improve energy efficiency selection across the system. Staff will follow up with the Company on the status of these improvements.

Recommendations:

- **Explain why other states are not experiencing similar levels of Class 2 DSM growth as Oregon is in LC 70.**
- **Provide state-by-state data of the state winter and summer peak (MW) relative to Class 2 DSM MW contribution for 2020 through 2030, so as to understand how Oregon is contributing to local and system peaks.**
- **PacifiCorp should continue to study alternative bundling approaches for application in future IRPs.**
- **PacifiCorp should report back to the Commission on what learnings from its ongoing work to improve energy efficiency selection with Energy Trust and from the Oregon Energy Efficiency Forecasting Analysis Report should be applied to forecasting in other states to ensure the appropriate level of energy efficiency is properly selected.**

6.3 CLASS 3 DSM – TIME-OF-USE / CRITICAL PRICING RATES

For the purposes of the 2019 IRP, PacifiCorp defines Class 3 DSM as "price response and load shifting programs" that "seek to achieve short duration (hour by hour) energy and capacity savings from actions taken by customers voluntarily, based on a financial incentive or signal."[76]. Program examples include time of use (TOU) pricing plans, critical peak pricing (CPP) plans, and inverted block rate (IBR) tariff designs. For the remainder of this section Staff adopts the same PacifiCorp reference for all these programs: *Class* 3 DSM.

The Class 3 DSM offerings currently available to PacifiCorp customers include metered time of day and TOU pricing plans (in all states), residential seasonal inverted block rates (in ID and UT) and residential year-round inverted block rates (CA, OR, WA, WY). In its IRP, PacifiCorp noted that as of December 31,

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[75] 2019 Integrated Resource Plan (IRP) Public Input Meeting. October 3-4 2019. Pages 77-80. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019-irp/2019-irp-presentations-and-schedule/2019-10-3-4-General_Public_Meeting.pdf.

[76] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 105.

2017, approximately 17,500 customers were participating in metered time of day and TOU programs system wide.[77]

Though current Class 3 DSM offerings do provide capacity and energy savings, these savings are not accounted for directly in the resource planning process.

PacifiCorp states Class DSM 3 is less suited to resource planning “at least until their size and customer behavior profile provide sufficient information needed to model and plan for a reliable and predictable impact,” and notes that Class 3 DSM “[s]avings are typically only sustained for the duration of the incentive offering and, in many cases, loads tend to be shifted rather than be avoided.”[78] This calls for PAC to develop and implement pilots to test TOU strategies that can be counted upon for resource purposes.

PacifiCorp further asserts that Class 3 DSM is captured naturally in historical loads that form the basis for the long-term load growth patterns and forecasts used in development of the IRP. In Table 5.11, PacifiCorp estimates 98 MW of summer peak energy savings due to existing time based pricing, and 55-149 GWh of energy savings due to existing inverted rate pricing.

Staff believes this is far too passive of an approach to what could be a very cost-effective and reliable peak-load reduction tool, if properly implemented and managed. Staff does not disagree that the effect of current Class 3 DSM offerings can be captured through historical usage, given the Company’s passive approach to this resource. However, as the Company and Commission begin to engage in efforts to pilot improved Class 3 DSM offerings, and programs that modify, or expand its Class 3 DSM offerings, the incremental energy and capacity savings resulting from such changes will not be captured through historic loads. Staff is therefore concerned that when PacifiCorp adopts a more dynamic approach to Class 3 DSM offerings, the effect of the corresponding capacity and energy savings will not be captured in the IRP planning process. Staff believes PAC should engage with Staff and stakeholders between now and the next IRP to discuss both improving Class 3 DSM offerings and how to better capture those cost-effective peak demand reductions in the Company’s IRP modeling.

For example, if the Company plans to broadly expand TOU rates, perhaps through the introduction of an Electric Vehicle (EV) TOU rate,[79] or the introduction of a CPP program, it can no longer be said that, for planning purposes, the effect of Class 3 DSM offerings is captured naturally in the load forecast. As these offerings are not currently available, they are by definition not reflected in load growth patterns absent an additional variable or mechanism. If the Company does plan for the expansion of such programs, an adjustment to the load forecast, or an after the fact reduction as is done with Class 2 DSM, may be needed to capture the estimated peak load reduction and its corresponding effects to the IRP at large.

Staff notes that this is particularly relevant as the Company continues the deployment of AMI throughout its service territory. One advantage to AMI is the potential to utilize real time usage data from customers to inform innovative rate design and program offerings. Once AMI has been fully

[77] PacifiCorp 2019 Integrated Resource Plan. Volume II. Appendix D. Page 68.
[78] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 105.
[79] The current Oregon TOU offering is Schedule 210, Portfolio Time-of-Use Supply Service. Applicable to Residential and Small Nonresidential Consumers receiving Delivery Service under Schedules 4, 5, 23 or 41, in conjunction with Supply Service Schedule 201. The current TOU offering is an adjustment schedule, which credits customers for usage during the off-peak period, and adds surcharge for usage during the on-peak period.

deployed in Oregon, Staff would hope to see the Company attempt to utilize this data for such purposes. For example, Staff would be interested in exploring with the Company whether customers may benefit from the refinement and introduction of additional TOU offerings and CPP rates.

The Conservation Potential Assessment for 2019-2038 estimates total DSM potential for the 2019-2038 time period, and the estimates for Class 3 DSM total market potential by option and State in 2038 are displayed below.[80]

Table 2-3 Class 3 DSM Total Market Potential by Option and State in 2038 (MW)

Program	CA	ID	OR	UT	WA	WY	Total
Residential TOU Demand Rate	0.3	0.9	4.8	26.9	1.9	2.4	**37.3**
Residential TOU Demand Rate with EV	0.1	0.2	1.5	5.6	0.3	0.1	**7.9**
Residential TOU	0.9	0.0	16.7	38.4	6.6	3.5	**66.1**
Residential TOU with EV	0.2	0.0	3.0	11.3	0.6	0.2	**15.4**
Residential CPP	1.2	1.8	22.3	51.1	8.8	4.6	**89.8**
Residential Behavioral DR	0.3	0.7	4.8	9.2	1.0	1.1	**17.1**
C&I TOU	0.1	0.3	2.5	5.6	1.1	1.0	**10.5**
C&I CPP	0.6	1.0	17.4	36.1	6.1	15.7	**76.8**
C&I RTP	0.1	0.1	3.0	6.0	0.8	3.6	**13.7**
Irrigation TOU	0.2	2.0	0.6	0.5	0.3	0.1	**3.7**
Irrigation CPP	0.7	7.9	2.2	1.8	1.3	0.3	**14.3**
Total	**4.5**	**15.1**	**78.9**	**192.5**	**28.9**	**32.6**	**352.5**

As seen in the table above, the total Class 3 DSM incremental market potential is 352.5 MW in 2038. For Oregon, the potential estimate is 78.9 MW, with approximately 22 MW coming from residential CPP, and another 16.7 MW from residential TOU. While Staff notes that these potential savings are shown for 2038, Staff believes this highlights the need to understand how Class 3 DSM expansion effects the IRP and why these programs cannot occur much earlier in the planning cycle, if not within the IRP Action Plan window.

Staff agrees with the Company that the incremental effect of Class 3 DSM offerings is difficult to determine. However, Staff believes it is precisely because of this difficulty in teasing out the capacity and energy savings of Class 3 DSM offerings, that parties should work together to determine how best to include future Class 3 DSM offerings in the resource planning process to ensure their potential energy and capacity savings are appropriately accounted for.

[80] PacifiCorp Conservation Potential Assessment for 2019-2038. Volume 1, Page 12. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/environment/dsm/2019-final-study/PacifiCorp_DSM_Potential_Vol_1_Executive_Summary_Final_2019-6-30.pdf ; see also 2019 PacifiCorp Integrated Resource Plan, Appendix D.

Recommendations:

- **PacifiCorp should work with Staff to understand the data collected by AMI in PacifiCorp's Oregon service territory and to determine the appropriateness of utilizing AMI to develop EV TOU rates, CPP, and ways to leverage the deployment of Class 3 DSM to strengthen the effects of demand response offerings.**
- **Before the next IRP, PacifiCorp should hold a workshop with parties to discuss the development of potential Class 3 DSM pilot offerings, especially for electric vehicle owners, and to explore how the resource planning process can be improved to either better reflect Class 3 DSM as a load reduction or select it as a supply resource.**
- **PacifiCorp should introduce a TOU/CPP/DPP rate in Oregon for all rate classes within one year, or in the next general rate case, whichever occurs first. Work with Staff through a workshop and a filing in LC 70 for development of a proposed TOU rate.**

7. TRANSMISSION RESOURCES

7.1 TRANSMISSION SELECTION IN IRP PORTFOLIOS

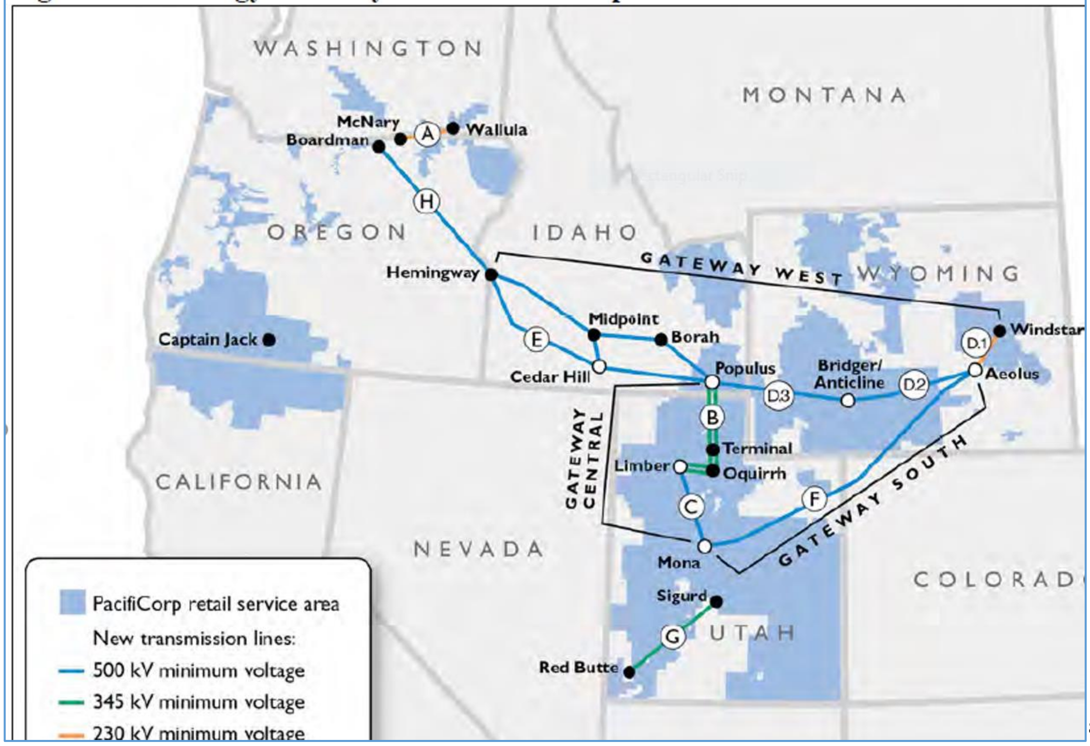
As described in PacifiCorp's Public Input Meeting presentation of November 2019, PacifiCorp has been able to include some transmission investments as resource options available for endogenous selection by the SO capacity expansion model. This update to the IRP modeling capabilities allows some transmission projects to be selected in an optimal year as part of a portfolio of generation resources chosen by the model to minimize system costs over the planning horizon. Although Staff commends PacifiCorp for using SO to help select transmission projects that provide benefits to the system, the following comments will address some concerns with the Company's transmission modeling assumptions.

It is important to note that not every transmission option can be selected endogenously by System Optimizer due to the model's limitations. PacifiCorp reports that some transmission projects, including two substantial Energy Gateway projects in Oregon and Idaho, cannot be selected endogenously by the model. [81,82]

Out of the remaining Energy Gateway (EG) segments that have not yet begun construction (segments D.1, D.3, E, F, and H), only Energy Gateway segments D.1, D.3, and F (located in PacifiCorp's eastern service territories) could be selected endogenously by SO.[83] Segments H and E, (located in Oregon and Idaho) were not available for selection by SO in the 2019 IRP. The segments are shown in the map below:

[81] See PacifiCorp response to Staff Data Request 91, included in Attachment A to these initial comments.
[82] See PacifiCorp response to Staff feedback form of July, 11, 2019, describing why some resources cannot be selected by System Optimizer, included in Attachment A to these comments.
[83] 2019 PacifiCorp Integrated Resource Plan. Table 6.11. Page 169.

Figure 4.3 – Energy Gateway Transmission Expansion Plan



[84]

Energy Gateway Cases

In order to study the Energy Gateway segments that could not be selected endogenously by SO, PacifiCorp considered four additional Energy Gateway cases (portfolios) in the IRP, as reflected in the following chart.

Table 7.14 – Additional Gateway Case Definitions

Case	P-22	P-23	P-25	P-26
Base Case	P-45CNW	P-36CNW	P-45CNW	P-45CNW
Segments*	(D3), (F)	(D3), (E), (F), (H)	(D3), (E), (F), (H)	(F), (H)

[85,86]

PacifiCorp reveals that for P-23 and P-25, the model returns results that are approximately one billion dollars more expensive than the preferred portfolio, P-45CNW. [87] This is wholly unsurprising, as the additional costs are due to incremental Energy Gateway segment buildout. Similarly for P-22, costs

[84] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 84.
[85] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 203.
[86] PacifiCorp reports that in each of the four Energy Gateway Cases, Energy Gateway South was selected endogenously by the model in 2023. [86]
[87] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 242.

increase by about $400 million.[88] In these portfolios, System Optimizer has endogenously selected Gateway South (Segment F) and PacifiCorp has manually "tacked on" additional transmission resources to compare costs.

Staff finds that the Company's approach to transmission modeling may not be sufficient to fully assess the economics of the western transmission segments that could not be selected endogenously in System Optimizer. Only one in-service year is considered for each segment, with Segment H (B2H) in service in 2026, Segment D.3 (Bridger/Anticline to Populus) in service in 2025, and Segment E (Populus to Hemingway) in service in 2025.[89] Staff is not convinced that PacifiCorp's analysis proves the in-service dates considered for Segment E or H are least cost options for customers. For example, IRP analysis has not considered whether an earlier 2024 energization date of B2H could potentially allow interconnection of incremental generation resources, including PTC wind outside of Wyoming, to one of these lines instead of Energy Gateway South (EGS).

7.2 ENERGY GATEWAY SOUTH AND BOARDMAN TO HEMINGWAY

As explained above, the method through which transmission was modeled in this IRP appears to have impacted the order and prioritization of some planned transmission projects, including Energy Gateway South and Boardman to Hemingway.

The transmission analysis in the IRP portfolios does not fully assess whether Energy Gateway and related transmission segments are logically prioritized and well-timed in relation to each other, or are even necessary at all. For example, it is unclear whether benefits now associated with Gateway Central[90] are duplicative of benefits from Gateway South. Energy Gateway has been part of the Company's long-term planning since 2007.[91] Originally, the project was designed to deliver reliability benefits not necessarily related to renewable resources. As parts of Energy Gateway have already been energized, reinforcement and reliability improvements have already been added to the system. As a result, Staff is concerned that the reliability benefits of Gateway South may be duplicative and is examining to what extent Gateway South is tied to Utah reinforcement. Staff is also investigating whether transmission alternatives or alternative timing and prioritization to Gateway South are more appropriate for this IRP.

The 2016-2017 NTTG Regional Transmission Plan found that B2H, EGS, portions of Gateway West, and Antelope projects are all part of the group's favored regional transmission plan of necessary resources to meet the group's projection of system need in 2026.[92] Staff is curious why IRP modeling does not show more benefits to transmission upgrades that have been described as necessary by regional transmission plans. Further analysis and information regarding the benefits of Energy Gateway

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[88] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 241.
[89] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 203.
[90] Segments B, Populus to Terminal, was energized in 2010 and Segment C, Mona to Oquirrh was energized in 2013.
[91] See PacifiCorp 2008 Integrated Resource Plan. Page 60. https://edocs.puc.state.or.us/efdocs/HAA/lc47haa93350.pdf.
[92] NTTG 2016-2017 Regional Transmission Plan. Page 4.

transmission projects and the impacts of changes in the relative timing of transmission investments is required before Staff can support the transmission plan in the 2019 IRP.

Recommendation:

- **In reply comments, the Company should address reliability benefits of Gateway South and the role of Gateway South in Utah reinforcement.**

Energy Gateway South

Staff is concerned that EGS may be receiving favorable treatment in this IRP as compared to other transmission resources. During the Public Input Meeting lead-up process, the assumed costs of the EGS line were adjusted downward[93] while also allowing it to be selected an additional year earlier, in 2024 as a proxy for year-end 2023.[94] The Company may have also removed the ability for the line to be selected after 2028, and Staff plans to submit discovery requesting more information on this issue. The EGS modeling changes resulted in EGS selection moving up from 2032 to 2023. No similar changes were made for any other Energy Gateway segment. Staff plans to investigate the assumed per-mile costs, and other modeling assumptions, used for EGS in comparison to other transmission segments in the 2019 IRP.

The selection of Gateway South is directly tied to the federal production tax credits (PTCs). Staff submitted discovery requests asking PacifiCorp to explain what Oregon ratepayers stand to gain with the addition of Gateway South, and repeatedly, the Company only mentioned benefits associated with new Wyoming wind and the associated tax credits. While the IRP mentions that there are some reinforcement and congestion benefits of Gateway South associated with forecasted wind generation,[95] in this IRP, the cost effectiveness of Gateway South is largely tied to wind resources and PTC value. Below are some answers from the Company when asked to define the benefits of Gateway South:

> Oregon, and all other state jurisdictions, will benefit from Energy Gateway South, and the accompanying new wind generation, by realizing lower present value system costs, inclusive of production tax credit benefits, relative to a scenario where Energy Gateway South and new wind is not added to the system at year-end 2023.[96]
>
> New wind resources that accompany the Energy Gateway South project will provide energy and capacity benefits (i.e., reduced net power costs and production tax credit benefits) that outweigh the total cost of the transmission line and new wind resources relative to a scenario that does not include Energy Gateway South and accompanying wind capable of providing system energy and capacity.[97]
>
> The Aeolus-to-Mona transmission line [Gateway South] and accompanying wind generation are added as an element of a broader resource portfolio to meet customer needs over time. The transmission line is needed to enable interconnection of the incremental new wind resources—the new wind cannot be added without the

[93] PacifiCorp's June 2019 Public Input Meeting Presentation. Page 6.
[94] PacifiCorp's July 2019 Public Input Meeting Presentation. Page 3.
[95] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 75.
[96] See PacifiCorp response to Staff Data Request 80, included in Attachment A to these initial comments.
[97] See PacifiCorp response to Staff Data Request 81, included in Attachment A to these initial comments.

> transmission, similar to other resources in the preferred portfolio that trigger incremental transmission upgrades…Proceeding with the Energy Gateway South line and accompanying wind in 2023 is a lower cost solution because the new wind can qualifying for production tax credits.[98]

In other words, the endogenous selection of Gateway South, and associated benefits, are directly tied to new wind generation in Wyoming. In the Company's own words, *"the new wind cannot be added without the transmission."* The Company did not cite reliability benefits of Gateway South when asked about the benefits of the project, nor did it cite congestion relief. Rather, the Company makes it clear that the value of Gateway South is tied to production tax credits and new Wyoming wind.

Because Wyoming wind is several states away from Oregon, Staff asked PacifiCorp in a Data Request to provide any existing analysis of Oregon's ability to import renewables from Wyoming without B2H in service. The Company stated that this sort of analysis is "beyond the scope of integrated resource planning."[99]

The Company has not shown definitively that Gateway South delivers benefits to Oregon ratepayers as compared to Gateway West and related transmission segments. Staff suggests that fewer miles of transmission build could translate to a cheaper solution, and Staff is not convinced that PacifiCorp's analysis has satisfactorily ruled out the possibility of savings from building the shorter B2H line instead of EGS.

Again, analysis and narrative to date fails to provide informative and necessary sensitivities that test the imminent necessity of Gateway South. The Company's analysis to date has provided little information to explain the expected usefulness of the EGS line, such as the expected quantity of transmission flows to Wyoming, and the amount of line use during times when westerly and southwesterly transmission flows are absent. For example, Staff is concerned that negligible flows to Wyoming and significant hours in a year without renewable generation from Wyoming could translate to a relatively expensive and underutilized transmission resource. More information is needed to better understand the expected utilization on each line considered in the 2019 IRP. Additional analysis with varying in-service-date sensitivities could also help to best identify system and Oregon-specific benefits.

Recommendations:

- **In reply comments, Staff requests PacifiCorp discuss why only one in-service date was considered for Segments E and H, and whether further analysis could provide more insight into the optimal timing for these segments.**
- **Staff would also like PacifiCorp to discuss in its reply comments which factors are making the economics of Energy Gateway South so favorable that it is chosen in each IRP portfolio. Are there specific low-cost resources enabled by Gateway South that could not be connected to B2H or other Energy Gateway segments? If so, is there a reason that similar resources could not cost-effectively be connected to B2H or other Energy Gateway segments instead?**

[98] See PacifiCorp response to Staff Data Request 88, included in Attachment A to these initial comments.
[99] See PacifiCorp response to Staff Data Request 77, included in Attachment A to these initial comments.

Boardman to Hemingway

In the 2017 Idaho Power Company IRP, the Oregon Commission acknowledged B2H construction.[100] It is unfortunate that PacifiCorp failed to include B2H as an endogenous transmission modeling option, since it would serve as a major artery enabling Wyoming wind to be exported to Oregon load and the Pacific Northwest. Staff questions whether PacifiCorp's Utah reinforcement projects, including Gateway South, have value for Oregon customers without B2H to connect them with Oregon load. Therefore, Staff cannot recommend acknowledgement of the projects at this time.

When Staff asked PacifiCorp why B2H was not included as an endogenous transmission option in the IRP in a data request, the Company stated that the B2H project requires two transmission paths linking three "bubbles" for proper representation, and therefore is too complex for endogenous selection in SO. Specifically, the Company claims that transmission paths from Borah to Hemingway, and from Hemingway to South-Central Oregon / Northern California are required. Additionally, PacifiCorp said 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."[101]

PacifiCorp's explanation of why B2H cannot be modeled endogenously seems counterintuitive. The Company seems to be evaluating B2H as a connecting resource to California, but B2H will facilitate connection between the Mona substation and Mid-C hubs, enabling bidirectional flows, and therefore does not need a path to California to estimate important project benefits. The Company's narrative appears to conflate Midpoint-to-Summer Lake flow with B2H, and appears to ignore the planned series compensation allowing for more differentiated flow across this path. Staff plans to investigate this claim further in order to understand why the Company views B2H as too complex to be viewed as a connection between two nodes.

In summary, the B2H line appears to be a simple connection between two System Optimizer nodes, and Staff has not yet heard a thorough explanation of why PacifiCorp cannot allow it to be selected endogenously.

In Staff's opinion, the Company's very limited analysis of B2H calls into question whether major transmission investments were evaluated on consistent and comparable basis. Staff would be highly interested in seeing analysis that reverses the order of the construction of projects, allowing PTC wind to be constructed closer to Oregon load along with the shorter B2H line in 2024. Charting of projected line utilization in both directions would also be helpful for Energy Gateway and jointly planned line segments. Staff would like to work with the Company to investigate the possibility of obtaining information showing actual current flows, and how those flows are projected to change in each direction with each additional segment of Energy Gateway on an hourly basis, across a calendar year, and in aggregate by summing line flows in both directions.

Conclusion

The burden rests on PacifiCorp to demonstrate the benefits of Gateway South and Utah reinforcements to Oregon customers, and Staff cannot recommend acknowledgment of this project until the Company demonstrates these benefits. The Company has failed to sufficiently assess arterial transmission projects

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[100] See Order No. 18-176. Pages 9-11.

[101] See PacifiCorp response to Staff Data Request 91, included in Attachment A to these initial comments.

recognized and acknowledged by the Commission (B2H), while seeming to place favorable assumptions on projects that reinforce reliability in other states (Energy Gateway South).

Recommendation:

- **Staff requests PacifiCorp provide a charting of projected line utilization in both directions for Case P-26 (with EGS and B2H), for P-45CNW (preferred portfolio), and for P-45CP (preferred portfolio plus Dave Johnston wind in 2027). Information requested includes a depiction of actual current flows, and how those flows are projected to change in each direction with each additional segment of Energy Gateway on an hourly basis, across a calendar year, and in aggregate by summing line flows in both directions.**
- **PacifiCorp should report on the possibility of completing B2H in 2024 to pair with PTC wind near to the Western BAA.**

7.3 REGIONAL TRANSMISSION NEED

It is unfortunate that PacifiCorp is only able to model Eastern transmission endogenously in SO and has only included B2H as an after-the-fact sensitivity, when over a decade of study has demonstrated that Gateway South is a lower-priority project than B2H. In the Pacific Northwest, PacifiCorp has participated in the Northern Tier Transmission Group (NTTG) for Federal Energy Regulatory Commission (FERC) Order 1000 regional planning compliance. As a result, the Company has contributed to biennial planning studies to determine regional transmission needs. Staff has also participated in these groups in the past. The regional studies generally forecast load ten years into the future, design stress-test cases, and mix and match various transmission lines under different scenarios. The plans then identify a number of regionally significant transmission projects that solve contingencies. The studies began in 2007 and have evolved over time. Transmission projects have come and gone, and project sponsors have also changed over time. Below is an NTTG map from 2017 that shows one scenario where transmission issues are likely to arise in the West if upgrades are not made by 2026:

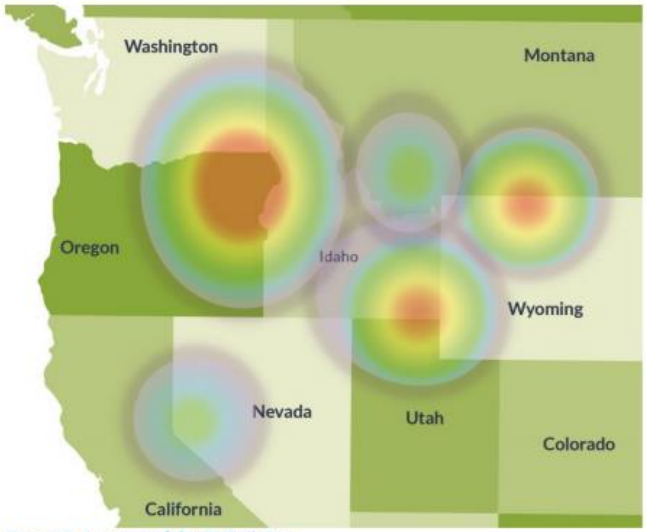

Figure 10. Heat map of the D2-Null Case. [102,103]

Staff has reviewed the studies and has consulted with other internal Staff experts in order to assess the regional significance of Energy Gateway and in particular Gateway South as opposed to other transmission options. It is important to note that initially, NTTG assumed B2H would be built prior to any of the Energy Gateway projects with the exception of Gateway Central.[104] While other elements of Energy Gateway have also been considered regionally significant for solving contingencies, it is important to note that in the 2015 regional plan, B2H was identified as the most important project that could solve regional contingencies along with an alternate transmission project that only included certain segments of Energy Gateway.[105]

Notably, the 2015 plan tested a sensitivity in which it removed B2H, but included the rest of Energy Gateway. Though this case was able to solve contingencies, it was not selected as the most cost effective. The more recent 2017 and 2019 plans test many more cases with (and without) B2H. In fact, B2H is the most-tested project across all scenarios. Case CC1 in both the 2017 and 2019 plans include B2H without any other major transmission projects. Consistently, B2H helps solve contingencies and does not depend on additional wind PTCs for cost-effectiveness.

The value of B2H can also be tied to its role as a connecting point between the Mid-Columbia power hub and the Mona substation, allowing not only PacifiCorp, but also Idaho Power and Bonneville to utilize it

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[102] NTTG 2016-2017 Regional Transmission Plan. https://nttg.biz/site/index.php?option=com_docman&view=download&alias=2948-nttg-2016-2017-regional-transmission-plan-final-12-28-2017&category_slug=2016-2017-regional-transmission-plan-final&Itemid=31 p 7.

[103] NTTG 2016-2017 Regional Transmission Plan. https://nttg.biz/site/index.php?option=com_docman&view=download&alias=2948-nttg-2016-2017-regional-transmission-plan-final-12-28-2017&category_slug=2016-2017-regional-transmission-plan-final&Itemid=31 p 7.

[104] Populus to Terminal (Segment B) was energized in 2010 and Mona to Oquirrh (Segment C) was energized in 2013. The Regional Plans from 2007, 2009, and 2011 all show B2H as a project constructed before most of Energy Gateway.

[105] One of these projects was Energy Gateway Segment D.2, which is already under construction.

as a long-term resource. This allows three entities to split the cost, create a channel for bulk electric system connectivity, allow for blending diverse resources as a "many-to-many"[106] bidirectional resource, increase access to markets, and fill a unique regional role. The rest of Energy Gateway does not do this. PacifiCorp makes clear that Gateway South is driven by the assumed expiration of wind production tax credits for projects beginning construction in 2019 and will alleviate contingencies related to increased wind production. Gateway South is not a many-to-many resource. It does not connect two hubs. It will be wholly owned by PacifiCorp (i.e., the costs are not shared), and its primary purpose is to facilitate Wyoming wind, not serve as a bidirectional regional resource.

In regional planning, B2H is always selected as part of the NTTG Regional Plan, usually (but not always) along with the rest of Energy Gateway,[107] including Gateway South. It is Staff's opinion that Gateway South is an inferior resource compared to B2H from an Oregon ratepayer perspective. Regionally, the ability to move low-cost hydro power or wind and add connectivity between two market hubs contributes substantially to the flexibility value of B2H as compared to the rest of Energy Gateway.

It is well-known that transmission has long lead times, is expensive, and faces significant regulatory hurdles. The Company must explore modeling options consistent with regional planning, in-service dates, costs, and benefits. Staff acknowledges that other components of Energy Gateway have also been core projects of regional planning. However, B2H is the only unconstructed project to have been acknowledged by the Oregon Commission. It is incumbent on the Company to produce analysis that gives the full breadth of transmission topology and its impacts on Oregon ratepayers.

Generally, Staff is concerned that including EGS in the IRP preferred portfolio, but not including other Energy Gateway resources, results in portfolios that are not optimized around these resources existing in the future. Instead, portfolios are optimized for a future in which resources including B2H do not exist. Staff's concern is that if the entire Energy Gateway project is truly needed, then planning around a future without the entire project is likely to result in sub-optimal portfolios.[108]

One potential way to address this issue would be through RFP scoring. If the EG resources are likely to be deemed cost-effective in the future, as PacifiCorp indicates, PacifiCorp's RFP should reward bids that perform well in a future with a full EG buildout.

Recommendations:

- **Staff would like PacifiCorp's reply comments to address regional needs for western transmission projects, and explain why PacifiCorp's analysis in the SO model does not show net benefits to PacifiCorp customers from B2H, even though the NTTG transmission studies indicate that it will be an important part of resolving transmission issues in Oregon by 2026.**
- **Staff also requests PacifiCorp discuss the likelihood that the entire Energy Gateway project could be required by FERC interconnection or transmission service rules in the near term. If**

[106] This phrase is more commonly used in software systems analysis, but it is a useful metaphor. Another example of a "many-to-many" relationship is in a university with many students and many classes. Each student can enroll in a large number of classes. Each class might have a large number of students. Likewise with transmission systems, many-to-many relationships can exist between customers and suppliers of electricity.
[107] For example, in the 2015 plan, Energy Gateway Segment E was not listed as a core regional plan component.
[108] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 81.

this is likely to be the case, then the question of whether PacifiCorp Oregon customers should plan for these resources should be discussed, beginning in this IRP cycle.

- **Staff would like PacifiCorp to provide more explanation in reply comments as to how and why the Energy Gateway transmission projects' regional value, as shown in recent NTTG studies, has not been captured in IRP modeling. If the projects are needed for reliability in the region, but are not part of a least cost, least risk portfolio for PacifiCorp customers, then that may be an important conversation for PacifiCorp and the Commission to have in the near term.**
- **Staff would like PacifiCorp to provide a comparison of the cost, location, and capacity of generation resources selected in the action plan timeframe of the full EGS buildout case (P-25) as compared to the preferred portfolio.**
- **The Company should explain whether it would support the addition of a RFP scoring metric for a bidding resource's performance in the most probable EG buildout future.**

7.4 ADDITIONAL QUESTIONS

Staff is continuing to look into the following with regard to transmission in the IRP:

- Should PacifiCorp include the option for its System Optimizer model to select resources located off of PacifiCorp's system that require wheeling for delivery to customers? Would this open up better sites for renewable generation or help make the expectations for RFP bidders with off-system projects clearer or more transparent?
- Staff is concerned about the differences in the quantity and location of new generation between portfolios with the full Energy Gateway buildout and those that install Segment F only. Based on PacifiCorp's maps and workpapers, there appear to be relatively few changes in the timing and location of resources, even when hundreds of MW of east to west transfer capacity are added.[109] PacifiCorp should explain how it is allowing the new resources to be modeled as connecting with the new transmission segments.

  Recommendation:

  - **Staff requests an explanation of how new resources are assumed to connect to the future Energy Gateway transmission lines (segments D.1, D.3, E, F, and H), what new resources are able to utilize the new capacity on these lines, and whether wheels are assumed to be required.**

- Why has the Company failed to incorporate estimated wheeling revenues in assessing the benefits of Energy Gateway, including B2H?[110]
- In a newly-issued FERC Order in Docket ER19-2760-000, FERC rejected proposed tariff revisions related to regional planning compliance. FERC indicated it wants a fair opportunity for transmission developers like LS Power to be able to propose projects in response to identified transmission needs and then to allocate costs of said independent projects to IOUs and their

[109] See resource maps for P-45CNW and P-25 on pages 279 and 383 of Volume II of the 2019 IRP. Appendix M.
[110] See PacifiCorp response to Staff Data Request 87, included in Attachment A to these initial comments.

ratepayers. This will have an impact on regional transmission planning and potential costs to Oregon customers.

Recommendation:

- **The Company should address the particulars of this newly-issued FERC Order in Docket ER19-2760-000 and clarify if and how transmission segments seeking acknowledgement within an Action Plan now would still be the best (i.e., least cost and risk.) The Company should also discuss maximum benefits as compared to alternative proposals that could come from entities like LS Power and affiliates, National Grid, or Next Era. PacifiCorp may also wish to discuss how the Company's planning, construction, and operations would control costs and better explain the relative risks of a PacifiCorp built and operated line vs. an independently built and operated alternative but similar transmission solution.**

8. REGIONAL CAPACITY ADEQUACY, FRONT OFFICE TRANSACTIONS

8.1 REGIONAL CAPACITY ADEQUACY AND MARKET PURCHASES

In its 2019 IRP, the Company relies on the NERC Long Term Reliability Assessment (LTRA) to analyze the adequacy of the western power market to support the volumes of purchases that the Company plans to reply on.[111, 112] The Public Service Commission of Utah directed the Company to use the Western Electricity Coordinating Council (WECC) as a source for this evaluation.[113] The Company has used the WECC Power Supply Assessment in the past; however, because the report was not updated in time for the IRP, it relied on the NERC LTRA. Staff is exploring whether it would be beneficial for the Company to consider multiple reliability assessments in this and future IRPs.

Table J.6 shows that the reserve margin in portions of the WECC is expected to fall below the NERC 'reference reserve margin' by 2028, even if prospective new resources in the region begin service as expected. Prospective resources are defined as those that have been requested but not approved, do not have firm transmission contracts, or are not certain to be available at peak.[114] The NERC 'reference reserve margin' is on average about 15.5 percent across the WECC from 2019 to 2028. In 2028, the shortfall of 0.9% in the Rocky Mountain Reserve Group (RMRG) represents a reserve margin of 14.4%.[115]

[111] PacifiCorp 2019 Integrated Resource Plan. Volume II. Appendix J. Page 147.
[112] North American Electric Reliability Corporation 2018 Long Term Reliability Assessment, www.nerc.com/pa/RAPA/ra/Pages/default.aspx
[113] *Id*.
[114] PacifiCorp 2019 Integrated Resource Plan. Volume II. Appendix J. Page 148.
[115] PacifiCorp 2019 Integrated Resource Plan. Volume II. Appendix J. Page 149.

Table J.6 -- Planning Reserve Margin Shortfalls by Subregion with Prospective Resources

Shortfalls Assuming Prospective Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
NWPP	Summer	8.1%	6.4%	5.3%	3.3%	4.5%	4.3%	4.4%	4.5%	7.4%	3.1%
RMRG	Summer	16.9%	9.8%	8.4%	7.1%	5.4%	4.0%	2.6%	1.5%	0.4%	**-0.9%**
SRSG	Summer	18.5%	17.3%	16.0%	12.8%	9.8%	7.8%	5.7%	4.2%	1.2%	**-0.2%**
CA/MX	Summer	20.2%	31.0%	30.0%	30.8%	31.9%	28.1%	27.8%	28.4%	28.2%	27.7%

[116]

While the NERC analysis looks at regions individually, Staff notes the high planning reserve margin in California and the possibility that transfers from California could support peak load in nearby regions.

Additionally, the Pacific Northwest Power Supply Adequacy Assessment for 2021 concluded that the Pacific Northwest is expected to be resource adequate only through 2021, based on existing resources and those that are already sited and licensed.

In the preferred portfolio, PacifiCorp's Western BAA is assumed to serve an average of 192 MW of peak winter demand with energy purchased from the market or bilateral contracts between 2021 and 2026. Staff finds that this level of market reliance is probably reasonable but is continuing to investigate market depth assumptions.

Staff needs to better understand how the FOT limits were developed for the 2019 IRP. These assumptions play an important role in the IRP modeling not only from a resource adequacy perspective, but also because they can influence the quantity of resources that must be built by PacifiCorp. If more energy is assumed to be available at market, then fewer resources need to be built by the Company, and vice versa. Staff has submitted information requests on assumed FOT limits, and will report findings in final comments.

Capacity Additions on PacifiCorp's System

The preferred portfolio contains no new capacity additions in the west until 2024, when 124 MW of battery and 895 MW of solar in Oregon and Washington are selected. By comparison, 325 MW of nameplate capacity are installed in the East before 2024.

Recommendations:

- **Staff would like PacifiCorp to address in its reply comments whether the lack of any new additions in the west is a safe and reliable outcome, given the recent forecasts of regional WECC capacity deficit if no new resources are built in the region.**
- **Additionally, given the several hundred MW of QF projects currently scattered around various load pockets in Oregon and unable to interconnect, Staff would like PacifiCorp to explain what transmission investments and queue management reforms underlie the assumption that 895 MW of solar with 124 MW of battery can be built and online in Oregon and Washington by 2024 without also addressing existing transmission and interconnection bottlenecks.**

[116] PacifiCorp 2019 Integrated Resource Plan. Volume II. Appendix J. Page 150.

9. RELIABILITY AND EMERGING TECHNOLOGIES

9.1 RELIABILITY

The Company added a "reliability assessment phase" to its portfolio processing for the 2019 IRP, utilizing the Planning and Risk model to assess reliability on an hourly basis for each year from 2023 through 2038.[117] The reliability assessment phase is a critical component of PacifiCorp's IRP portfolio development, as it accounts for potential reliability shortfalls that could otherwise result from intermittent variable resources replacing dispatchable resources that have more flexibility.[118]
Staff appreciates this analysis and will continue to evaluate reliability modeling assumptions in IRP portfolios, including the incremental 500 MW of "capacity in excess of hourly shortfalls" added to 2019 IRP portfolios.[119] This requirement appears to be incremental to the 13 percent planning reserve margin, and it represents reserves held for contingency, forecast error, and intra-hour variability in typical PacifiCorp operational experience.[120] Staff will seek to understand why the 13 planning reserve margin is not itself sufficient to account for required operating reserves. Staff also looks forward to continuing analysis of power flows and other aspects of reliability on PacifiCorp's system.

With regard to reliability, Staff is particularly interested in learning more about how the Company will consider the Western Interconnection Reliability Coordinator (RC) transition from PEAK to California ISO (CAISO) in the 2019 IRP, and whether any impacts from this change are reflected in the reliability assessment.

The RC oversees grid compliance with federal and regional grid standards, and can determine measures to prevent or mitigate system emergencies in day-ahead or real-time operations.[121] The RC also provides regional leadership in system restorations after major events.[122] The Western Interconnection had a single RC, PEAK, that dissolved in Q4 of 2019. NERC has been working to certify five RCs to replace PEAK RC.[123]

The CEO of the NERC has stated that this transition from a single RC to five in the expansive footprint of the Western Interconnection is the "single largest risk of reliability in front of us." PacifiCorp is located in the RC West reliability coordinator area. NERC certified CAISO as the RC for this area. [124] CAISO will be governed by a membership-based RC West oversight committee that will give guidance and build

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[117] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 173.
[118] *Id*.
[119] PacifiCorp's April 25, 2019 Public Input Meeting Presentation. Page 40.
[120] PacifiCorp's response to Staff Feedback Form submitted on July 11, 2019.
[121] California ISO, *Reliability Coordinator Frequently Asked Questions,* available at https://www.caiso.com/Documents/ReliabilityCoordinatorFAQ.pdf.
[122] *Id*.
[123] Utility Dive, *NERC CEO: Western RC Transition is the "single largest risk to reliability in front of us"*, June 27, 2019, available at https://www.utilitydive.com/news/nerc-ceo-western-rc-transition-is-single-largest-risk-of-reliability-in-f/557719/.
[124] California ISO, *Reliability Coordinator Frequently Asked Questions,* available at https://www.caiso.com/Documents/ReliabilityCoordinatorFAQ.pdf.

consensus on reliability compliance, including a common understanding of NERC standards.[125] Additionally, CAISO will have working groups to address topics that require coordination among the five RCs, including operations planning, seams management, data sharing, emergency preparedness, and training.[126]

Given the changes for the Western Interconnection during this transition, Staff will continue to explore how PAC plans to both participate in these working groups and incorporate these shifting approaches in its reliability inputs as the Western RC transitions from a single Reliability Coordinator to five. Staff continues discovery regarding the Company's assumptions and would like to see analysis from the Company addressing these concerns.

9.2 SMART GRID

OPUC Staff appreciates the Company including an appendix for the smart grid that PacifiCorp has been investing in. One prominent investment has been in advanced metering infrastructure (AMI), but this does not get much treatment in Appendix E of the 2019 IRP beyond Oregon.

OPUC Staff is concerned about how up-to-date the 2019 IRP's description of synchrophasor grid integration is when it states: "These devices are currently collecting data and will support PacifiCorp's and Peak Reliability's goal of maintaining power system stability."[127] The 2019 IRP goes on to say: "Once Peak Reliability has their advanced application functionality enabled, which is expected in 2017, PacifiCorp expects to reinitiate data flow to Peak Reliability."[128] The announcement of Peak Reliability shutting down operations preceded the filing of PacifiCorp's 2019 IRP, as of course did the year 2017.

Recommendation:

- **Staff would like PacifiCorp to describe in the Company's reply comments how the benefits of the Western Interconnection Synchrophasor Project are expected to continue with Peak Reliability's successor.**
- **Staff would like the Company to explain in its reply comments what benefits PacifiCorp expects to gain from AMI throughout its multistate system.**

[125] *Id*.
[126] *Id*.
[127] PacifiCorp 2019 Integrated Resource Plan. Volume II. Appendix E. Page 75.
[128] *Id.*

10. NEW RESOURCES AND RETIREMENTS IN THE 2019 IRP PREFERRED PORTFOLIO AND ACTION PLAN

10.1 PREFERRED PORTFOLIO

PacifiCorp's preferred portfolio consists of a set of about 5.2 GW of new resources in the action-plan timeframe that include demand response, energy efficiency, wind, and solar plus storage:

Table 5 – Energy Resources in Action Plan Window

	Resource	2019	2020	2021	2022	2023	2024
East	Wind, UT	-	-	-	-	69	-
	Wind, WYAE	-	-	-	-	-	1,920
	Total Wind	-	-	-	-	69	1,920
	Utility Solar+Storage - PV - Utah-S	-	-	-	-	-	231
	Utility Solar+Storage - PV - Utah-N	-	-	159	64	3	674
	Total Solar	-	-	159	64	3	904
	Demand Response, UT-Cool/WH	4.1	-	7.0	-	9.9	-
	Demand Response, UT-Ancillary Services	-	-	-	-	8.3	-
	Demand Response Total	4.1	-	7.0	-	18.1	-
	Energy Efficiency, ID	6	6	6	7	7	7
	Energy Efficiency, UT	58	67	67	68	69	68
	Energy Efficiency, WY	10	10	11	14	15	16
	Energy Efficiency Total	74	83	85	88	92	92
	FOT East - Summer	-	-	-	-	-	-
West	Utility Solar+Storage - PV - Jbridger	-	-	-	-	-	354
	Utility Solar+Storage - PV - S-Oregon	-	-	-	-	-	500
	Utility Solar+Storage - PV - Yakima	-	-	-	-	-	395
	Total Solar	-	-	-	-	-	1,249
	Energy Efficiency, CA	1	2	2	2	2	2
	Energy Efficiency, OR	40	37	37	42	41	46
	Energy Efficiency, WA	11	10	10	11	12	12
	Energy Efficiency Total	52	49	48	55	55	59
	FOT West - Summer	998	719	493	503	498	131
	FOT West - Winter	151	131	268	303	314	44 [129,130]

However, PacifiCorp's All Source RFP Action Item does not mention the specific type, location, or size of resources to be acquired. Instead it consists of a schedule for a 2020 RFP for resources of unspecified type, location, and size. Staff is concerned about the lack of parameters from the preferred portfolio in

[129] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 214.
[130] In the 2019 IRP, resources selected in 2024 are often viewed as a proxy for year-end 2023. See page 213 of 2019 IRP

the action plan, given the requirement in the Oregon IRP guidelines that the action plan reflect the preferred portfolio.[131]

10.2 ALL SOURCE RFP ACTION ITEM:

PacifiCorp's All Source RFP Action Item is as follows:

- PacifiCorp will issue an all-source request for proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2023.
- By the end of Q4 2019, file a request for interconnection queue reform with the Federal Energy Regulatory Commission (FERC) and make state filings to initiate the process of identifying an independent evaluator.
- In Q1 2020, file a draft all-source RFP with the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, as applicable.
- In Q2 2020, receive approval from FERC to reform the interconnection queue.
- In Q2 2020, receive approval of the all-source RFP from applicable state regulatory commissions and issue the RFP to the market.
- In Q3 2020, identify a preliminary final shortlist from the all-source RFP and initiate transmission interconnection studies consistent with queue reform as approved by FERC.
- In Q2 2021, identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon, file, certificate of public convenience and necessity (CPCN) applications, as applicable.
- By Q2 2022 execute definitive agreements with winning bids from the all-source RFP.
- By Q4 2023, winning bids from the all-source RFP achieve commercial operation.

Lack of Specifics in All Source RFP Action Item

Staff has a few concerns about this action item. One concern is the lack of specificity in terms of the quantity or type of resources that might be procured. An action item more clearly aligned with the quantity and general type of resources from the preferred portfolio in the IRP would provide a more structured and meaningful Action Item for the Commission to consider acknowledging. The action item should provide information about the maximum quantity of resources that will be procured through the RFP, as well as the type of resource (energy or capacity).

Recommendation:

- **PacifiCorp should submit an updated action item with an approximate quantity and type (energy or capacity) of the resource(s) that it will seek to acquire.**

Queue Reform

While Staff is supportive of queue reform in general, Staff is continuing to consider the elements of PacifiCorp's queue reform proposal. Staff would like to be clear that, while it recommends

[131] Order No. 07-002, Appendix A, Guideline 4.

acknowledgement of PacifiCorp's pursuit of queue reform in the near term, Staff recommends that any Commission acknowledgement of the RFP Action Item should state explicitly whether it is intended to acknowledge queue reform generally, or the specific elements of PacifiCorp's queue reform request with FERC.

Additionally, Staff is uncertain from the language of the RFP action item whether queue reform would be enacted in time for it to influence the outcome of the RFP. Therefore, Staff would like the Company to address in its comments how PacifiCorp expects that queue reform would influence the RFP.

Recommendations:

- **Staff requests PacifiCorp explain in reply comments whether it plans for queue reform to influence its next planned RFP or if queue reform would only apply to future RFPs. Staff also requests a discussion of how PacifiCorp's queue reform might change the RFP process.**
- **Staff requests a workshop for PacifiCorp to share the details of its queue reform proposal with Staff and stakeholders.**

RFP Implementation

PacifiCorp chose not to provide information about RFP design, modeling, or price and non-price scoring details in the 2019 IRP in sufficient detail to avoid further process before issuing a draft RFP. Staff observes that the IRP generally is the docket in which a significant number of stakeholders participate in an in-depth review of the utility's modeling and RFP design. When a utility intends to issue an RFP within a year of IRP acknowledgment, and likely has the necessary information regarding the RFP, the most efficient and effective process available for review of the RFP elements is the IRP docket.

When the information is not included in the IRP, according to the Oregon competitive bidding rules, this means the Company must file this information in a separate filing in advance of filing the draft RFP.[132] A separate review process that provides for the same sort of notice and review as the IRP must be conducted in the IE selection docket.[133] Review of such information in the IRP or IE selection proceedings allows for meaningful review and in-depth discussion by stakeholders, and ensures the review is sufficient to effect the purpose of the competitive bidding rules, which is to "establish a fair, objective, and transparent competitive bidding process, without unduly restricting electric companies from acquiring new resources and negotiating mutually beneficial terms."[134] This allows for a more efficient process for review of the draft RFP.[135]

Staff understood an announcement by PacifiCorp at the most recent Public Input Meeting to indicate that the Company is considering using a different set of planning models to score bids in the RFP than was used to model portfolios in the IRP. Staff notes that this change would make a thorough review of the RFP more complex. Staff notes that the amount of time required to sufficiently review a new modeling methodology could be more substantial than the time required to review scoring metrics. The

[132] OAR 860-089-0250 (2)(a).
[133] Order No. 18-324 p. 8. "If a utility chooses to deviate from the scoring proposed in the RFP (sic), the same sort of notice and review should be available to all stakeholders."
[134] OAR 860-089-0010(1).
[135] OAR 860-089-0250(5), (6).

time required would increase if the new software resulted in substantial changes to the type and quantity of new resources selected in the action plan timeframe.

We expect PacifiCorp to provide RFP details within a reasonable timeframe before the draft RFP may be filed, allowing bidders and stakeholders to consider the price and non-price scoring metrics, and other required elements with the same notice and review by interested parties as in the IRP. PacifiCorp should confirm whether it is planning on a thorough review of RFP design, modeling, and scoring in a filing in the IE selection docket prior to filing a draft RFP.

Recommendation:

- **PacifiCorp should explain why the RFP design, scoring, and modeling was not identified in the IRP, whether these elements are anticipated to be used in the RFP, and confirm whether it is planning on a separate filing that allows for a thorough review by interested stakeholders in the IRP or IE selection docket prior to filing a draft RFP that will allow for the same review as in the IRP.**

Transmission in the RFP

In the 2019 IRP, PacifiCorp has modeled all new generation resources as located within or near to its service territory. Therefore, the IRP does not provide much insight into how PacifiCorp will model transmission wheeling costs for resources in the RFP if those resources are not connected to PacifiCorp's transmission system. Further, adding geographic diversity to PacifiCorp's portfolio of renewable resources could represent a resiliency/reliability benefit to the system.

Recommendations:

- **Staff requests that in reply comments PacifiCorp provide an explanation of how these wheeling costs will be modeled in the next RFP.**
- **Staff requests PacifiCorp consider in its reply comments whether adding a geographic diversity scoring metric to the RFP could help improve the value of new resources to PacifiCorp's system.**

10.3 COAL RETIREMENTS IN THE ACTION PLAN

The Existing Resources action item focuses on coal retirements included in the preferred portfolio, as well as the conversion of Naughton unit 3 to gas in 2020:

Table 6 – Coal Retirements in Action Plan

Unit(s)	2019 IRP	2017 IRP	PAC Share of Capacity (MW)
Naughton 3 Retirement	2020	2029	-280
Naughton 3 Gas Conversion	2020	N/A	247
Cholla 4 Retirement	2023	2020	-387
Jim Bridger 1 Retirement	2023	2037	-351
Naughton 1,2 Retirement	2025	2029	-357
Craig 1 Retirement	2025	2034	-82

Staff finds that these early retirement dates are generally reflective of coal study findings, which showed Naughton, Jim Bridger, and Craig units to be among those with the greatest potential benefits from early retirement.[136]

Case	Inc. Retired Capacity in 2023 (MW)	PVRR(d) (Benefit)/Cost of Early Retirement ($m)	Naughton 1	Naughton 2	Bridger 1	Bridger 2	Hayden 1	Hayden 2	Craig 1	Craig 2	Dave Johnston 3
C-34	357	($123)	✓	✓							
C-35	711	($211)	✓	✓	✓						
C-36	510	($158)	✓		✓						
C-37	554	($143)	✓		✓		✓				
C-38	755	($120)	✓	✓	✓		✓				
C-39	834	($52)	✓	✓	✓		✓			✓	
C-40	1,193	($191)	✓	✓	✓	✓	✓			✓	
C-41	1,529	($12)	✓	✓	✓	✓	✓	✓	✓	✓	✓
C-42	1,063	($248)	✓	✓	✓	✓					
C-43	928	($31)	✓	✓	✓						✓

[137]

There are several reasons the IRP results differ somewhat from the results of the stacked coal study. First, PacifiCorp's IRP portfolios consider reliability studies in PaR for each year from 2023 through 2038, while the coal study only assessed reliability in three representative years.[138] Fully accounting for the reliability impacts of coal unit retirements has an incremental cost which can reduce the number of early retirements that can be achieved at a savings to customers. Several other modeling assumptions, discussed in PacifiCorp's Public Input Meeting presentations, have also changed since the coal study.[139]

[136] Docket No. LC 70. PacifiCorp's May 16, 2019 filing of Stacked-Retirement Summary Results. Page 8.
[137] Docket No. LC 70. PacifiCorp's May 16, 2019 filing of Stacked-Retirement Summary Results. Page 8.
[138] See the April 25, 2019 Public Input Meeting presentation.
[139] See the June, July, and September 2019 Public Input Meeting presentations for a summary of the changes.

Staff has a few concerns and areas for further investigation regarding the existing resources actions in the Action Plan, including retirement assumptions for Cholla 4 and coal retirement community impact planning.

Cholla 4

Staff commends PacifiCorp's recent announcement that it will close Cholla 4 in 2020. This date was shown to create cost savings for customers and the potential delay until 2023 was surprising given that Staff notes that Cholla 4 was modeled as retiring in 2020 as early as the the 2017 IRP.[140] A delay until 2023 would have caused excess expense for customers, and Staff's position is that a delay of three years would not reflect prudent operation of that unit.

Moving forward with economic retirements, PacifiCorp should be prepared to achieve the most cost-effective retirement date for each unit.

Recommendations:

- **PacifiCorp should make its best estimate of when Cholla will actually retire, and use that date in any upcoming RFP analysis. Additionally, if the Company has new information about any unit, it should use that updated retirement date in the RFP.**
- **For coal retirements modeled as cost effective in a given year, PacifiCorp should actively pursue the actions in its action plan toward achieving the cost-effective retirement date. Otherwise the company risks eroding the customer benefits associated with the retirement dates found to be cost effective through the IRP analysis.**

Jim Bridger

Staff would like to point out that retirement of Jim Bridger 3 or 4 in 2023 is likely to result in greater cost savings than retirement of unit 1 or 2. This is because Units 3 and 4 have additional costs associated with running pollution-reduction equipment (Selective Catalytic Reduction or SCR).

Staff understands that PacifiCorp's plan to shut down units 1 and 2 and leave units 3 and 4 running until 2037 would not require SCR installation, whereas PacifiCorp could be required to install SCR equipment on units 1 and 2 in 2021 and 2022 if they continue to run.[141] However, Staff is curious as to whether SCR will be necessary at any point on units 1 and 2, given their planned operations, whether it is possible the Wyoming Department of Environmental Quality would allow units 1 and 2 to operate as late as 2037 without SCR, while shutting down units 3 and 4 at the Jim Bridger site. This would create more savings for ratepayers, while still greatly reducing emissions of Regional Haze pollution at the Jim Bridger site.

10.4 CUSTOMER PREFERENCE RESOURCES AND RFP

Customer Preference Resources

The 2019 IRP includes thoughtful consideration of the role that voluntary customer actions will play in meeting the Company's long-term resource needs. The IRP does not specify which programs, policies,

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[140] LC 67. PacifiCorp 2016 Integrated Resource Plan. Pages 195-196.
[141] PacifiCorp 2017 Integrated Resource Plan. Volume I. Page 20.

and other actions PAC considers within the category of customer preference acquisitions; however, the IRP mentions Utah's Community Renewable Energy Act (H.B. 411), which created an opportunity for municipalities and counties to achieve a net-100% renewable energy portfolio by 2030, and Oregon's Senate Bill (SB) 1547 Community Solar Program (CSP), which allows utility customers to own or subscribe to a portion of a solar facility located anywhere in the utility's Oregon service area.

Staff finds that this is an increasingly important consideration given the proliferation of corporate and community decarbonization goals, continued accessibility of carbon-free technologies, and evolution of state policies and utility programs. In the 2019 IRP, PAC modeled base, high, and no customer preference resource acquisition scenarios. Staff is currently reviewing the assumptions and methodology underlying these scenarios and notes two specific areas of interest identified to date.

Staff's first area of interest relates to the S-08 High Customer Preference Sensitivity on the preferred portfolio, which "assumes proliferation of customer preference resources at higher levels than anticipated with close to 9,300 GWh of customer preference resources being added by the end of the twenty-year planning period."[142] The sensitivity analysis suggests that high customer preference activity creates a $22 million benefit over the base case.[143] Further, PAC indicates that this sensitivity assumes customer preference acquisitions in both Oregon and Utah.[144]

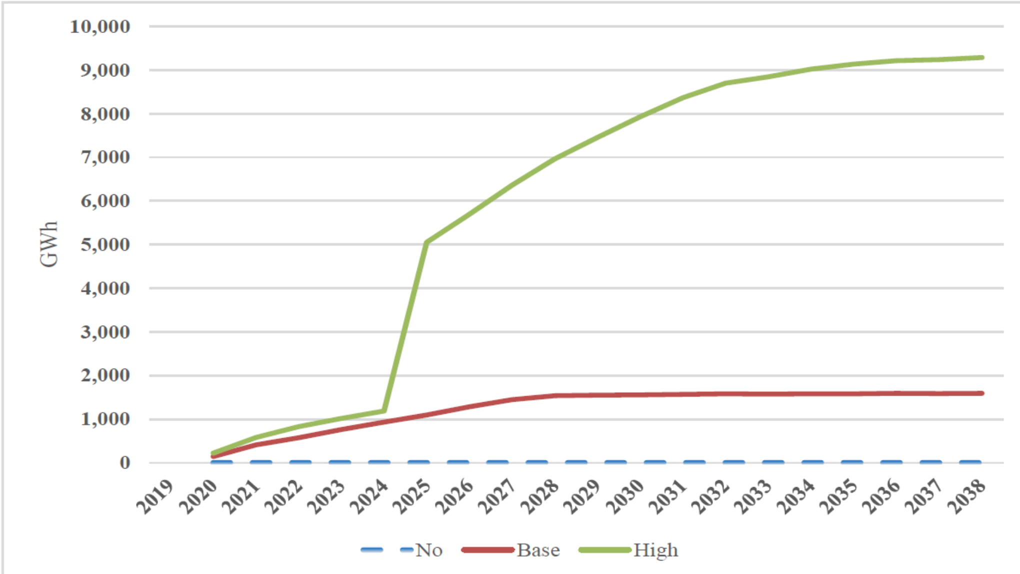
Given the benefits identified from a high customer preference scenario, Staff is interested in PAC's strategy to enable customer preference resource acquisitions in Oregon. Staff is curious if PAC plans to file a voluntary renewable energy tariff (VRET) in Oregon under the guidelines set forth in Commission Order No. 15-405, or if PAC is considering other mechanisms to allow the Company to acquire resources on behalf of specific customers in Oregon? Staff further notes its discomfort with the manner in which PAC acquires long-term PPAs with generating facilities in order to satisfy specific customers' preference for RECs from these facilities under the Schedule 272 Blue Sky offering.[145] This approach seems to allow the Company to make long-term resource procurement decisions on behalf of individual customers outside of the IRP and without the transparent process and various protections provided by the VRET.

Recommendation:

- **Staff requests that PAC explain in reply comments its strategy to provide customer preference options in Oregon, and whether it plans to file a VRET in Oregon.**

[142] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 206.
[143] PacifiCorp 2019 Integrated Resource Plan. Volume I. Page 270.
[144] PAC Response to Sierra Club IR No. 4.1, subpart (a).
[145] Docket No. LC 70. Staff's Comments on PacifiCorp's September 27, 2019 Notice of Exception to the Competitive Bidding Rules. October 25, 2019.

Figure 12 - Generation Requirements for Customer Preference Sensitivities



Staff's second area of interest relates to the Oregon CSP. Under the CSP, PAC is required to take the output from subscribed CSP projects. Further, the Commission requires that, "[w]hen assessing load-resource balances in its integrated resource planning, an electric company must include forecasts of market potential for community solar projects and analyses comparing historical forecasts and actual community solar project development."[146] The CSP will launch in Q1 2020 and, under the current Commission guidance, could add between 32 and 64 MW of new solar generation in PAC's Oregon service territory.[147] PAC's 2019 IRP does not appear to address the generation associated with the CSP or the requirement to account for the CSP when assessing the load-resource balances.

Recommendation:

- **Staff requests that PAC explain how the Oregon CSP is accounted for in its IRP modeling and how it has complied with Commission direction to forecast the impact of CSP on its load-resource balances.**

Customer preference RFP Action Item:

PacifiCorp's 2019 Customer Preference RFP action Item is as follows:

> PacifiCorp will work with customers to achieve their respective resource preference requirements. By the end of Q4 2019, sign a fifteen year 80 MW Power Purchase Agreement (PPA) for Utah solar for six Utah Schedule 34 customers. By the end of Q4 2019, sign two 20-year PPAs of approximately 80 MW for a large Utah Schedule 34 customer. Monitor the

[146] AR 603, Commission Order No. 17-232, June 29, 2017, p. 13.

[147] OAR 860-088-0060(2) allows up to 2.5 percent of the Company's 2016 system peak load, which is approximately 64 MW. Commission Order No. 19-392 provides direction for the utilities to credit participants for the 50 percent of that 64 MW.

finalization of rules by the Public Service Commission of Utah for HB 411 (anticipated by the end of Q1 2020), that provides a path forward for development of a program for participating communities to begin procuring renewable resources.

As these are Utah-specific programs to allow Utah entities to acquire power, these programs should not be allowed to negatively impact Oregon ratepayers. Staff would like PacifiCorp to provide a clear explanation of how the Company's implementation of these programs will avoid impacting Oregon ratepayers.

At the December 17, 2019, IRP presentation to the Commission, PacifiCorp mentioned that the customer preference sensitivities in the IRP may help indicate whether Utah customer preference resources are impacting the rest of the system. Staff interprets this to mean that if the base-case customer-preference sensitivity has higher costs than the zero-customer-preference portfolio, then the customer preference programs can be said to negatively impact non-participating customers. The sensitivities in the 2019 IRP show that the no-customer-preference sensitivity shows a benefit of $81 million, and the high-customer-preference sensitivity shows a benefit of $22 million relative to the preferred portfolio.[148] These results imply that there may be some impact to Oregon ratepayers from the expected Utah customer preference programs. Staff will be interested to look more closely at the assumptions, outputs, and implications for these sensitivities, especially around ownership.

10.5 TRANSMISSION PROJECTS IN THE ACTION PLAN

In its IRP Action Plan, PacifiCorp is asking for Acknowledgment of a variety of transmission projects, including Energy Gateway South, a 400-mile, 500-kilovolt (kV) transmission line from the Aeolus substation to the Clover substation to Mona, otherwise known as "Aeolus-to-Mona" or "Aeolus WY to Utah South." The Company also asks for acknowledgment of upgrades, such as Utah Valley reinforcements, Northern Utah Reinforcements, Utah South Reinforcements, and Yakima Washington reinforcements. The action plan also includes further Boardman to Hemingway analysis and completion of Gateway West Segment D.2. The total cost of all of the Action Items related to transmission lines and upgrades is over $2.4 billion.[149] Due to the limited information about the upgrades or their costs in the Action Plan, Staff is continuing to investigate the assumed costs and justification for these resources. Staff provides preliminary comments below.

Energy Gateway South

In addition to concerns with transmission modeling in the IRP discussed above, Staff is concerned about the inclusion of Energy Gateway South in the action plan. Because the cost-effectiveness of Gateway South is directly tied to PTCs, Staff is concerned that the benefits associated with production tax credits may never materialize if an all-source RFP selects a winning bid that does not include Wyoming wind. Due to this uncertainty, and because other transmission projects appear to be of superior value to

[148] PacifiCorp 2019 Integrated Resource Plan. Volume I. Pages 269-270

[149] Based on cost information in the 2019 IRP and PacifiCorp's response to Staff DR 96, included in Attachment A to these initial comments.

Oregon customers, Staff cannot in confidence recommend acknowledgment of Gateway South construction.

Projects Excluded from Preferred Portfolio

The Company is also requesting acknowledgment for action items involving transmission projects that are excluded from the preferred portfolio. For example, even though Section D.3 was not selected by the model as part of the preferred portfolio, PacifiCorp states in the Action Plan and the transmission chapter of the IRP that it plans to continue funding actions necessary for federal permits and supporting the development of this segment through public outreach. Even though B2H was not included in the preferred portfolio, PacifiCorp states that it plans to continue to support the project.

Staff seeks clarity on the reasons why the value that PacifiCorp apparently sees in Energy Gateway transmission segments has not been shown in IRP modeling. In a data request to PacifiCorp, Staff requested more information about why PacifiCorp believes these Energy Gateway transmission resources to represent value to ratepayers, even though that value could not be fully captured in the IRP models. PacifiCorp responded that the full value of the projects is not reflected in the current IRP modeling.[150] In Staff's view, PacifiCorp did not provide satisfactory reasons as to the apparent disconnect between the resources' value in the action plan and their seeming lack of cost-effectiveness in IRP portfolios.

Projects Already in Progress

Additionally, PacifiCorp has asked for acknowledgement of several transmission Action Items that are already complete, substantially complete, or will be substantially complete by the time the Oregon Commission issues an acknowledgement order. For example, construction of Segment D.2 of Energy Gateway, the Aeolus-to-Anticline 140-mile 500 kV transmission line, is already in progress and construction of the Vantage-Pomona Heights 230 kV line is already in progress. In Order No. 14-252, the Commission noted that energy utilities that desire acknowledgment of an investment decision should request acknowledgment before the required project is substantially completed. Yet, these projects are either complete or will be substantially complete by the time the Commission issues an acknowledgement order.

Staff cannot recommend acknowledgement of these action items as written. In general, the continuation of a project that should have been considered for acknowledgement in a previous IRP does not require an acknowledgement if no new information is presented. Staff finds the inclusion of new action items that are nothing more than business as usual to be confusing and unnecessary. Simple progress updates to past projects may be useful in the IRP for context, but do not belong in the Action Plan.

Lack of Specificity

PacifiCorp also requests acknowledgment for Action Items in which the Company does not provide total costs or additional detail on interconnection upgrades because they will ultimately depend on winning bids for its proposed all-source RFP.[151] In particular, these are the general "Utah Valley Reinforcements"

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[150] See PAC response to Staff DR 15, included in Attachment A to these initial comments.

[151] See PacifiCorp response to Staff Data Request 101, included in Attachment A to these initial comments.

in Action Item 3b, and the "Yakima Washington Reinforcements" in Action Item 3e.[152] Costs, location, and other project details related to these Action Items are unknown. Thus, the Company appears to be presenting a "just-in-case" acknowledgment request where costs, location, and specifics will not be determined until a later date. Staff does not believe "just-in-case" acknowledgements are appropriate to include in an Action Plan and also questions the appropriateness of including these types of interconnection upgrades in an IRP. For example, PacifiCorp confirms that one of its interconnection upgrades, at a cost of $5.4 million, has been identified as an upgrade for transmission service request (TSR) Q2469 Milford Solar.

Some of these investments appear to be facilitating interconnection for third parties, and including such projects for acknowledgment is relatively new to the IRP process. While Staff can appreciate the Company's desire to be transparent about the types of investments it expects to make within the next five years, inclusion in the Action Plan may not be appropriate and may be better addressed through the TSR/interconnection queue process and a subsequent rate case, if appropriate.

10.6 RPS ACTION ITEM

PacifiCorp's RPS action item says that the Company will pursue unbundled RFPs to meet state RPS compliance requirements and, as needed, issue RFPs for then-current-year unbundled RECs to qualify for the California and Washington RPS targets. Additionally, PacifiCorp says that it will "Maximize the sale of RECs that are not required to meet state RPS compliance targets."

In discovery, PacifiCorp clarified for Staff that it will not seek to acquire unbundled RECs for Oregon.[153]

Recommendations:

- **Staff would like more clarification on the meaning of maximizing the sale of RECs not required to meet RPS targets.**
- **Staff is also curious what portion of unnecessary RECs PacifiCorp plans to sell. Is PAC planning to sell all RECs instead of using its REC bank?**
- **PAC should update its RPS action item to specify the states' RPS for which it will perform these actions.**

[152] See PacifiCorp response to Staff Data Requests 101 and 103 included in Attachment A to these initial comments.
[153] See PacifiCorp response to Staff Data Request 62, included in Attachment A to these initial comments.

11. OTHER LONG-TERM PLANNING TOPICS

11.1 CLIMATE ADAPTATION

Climate change is likely to impact important aspects of PacifiCorp's operations over the IRP planning horizon.[154] As a utility providing essential services to customers, PacifiCorp should demonstrate that it is planning to adapt to expected changes in climate in its service territory.

Staff's initial assessment is that a robust climate adaptation plan should include reporting on "n-1" resilience modeling, as well as modeling the expected effects of a multiple-day cold snap or heat wave. It should include assessment of vegetation management, and the potential implications of cascading blackouts. Staff requests that the Company plan for climate adaption with stakeholder input and include a report as a part of its next IRP.

Recommendation:

- **PacifiCorp should provide a climate adaptation plan in its next IRP.**

11.2 CO2 EMISSIONS FORECAST

Climate legislation in Oregon may require PacifiCorp to develop an accurate forecast of CO2e emissions attributable to Oregon load.[155] Issues that Staff will be interested in looking further into will include whether the coal unit dispatch behind the forecast is realistic, whether the effects of SB 1547 on coal emissions attributable to Oregon have been taken into account, and whether the forecast availability of renewables from other markets such as California solar has been taken into account. While it is impossible to know exactly what a future Oregon climate bill may require in terms of CO2 forecasting, Staff would like to begin this conversation in the 2019 IRP in the hope that it can be continued at a later time to arrive at a truly accurate forecast if carbon legislation passes in Oregon.

Recommendation:

- **PacifiCorp should present the emissions forecast in its preferred portfolio for discussion by stakeholders**.

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[154] Oregon Global Warming Commission's 2018 Biennial Report to the Legislature, in particular Section 1, for a discussion of the state's current understanding of climate change impacts and ways in which they have evolved over time. https://www.keeporegoncool.org/s/2018-OGWCBiennial- Report.pdf.

[155] CO2e means Carbon Dioxide equivalent and includes gasses other than Carbon Dioxide.

11.3 GREEN FIRST MORTGAGE BONDS

First mortgage bonds are a common way of raising debt for utilities, and they are considered a secure, low cost way to raise funds. Investors may be willing to accept a lower return on bonds with verifiable green attributes, and as a result green bonds may be an especially low-cost way to raise capital. Green bonds could help PacifiCorp build new renewable resources at a discount, potentially providing substantial ratepayer savings and facilitating new renewable development in the future.

There have been many successful issuances of green bonds in recent years. In just one example, MidAmerican Energy recently issued $850 million in green bonds to help finance three wind repowering projects in 2019.[156, 157, 158, 159]

Staff would like to ask PacifiCorp if it has considered issuing tranches of green first mortgage bonds to attempt to lower costs of new renewable infrastructure.

Recommendation:

- **PacifiCorp should discuss in reply comments any potential barriers to implementing green bond tranches, as well as any potential benefits that may be associated with issuing green bonds for upcoming renewable infrastructure. PacifiCorp should also briefly describe how any low-cost financing for renewable resources could affect IRP portfolios.**

11.4 IRP STAKEHOLDER PROCESS MOVING FORWARD

On November 13, 2019, PacifiCorp filed a notice in LC 70 that it plans not to file a 2019 IRP Update, and instead will focus on the 2019 IRP and preparation for the 2021 IRP. Staff is concerned about PacifiCorp's decision to skip the update to the 2019 IRP and instead move right away into the 2021 IRP process.[160] PacifiCorp plans to file the next IRP in March 2021.
Staff is uncertain why the Company plans to file a new IRP less than one year after the acknowledgement decision is scheduled for the 2019 IRP. PacifiCorp indicates that it is seeking time to evaluate and implement new IRP modeling software. However, Staff fails to see how filing an entire IRP two months in advance of when an IRP update would be required gives PacifiCorp *more* time to evaluate new modeling software.

Staff is not necessarily opposed to the decision to skip the IRP update and instead file the next IRP on a consistent schedule as compared to previous IRPs. However, Staff notes that delaying the filing of the 2021 IRP until October 2021 could provide a more normative IRP lead-up process and give PacifiCorp,

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[156] https://www.midamericanenergy.com/green-bonds
[157] Anna Snyder. Chile's Inaugural Sovereign Green Bond Sets Strong Precedent for Future Issuances. Moody's. June 24, 2019.
[158] Gerrard Cowan. Investors Warm to 'Green Bonds.' Wall Street Journal. April 9, 2017.
[159] *Id.*
[160] LC 70. PacifiCorp's 2019 Integrated Resource Plan Update. https://edocs.puc.state.or.us/efdocs/HAH/lc70hah111238.pdf

Staff, and stakeholders more bandwidth to focus on the RFP that PacifiCorp plans to implement over the next several months.

12. CONCLUSION

Staff appreciates PacifiCorp's work and the extensive stakeholder engagement process that went into the development of the 2019 PacifiCorp IRP. Staff looks forward to reviewing PacifiCorp's reply comments in response to the questions and concerns raised in these initial comments. There are some concerns that Staff is hoping to address over coming months to work with PacifiCorp on improving the IRP so that Staff can recommend acknowledgement. Again, Staff's main concerns with the 2019 IRP come down to need versus opportunity, the lack of detail regarding RFP and transmission action items, the prioritization of certain transmission investments, and the lack of demand response in the near-term. Below is a list of the recommendations for PacifiCorp in these initial comments:

- **In the next IRP, PacifiCorp should perform sensitivities on two or three top-performing portfolios in order to compare performance in those futures.**

- **PacifiCorp should update the Preferred Portfolio with a forecast of new QF capacity that reflects historical trends.**

- **Staff recommends that the Company attempt to provide more transparency and information in future IRP filings while maintaining the Company's business interests.**

- **Staff recommends that the Company provide further insight into the metric used to determine an improvement in load forecast accuracy.**

- **Staff recommends that the Company attempt to identify and document the source of the data abnormality whenever utilizing indicator variables in a regression.**

- **In PacifiCorp's reply comments, Staff would like a detailed explanation of how future load from transportation electrification is captured in the Company's load forecast. What is PacifiCorp's expectation of high, medium, and low EV load growth across its multistate territory, and how are these scenarios reflected in the Company's analysis of PacifiCorp's resource need?**

- **Staff recommends PacifiCorp explain how its market penetration models are reflecting the potential for PG adoption over the 2019 IRP planning horizon.**

- **Staff recommends PacifiCorp should demonstrate whether policy drivers have been appropriately considered in the Navigant PG study. If they have not been appropriately considered, then PacifiCorp should re-assess a few top portfolios using the high Navigant private generation forecast, since a lack of policy driver assumptions in the Navigant study would bias the estimates downward.**

- **Staff recommends PacifiCorp explain how it's considering distributed storage technologies in the 2019 IRP.**

- **Staff requests that PAC re-run its preferred portfolio to reflect the PTC extension.**

- **Staff requests that PacifiCorp respond to Staff's comments on the PTC expiration by providing additional discussion of how PTC and ITC eligible resources are modeled in the 2019 IRP.**

- **Staff recommends that the Company model multiple supply side resource cost scenarios to better reflect technology, policy, and market uncertainty in future IRPs.**

- **PacifiCorp should update the preferred portfolio by allowing wind plus storage at the Dave Johnston site.**
- **PacifiCorp should report back to the Commission on the feasibility of contacting customers to gauge interest in a distributed standby generation agreement.**

- **Should customer interest exist, PacifiCorp should report back to the Commission on the viability of implementing a Distributed Standby Generation program.**

- **Staff requests that, if batteries are still a prominent resource considered in the next IRP, PacifiCorp should include in its next IRP a study of potential battery storage remediation, recycling, and disposal methods and costs.**

- **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.**

- **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.**

- **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.**

- **Explain why other states are not experiencing similar levels of Class 2 DSM growth as Oregon is in LC 70.**

- **Provide state-by-state data of the state winter and summer peak (MW) relative to Class 2 DSM MW contribution for 2020 through 2030, so as to understand how Oregon is contributing to local and system peaks.**

- **PacifiCorp should continue to study alternative bundling approaches for application in future IRPs.**

- **PacifiCorp should report back to the Commission on what learnings from its ongoing work to improve energy efficiency selection with Energy Trust and from the Oregon Energy Efficiency Forecasting Analysis Report should be applied to forecasting in other states to ensure the appropriate level of energy efficiency is properly selected.**

- **PacifiCorp should work with Staff to understand the data collected by AMI in PacifiCorp's Oregon service territory and to determine the appropriateness of utilizing AMI to develop EV TOU rates, CPP, and ways to leverage the deployment of Class 3 DSM to strengthen the effects of demand response offerings.**

- **Before the next IRP, PacifiCorp should hold a workshop with parties to discuss the development of potential Class 3 DSM pilot offerings, especially for electric vehicle owners, and to explore how the resource planning process can be improved to either better reflect Class 3 DSM as a load reduction or select it as a supply resource.**

- **PacifiCorp should introduce a TOU/CPP/DPP rate in Oregon for all rate classes within one year, or in the next general rate case, whichever occurs first. Work with Staff through a workshop and a filing in LC 70 for development of a proposed TOU rate.**

- **In reply comments, the Company should address reliability benefits of Gateway South and the role of Gateway South in Utah reinforcement.**

- **In reply comments, Staff requests PacifiCorp discuss why only one in-service date was considered for Segments E and H, and whether further analysis could provide more insight into the optimal timing for these segments.**

- **Staff would also like PacifiCorp to discuss in its reply comments which factors are making the economics of Energy Gateway South so favorable that it is chosen in each IRP portfolio. Are there specific low-cost resources enabled by Gateway South that could not be connected to B2H or other Energy Gateway segments? If so, is there a reason that similar resources could not cost-effectively be connected to B2H or other Energy Gateway segments instead?**

- **Staff requests PacifiCorp provide a charting of projected line utilization in both directions for Case P-26 (with EGS and B2H), for P-45CNW (preferred portfolio), and for P-45CP (preferred portfolio plus Dave Johnston wind in 2027). Information requested includes a depiction of actual current flows, and how those flows are projected to change in each direction with each additional segment of Energy Gateway on an hourly basis, across a calendar year, and in aggregate by summing line flows in both directions.**

- **PacifiCorp should report on the possibility of completing B2H in 2024 to pair with PTC wind near to the Western BAA.**

- **Staff would like PacifiCorp's reply comments to address regional needs for western transmission projects, and explain why PacifiCorp's analysis in the SO model does not show net benefits to PacifiCorp customers from B2H, even though the NTTG transmission studies indicate that it will be an important part of resolving transmission issues in Oregon by 2026.**

- **Staff also requests PacifiCorp discuss the likelihood that the entire Energy Gateway project could be required by FERC interconnection or transmission service rules in the near term. If this is likely to be the case, then the question of whether PacifiCorp Oregon customers should plan for these resources should be discussed, beginning in this IRP cycle.**

- **Staff would like PacifiCorp to provide more explanation in reply comments as to how and why the Energy Gateway transmission projects' regional value, as shown in recent NTTG studies, has not been captured in IRP modeling. If the projects are needed for reliability in the region, but are not part of a least cost, least risk portfolio for PacifiCorp customers, then that may be an important conversation for PacifiCorp and the Commission to have in the near term.**

- **Staff would like PacifiCorp to provide a comparison of the cost, location, and capacity of generation resources selected in the action plan timeframe of the full EGS buildout case (P-25) as compared to the preferred portfolio.**

- **The Company should explain whether it would support the addition of a RFP scoring metric for a bidding resource's performance in the most probable EG buildout future.**

- **Staff requests an explanation of how new resources are assumed to connect to the future Energy Gateway transmission lines (segments D.1, D.3, E, F, and H), what new resources are able to utilize the new capacity on these lines, and whether wheels are assumed to be required.**

- **The Company should address the particulars of this newly-issued FERC Order in Docket ER19-2760-000 and clarify if and how transmission segments seeking acknowledgement within an Action Plan now would still be the best (i.e., least cost and risk.) The Company should also discuss maximum benefits as compared to alternative proposals that could come from entities like LS Power and affiliates, National Grid, or Next Era. PacifiCorp may also wish to discuss how the Company's planning, construction, and operations would control costs and better explain the relative risks of a PacifiCorp built and operated line vs. an independently built and operated alternative but similar transmission solution.**

- **Staff would like PacifiCorp to address in its reply comments whether the lack of any new additions in the west is a safe and reliable outcome, given the recent forecasts of regional WECC capacity deficit if no new resources are built in the region.**

- **Additionally, given the several hundred MW of QF projects currently scattered around various load pockets in Oregon and unable to interconnect, Staff would like PacifiCorp to explain what transmission investments and queue management reforms underlie the assumption that 895**

MW of solar with 124 MW of battery can be built and online in Oregon and Washington by 2024 without also addressing existing transmission and interconnection bottlenecks.

- **Staff would like PacifiCorp to describe in the Company's reply comments how the benefits of the Western Interconnection Synchrophasor Project are expected to continue with Peak Reliability's successor.**

- **Staff would like the Company to explain in its reply comments what benefits PacifiCorp expects to gain from AMI throughout its multistate system.**

- **PacifiCorp should submit an updated action item with an approximate quantity and type (energy or capacity) of the resource(s) that it will seek to acquire.**

- **Staff requests PacifiCorp explain in reply comments whether it plans for queue reform to influence its next planned RFP or if queue reform would only apply to future RFPs. Staff also requests a discussion of how PacifiCorp's queue reform might change the RFP process.**
- **Staff requests a workshop for PacifiCorp to share the details of its queue reform proposal with Staff and stakeholders.**

- **PacifiCorp should explain why the RFP design, scoring, and modeling was not identified in the IRP, whether these elements are anticipated to be used in the RFP, and confirm whether it is planning on a separate filing that allows for a thorough review by interested stakeholders in the IRP or IE selection docket prior to filing a draft RFP that will allow for the same review as in the IRP.**

- **Staff requests that in reply comments PacifiCorp provide an explanation of how these wheeling costs will be modeled in the next RFP.**

- **Staff requests PacifiCorp consider in its reply comments whether adding a geographic diversity scoring metric to the RFP could help improve the value of new resources to PacifiCorp's system.**

- **PacifiCorp should make its best estimate of when Cholla will actually retire, and use that date in any upcoming RFP analysis. Additionally, if the Company has new information about any unit, it should use that updated retirement date in the RFP.**

- **For coal retirements modeled as cost effective in a given year, PacifiCorp should actively pursue the actions in its action plan toward achieving the cost-effective retirement date. Otherwise the company risks eroding the customer benefits associated with the retirement dates found to be cost effective through the IRP analysis.**

- **Staff requests that PAC explain in reply comments its strategy to provide customer preference options in Oregon, and whether it plans to file a VRET in Oregon.**

- Staff requests that PAC explain how the Oregon CSP is accounted for in its IRP modeling and how it has complied with Commission direction to forecast the impact of CSP on its load-resource balances.

- Staff would like more clarification on the meaning of maximizing the sale of RECs not required to meet RPS targets.

- Staff is also curious what portion of unnecessary RECs PacifiCorp plans to sell. Is PAC planning to sell all RECs instead of using its REC bank?

- PAC should update its RPS action item to specify the states' RPS for which it will perform these actions.

- PacifiCorp should provide a climate adaptation plan in its next IRP.

- PacifiCorp should present the emissions forecast in its preferred portfolio for discussion by stakeholders.

- PacifiCorp should discuss in reply comments any potential barriers to implementing green bond tranches, as well as any potential benefits that may be associated with issuing green bonds for upcoming renewable infrastructure. PacifiCorp should also briefly describe how any low-cost financing for renewable resources could affect IRP portfolios.

This concludes Staff's Opening Comments.

Dated at Salem, Oregon, this 10th day of January, 2020.

[illegible] for Rose Anderson

Rose Anderson
Senior Economist
Energy Resources and Planning Division

OPUC Data Request 15

Transmission - See Figure 8.30 comparing a portfolio that includes B2H to one without B2H.

(a) Is PacifiCorp's justification for continuing to consider B2H as a resource that a B2H portfolio could show net benefits over a longer time horizon than the IRP 20-year timeframe? If not, what factors contribute to PacifiCorp's decision to continue to consider B2H and participate in the project, and why aren't they captured in IRP modeling?

(b) Does PacifiCorp consider net benefits a requirement of investing in a transmission resource? Please explain PacifiCorp's analysis.

Response to OPUC Data Request 15

(a) No. The factors that drive the continued participation in the permitting phase of the project may not be easily quantified and go beyond the Integrated Resource Plan (IRP) sensitivity case used to develop Figure 8.30. Please refer to page 244 of PacifiCorp's 2019 IRP, Volume I which states "the company remains confident that additional Energy Gateway segments will provide incremental regional and customer benefits with an ongoing transition to the regional resource mix and as new markets develop".

Please also refer to PacifiCorp's 2019 IRP, Volume I, page 245 which states that potential incremental benefits that can be further explored in future IRPs and IRP Updates to the Boardman-to-Hemmingway Energy Gateway segment include:

- Connecting geographical diversity to help balance the intermittency of resources like wind and solar, to help meet clean-energy standards and bolster resource adequacy.

- Decreasing market reliance by providing incremental infrastructure that can connect additional resource to load.

- Improving reliability by increasing ability to share operating reserves among utilities and providing additional source for energy to flow.

- Helping to alleviate transmission congestion.

- Improving access to participate in the Energy Imbalance Market and generating customer benefits.

(b) PacifiCorp considers net benefits when evaluating transmission investments and assuming all regulatory requirements, contractual constraints, costs, benefits, etc. have been considered. However, not all factors can be directly modeled, as indicated above, and out-of-model adjustments or considerations may be required. Additionally, certain transmission investments may be necessary to comply with Open Access Transmission Tariff obligations or reliability requirements.

OPUC Data Request 37

Load Forecast - For all for load forecasts generated by econometric modeling, please provide the following. Please use Excel spreadsheet format when significant amounts of data are provided:

(a) all datasets with all variables and data required to replicate all econometric results; Please include headers for each column and a key explaining the units of each variable and any other pertinent information about the variable.

(b) A list of any and all econometric equations used in the load forecast and which forecast each equation was used for;

(c) a brief description of all included variables, including but not limited to the variable name, and source;

(d) all supporting justification for the inclusion of each variable;

(e) The name of each software used in the load forecast and which portion of the load forecast it was used for;

(f) All code used to generate the load forecast in the language used by the Company to generate the forecast;

(g) all regression outputs, including coefficients, standard errors, and other common statistical outputs;

(h) A detailed explanation of all specification and other model testing employed that was sufficient to the Company to justify the model's validity.

Response to OPUC Data Request 37

(a) Please refer to the confidential data disk accompanying PacifiCorp's 2019 Integrated Resource Plan (IRP), specifically the state folders provided in folder "Chapters + Appendices_CONF/ Appendix A - Load Forecast Details_CONF/ Load Forecast Models CONF" for spreadsheets containing each model for each jurisdiction. The "Data" tab in each spreadsheet contains data for each variable used in each model. Note: to protect individual customer data, the independent variable data from the "Data" tab, coefficients from the "Coefficients" tab and the "Predicted" tab for the following models have been redacted: Idaho Industrial, Oregon Commercial and Industrial, Utah Commercial and Industrial, Wyoming East and West Industrial. Please refer to Attachment OPUC 37 which provides details on the units of the variables. Please refer to column F of the "Coefficients" tab of each model for a description of the data in each independent variable.

(b) Please refer to the company's response to subpart (a) above. Specifically, please refer to the "Coefficients" tab of each model for the details of the econometric equation for each model.

(c) Please refer to the company's response to subpart (a) above. Specifically, please refer to column F of the "Coefficients" tab of each model for a description of the data in each independent variable. Also, please refer to Attachment OPUC 37 for the description of the dependent variables and the source of each variable.

(d) The company objects to the request as it is overly broad and unduly burdensome. Notwithstanding the foregoing objection, the company responds as follows:

The PacifiCorp electric service territory is comprised of six states and within these states the company serves customers in a total of 88 counties. The level of retail sales for each state and county is correlated with economic conditions and population statistics in each state. The company uses economic data (such as employment and population data), weather and monthly variables to forecast its retail sales.

The company forecasts the number of customers using IHS Markit's forecast of population and households as the demographic drivers. For the commercial class, the company forecasts sales uses non-manufacturing employment and total employment in addition to weather-related variables. The majority of industrial customers are modeled using manufacturing employment as the economic driver. An industrial production index is used as the economic driver for Utah. Weather variables are incorporated into the company's modeling to capture the weather response of load, while monthly variables are used to capture seasonality.

(e) All econometric modeling was performed using Metrix ND 4.7 licensed from ITRON.

(f) The company objects to the request as all modeling is performed internal to the Metrix ND software, the source code is proprietary to ITRON.

(g) Please refer to the company's response to subpart (a) above. Specifically, please refer to the "Coefficients" tab of each model spreadsheet for coefficients, standard errors, T-Statistic and P-Value of each included variable in the model. Please refer to the "Model Statistics" tab of each model spreadsheet for other common statistical outputs.

(h) The company objects to the request as it is overly broad and unduly burdensome. Notwithstanding the foregoing objection, the company responds as follows:

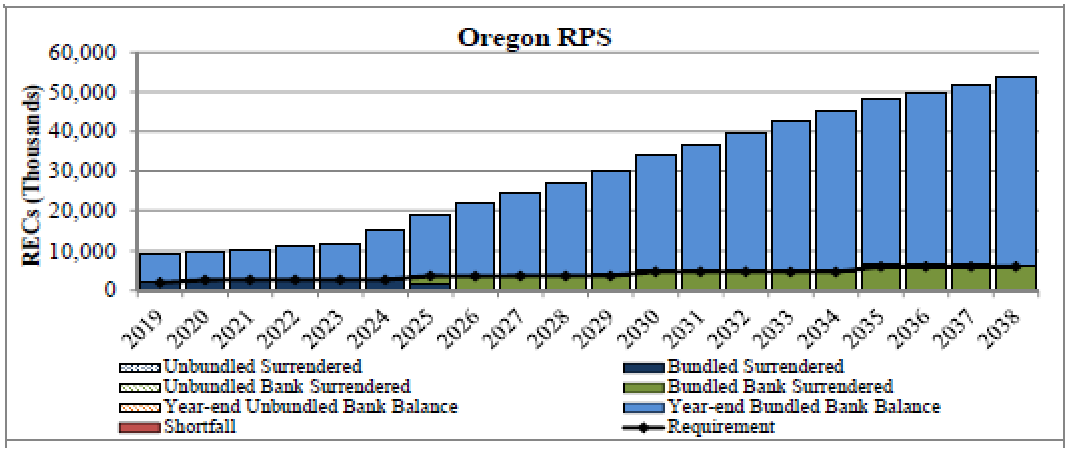
As part of developing a forecast, the company evaluates the final model to ensure that it meets goodness of fit tests (T Statistic and P-Value of individual Coefficients, Adjusted R-Squared, F Statistic and Durbin-Watson Statistic). Furthermore, the company evaluates the stationarity of final model to ensure that the residuals of the final model are free of significant autocorrelation as measured by the Auto Correlation Function (ACF), Partial Auto Correlation Function (PACF), Durbin Watson Statistic and sum of the coefficients of Autoregressive terms.

OPUC Data Request 62

Action Plan - Please explain action item 6 in more detail. Please include a response to the following with the Company's explanation:

(a) Please explain why PacifiCorp plans to pursue unbundled RECs when Figure 1.13 shows the Company has an abundance of generated RECs in Oregon.

(b) Please indicate whether PacifiCorp plans to utilize any unbundled RECs for compliance with the Oregon RPS.



(c) Please state whether the Company plan to sell any RECs that are not immediately needed for RPS compliance.

(d) Please confirm whether or not the Company will maintain a sizable REC bank if it does not sell any RECs in the near future.

(e) Please provide any available information related to PacifiCorp's plans regarding the RECs that it plans to bank or to sell.

Response to OPUC Data Request 62

(a) At this time, PacifiCorp does not intend to pursue any new unbundled renewable energy credit (REC) purchases for its Oregon customers to meet existing renewable portfolio standards (RPS) requirements due to its sufficient bank. However, PacifiCorp will continue to monitor its strategy relative to any developing renewable or emissions compliance requirements. PacifiCorp's 2019 Integrated Resource Plan (IRP) action item 6 states the company will pursue unbundled [REC] request for proposals (RFP) to meet its state RPS compliance requirements. It goes on to specify that these RFPs will be targeted for Pacific Power customers in states with a compliance need:

"[…] as, needed, issue RFPs seeking then current-year vintage unbundled RECs that will qualify in meeting California RPS targets through 2020. As needed, issue RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting Washington RPS targets".

(b) PacifiCorp intends to use current vintage and banked unbundled RECs that have been procured in agreements executed in prior years, as is cost effective, up to its 20 percent maximum allowance per Oregon Revised Statutes (ORS) 469A.145(1), and without limitation with respect to RECs associated with electricity generated in Oregon by a qualifying facility per ORS 469A.145(3).

(c) At this time, PacifiCorp does not plan to sell any RECs that are not immediately needed for RPS compliance. However, PacifiCorp will continue to monitor its strategy relative to compliance requirements and market conditions.

(d) Yes, the company will maintain a sizable REC bank if it does not sell any RECs in the near future. Maintaining a REC bank provides the company with flexibility to respond to changing requirements and market conditions.

(e) PacifiCorp intends to bank Oregon-allocated RECs, in excess of its compliance requirements, consistent with its reported bank in Attachment A of its Renewable Portfolio Standards Implementation Plan (RPIP). PacifiCorp filed its 2017 RPIP (2019 through 2023) on December 28, 2017 in docket UM 1914, and will file its 2019 RPIP by January 1, 2020. PacifiCorp will use RECs with the shortest life first for compliance, before using RECs with longer or unlimited lives. At this time, PacifiCorp does not plan to sell RECs that are allocated to its Oregon customers for RPS compliance purposes. However, PacifiCorp will continue to monitor its strategy relative to compliance requirements and market conditions.

OPUC Data Request 77

Transmission, Battery Storage, Action Plan - Has PacifiCorp performed an analysis investigating Oregon's ability to import renewables from Wyoming without B2H being in-service? If so, please provide each such study. If no such analysis exists, please provide a detailed explanation of why such a study was not performed.

Response to OPUC Data Request 77

The requested study is beyond the scope of integrated resource planning and would not be performed as part of the integrated resource plan (IRP) process. PacifiCorp develops its resource plan as a single system, which is consistent with system operations. Consequently, as part of its planning process, PacifiCorp does not evaluate how energy from specific resources are flowing across the transmission topology to meet load in specific jurisdictions.

From a transmission perspective, the existing transmission system and transmission service contracts provide the ability to import up to 1,600 megawatts (MW) from Wyoming to Oregon. Additionally, PacifiCorp, through its membership in Northern Tier Transmission Group (NTTG) for Federal Energy Regulatory Commission (FERC) Order 1000 regional planning compliance, has participated in transmission planning studies evaluating impacts of a High Wyoming Wind scenario, with and without Boardman to Hemingway (B2H). These studies evaluate the impacts of the Wyoming renewables on the greater transmission system and the ability of the combined resource portfolio and transmission system to reliably serve the load requirements of each member.

The NTTG Regional Transmission Plan for 2018-2019 evaluated impacts of the High Wyoming Wind scenario without B2H in seven unique scenarios representing various other transmission builds and the null case of no additional transmission to evaluate the system benefits and reliability impacts of each scenario using both power flow and production cost model analysis. The latest version of the NTTG Regional Transmission Plan as of December 19, 2019 is publicly available and can be accessed by utilizing the following website link:

https://nttg.biz/site/index.php?option=com_docman&view=download&alias=3288-nttg-2018-2019-regional-transmission-plan-for-steering-approval-12-19-2019&category_slug=steering-committee-meeting-material-12-19-2019&Itemid=31

OPUC Data Request 80

Transmission, Battery Storage, Action Plan - What economic benefits do PacifiCorp's Oregon customers stand to gain if the Company energizes Gateway South before B2H?

Response to OPUC Data Request 80

Oregon, and all other state jurisdictions, will benefit from Energy Gateway South, and the accompanying new wind generation, by realizing lower present value system costs, inclusive of production tax credit benefits, relative to a scenario where Energy Gateway South and new wind is not added to the system at year-end 2023.

OPUC Data Request 81

Transmission, Battery Storage, Action Plan - What reliability or energy benefits do PacifiCorp’s Oregon customers stand to gain if the Company energizes Gateway South before B2H?

Response to OPUC Data Request 81

Please refer to the company’s response to OPUC Data Request 80. New wind resources that accompany the Energy Gateway South project will provide energy and capacity benefits (i.e., reduced net power costs and production tax credit benefits) that outweigh the total cost of the transmission line and new wind resources relative to a scenario that does not include Energy Gateway South and accompanying wind capable of providing system energy and capacity.

Transmission reliability benefits to Oregon customers would be seen by building Energy Gateway South as presented in the 2019 Integrated Resource Plan, Volume I, Chapter 4 (Transmission), page 75.

OPUC Data Request 87

Transmission, Battery Storage, Action Plan - For each of the segments in Energy Gateway, including B2H, did the Company include wheeling revenues in the benefit-cost analysis when it considered new transmission buildout of any individual or any aggregation(s) of individual Energy Gateway segments? If so, please explain why such revenues were included. If not, please explain why such revenues were not included. If any such revenues were included, please provide any electronic spreadsheets or other documentation demonstrating when and for which Energy Gateway segments the Company chose to include wheeling revenues as either a benefit or an input to benefits.

Response to OPUC Data Request 87

The company did not include any third party wheeling revenues for the Energy Gateway segments, including Boardman to Hemingway (B2H), in the 2019 Integrated Resource Plan cost/benefit analysis. The company assumes the incremental transmission (PacifiCorp's share in the case of B2H) is fully available for serving PacifiCorp's retail load and does not assume third party wheeling revenues until there is reasonable certainty that a third party has committed to utilizing the transmission service.

OPUC Data Request 88

Transmission, Battery Storage, Action Plan - Please see page 74 of the IRP. The Company states that the Aeolus-to-Mona transmission segment "will allow PacifiCorp to implement system improvements…and enables the addition of incremental Wyoming wind resources to support customer needs and deliver value for customers in the most cost-effective way."

(a) Please provide a detailed description of what PacifiCorp is referring to by these "system improvements."

(b) What "customers" or customer groups will these "incremental Wyoming wind resources" be transmitted to, and over which specific transmission facilities will this generation be delivered to these customers or customer groups?

(c) Is it the Company's opinion that "incremental Wyoming wind resources" can be transmitted to PacifiCorp's Oregon customers without the addition of Segment H of Energy Gateway (B2H)? If so, please explain.

(d) The Company states that the "Timing of construction is driven by the phase-out schedule of federal production tax credits." In this sentence, is "construction" referring to the Aeolus-to-Mona transmission facility, to Wyoming wind resources, or to both? Please confirm whether the Company intended to say that construction of Aeolus-to-Mona is driven by PTC benefits.

(e) Does the Bureau of Land Management (BLM) allow utilities to apply for an extension of non-use permits? If so, for approximately how long (additional years) are such extensions, and what is the process by which to apply for an extension?

Response to OPUC Data Request 88

(a) PacifiCorp's announcement relative to advancing the Energy Gateway project segments into the transmission master plan has prompted a significant increase in large generation interconnection (LGI) requests, which PacifiCorp has evaluated based on LGI queue order and produced associated study reports summarizing system improvements necessary to integrate the proposed generation resource. While specific transmission facility additions or modifications associated with each LGI queue request have been defined, it is not possible to know the specific transmission improvements that may be necessary for specific projects until the PacifiCorp all-source resource request for proposals process included in the 2019 Integrated Resource Plan action plan has been completed.

(b) The “customers” that the “incremental Wyoming wind resources” will be transmitted to are existing PacifiCorp customers within PacifiCorp’s six state service territory. The transmission system used to move the resources to serve load include all existing and proposed new assets.

(c) Please refer to the company’s response to subpart (b) above.

(d) The Aeolus-to-Mona transmission line and accompanying wind generation are added as an element of a broader resource portfolio to meet customer needs over time. The transmission line is needed to enable interconnection of the incremental new wind resources—the new wind cannot be added without the transmission, similar to other resources in the preferred portfolio that trigger incremental transmission upgrades. Accounting for regulatory processes, procurement, and construction timelines, the Aeolus-to-Mona transmission line (Energy Gateway South) cannot be added before the end of 2023. Proceeding with the Energy Gateway South line and accompanying wind in 2023 is a lower cost solution because the new wind can qualifying for production tax credits.

(e) Yes, the United States Bureau of Land Management typically issues rights of way (ROW) grant renewals for terms of 30 years to 50 years. Application for renewal is made one year to two years prior to the expiration of the current ROW grant.

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).

OPUC Data Request 96

Transmission, Battery Storage, Action Plan - Please see pages 86 – 91 of the 2019 IRP. “Transmission System Improvements since the 2017 IRP.”

(a) Please provide the total cost of each project identified.

(b) Were any of these improvements acknowledged by the Oregon Commission in the 2017 IRP? If yes, which one(s)?

Response to OPUC Data Request 96

(a) Please refer to Attachment OPUC 96.

(b) The transmission improvements listed in the 2019 IRP were not listed on the 2017 IRP action plan and as such, were not acknowledged by the Public Utility Commission of Oregon.

Area	Project Name	Planned PPIS ($ million)
PacifiCorp East (PACE) Control Area		
1- Central WY	TPL 2017 Backup Bus Diff Rly-Jim Bridger	$0.4
2- Goshen ID	Goshen – Jefferson – Big Grassy 161kV Transmission Line	$8.5
2- Goshen ID	Goshen Area Load Tripping RAS	$1.3
2- Goshen ID	Goshen Spare 345-161 kV Transformer	$3.4
2- Goshen ID	Rigby and Sugarmill Shunt Capacitor Banks	$4.1
3- SE Idaho ID	Treasureton 138 kV - Bus Tie Breaker TPL	$1.5
4- Ogden UT	Ben Lomon-Syracuse-Parrish 138 kV 3 Term Line	$3.4
4- Ogden UT	Syracuse-Install 2nd 345-138 kV Trf TPL	$7.6
4- Ogden UT	Riverdale-El Monte RAS?	Project delayed. Planned ISD in 2023 for $1.7
5- Salt Lake Valley UT	TPL Brkrs 2017-MidVly CB130 CB131 CBL134	$0.5
6- Park City UT	Southwest WY Silver Creek Build 138kV Ln	$41.9
7- UT Valley UT	TPL 2017 Bup Bus Diff Rly-Camp Williams	$0.3
7- UT Valley UT	Spanish Fork Circuit Breaker Add TPL	$2.0
8- Southwest UT	Red Butte/Central-St George 4th138kv Cir	$2.1
9- East UT	Maeser and Vernal 3.6 Mvar cap bank	$1.8
PacifiCorp West (PACW) Control Area		
1- Yakima WA	Union Gap Add 230 - 115kV Capacity	$37.6
1- Yakima WA	Moxee Hopland 115 kV .67 Mile Ln Recond	$0.7
2- Portland OR	Troutdale Sub 230kV Swtchyd 115kV Rg Bus	$13.8
2- Portland OR	NE Portland Trans Upgrade	$20.6
3- Grants Pass OR	Grants Pass sub TRF replace	$10.9
4- Klamath Falls OR	Snow Goose 500-230kV Sub TPL002	$42.4
5- Yreka CA	Weed Sub Instl 115-69kV LTC Transfmr	$4.4

OPUC Data Request 101

Transmission, Battery Storage, Action Plan - Please see Action Item 3c. Northern Utah Reinforcements.

(a) Please specify which investments the Company is referring to when it states "As necessary to facilitate interconnection of customer-preference resources, PacifiCorp will proceed with system reinforcements in the Utah Valley."

(b) In bullet two, the Company is requesting acknowledgement of looping the existing Populus Terminal 345 kV line into both Bridger and Ben Lomond, building a 345 kV yard with 345/138 transformer and 138 kV yard buildout at Bridger plus ancillary 345 kV and 230 kV circuit breakers at Ben Lomond. Has the Company already started construction on any of these investments? Please provide the project timeline for these investments from beginning to energization. Please also indicate the total cost of this project.

(c) Please clarify what the Company means when it says, "Complete identified plan of service supporting 2019 IRP preferred portfolio for resource additions in northern Utah."

Response to OPUC Data Request 101

The company assumes that the reference to "Action Item 3c" is intended to be a reference to PacifiCorp's 2019 Integrated Resource Plan, action item 3b (Utah Valley Reinforcements). Based on the foregoing assumption and clarification, the company responds as follows:

(a) While no specific reinforcements have been identified, PacifiCorp acknowledges that improvements to the transmission system may be necessary, and will be dependent on type of resource, size and location. Each interconnection is different and specifics of the required investments are not known until all of the interconnection information is available.

(b) The company clarifies that the references to "Bridger" should correctly be to "Bridgerland," an existing substation located in northern Utah. Based on the foregoing clarification, the company responds as follows:

Construction of the referenced project has not commenced. The project is anticipated to start in 2021 with completion in November 2024 at a cost of $25.6 million.

(c) The plan of service refers to transmission improvements that may be identified either through the interconnection process or the transmission service request process in order to interconnect and designate the resource as a network resource. The resources will be determined through a future request for proposals process, therefore the exact transmission improvements are not yet known.

OPUC Data Request 103

Transmission, Battery Storage, Action Plan - Please see Action Item 3e. Yakima Washington Reinforcements.

(a) Please provide additional detail to the following Action Item: "To facilitate interconnection of preferred portfolio resources in the Yakima area, PacifiCorp will proceed with protection system and remedial action scheme upgrades to local 230 kV and 115 kV substations not otherwise included in network upgrade requirements for generator interconnection requests." Please also explain which generator interconnection requests this Action Item is related to.

(b) Has the Company already begun construction of the Vantage-Pomona Heights 230 kV line? Has the Company already received acknowledgement from the Oregon Commission on this project? Please provide the project timeline for this project. Please also indicate the total cost of this project.

Response to OPUC Data Request 103

(a) The set of potentially interconnecting resources is not known at the time of finalizing the 2019 Integrated Resource Plan (IRP) because the 2019 IRP preferred portfolio is based on proxy resources. Therefore, the purpose of this action plan item is to highlight that any protection system and remedial action scheme upgrades that would not otherwise be completed as part of individual interconnection requests in the Yakima area may be necessary to fully and reliably integrate the resources with the local area transmission system. PacifiCorp does not have any prior knowledge to indicate that such additional protection system and remedial actions scheme upgrades will be required, but included the action item to recognize the importance of maintaining system reliability with the changing resource mix identified in the preferred portfolio.

(b) Yes, construction has started with a current in-service date of May 2020 for $57.3 million. The project has been included in PacifiCorp's IRPs since 2015, but the company was not included in the company's action plan and therefore, the Commission has not provided acknowledgement. The current timeline for the project is as follows:

Milestone	Date
Project Authorization	January 2008
Engineering/Design Start	November 2016
Construction Bid awarded	September 2018
Final Federal Approval	October 2019
In-service	May 2020

REC Data Request 3

Please provide PacifiCorp's forecast of new qualifying facilities that it expects to enter into contracts with and be constructed over its planning period. Please provide the expected megawatts, average megawatts and technology type for such new qualifying facilities. If PacifiCorp has not performed such a forecast, please explain why.

Response to REC Data Request 3

The company's qualifying facilities (QF) assumptions were updated in the 2019 Integrated Resource Plan (IRP), including newly executed QF power purchase agreements (PPA). Please refer to PacifiCorp's 2019 IRP, specifically Volume I, Chapter 5 (Load and Resource Balance), pages 100 through 102. In addition, there is one new hydro QF included in IRP modeling that is not listed in Chapter 5:

New QFs
TSID Watson Micro Hydro, 200 kilowatts (kW)

Sierra Club Data Request 4.1

On March 29, 2019, the State of Utah passed the Community Renewable Energy Act (H.B. 411), which created an opportunity for Utah municipalities and counties to achieve a net-100% renewable energy portfolio by 2030. Communities choosing to participate in this new program must coordinate with PacifiCorp in order to "achiev[e] an amount equivalent to 100% of the annual electric energy supply for participating customers from a renewable energy resource by 2030."As of December 11, 2019, fourteen communities have adopted resolutions in conformance with the Community Renewable Energy Act: Park City, Salt Lake City, Moab, Summit County, Cottonwood Heights, Holladay, Salt Lake County, Oakley, Kearns, Kamas, Millcreek, Francis, Ogden, and Grand County.

(a) To what extent, if any, does the IRP reflect the potential for these communities to achieve a net-100% renewable energy portfolio by 2030? If it is PacifiCorp's contention that the current IRP is fully compatible with these commitments, please provide a demonstration of how renewable, and nonrenewable, resources might be allocated to meet this requirement.

(b) Please provide an estimate of the fraction of total Utah load represented by these 14 municipalities in 2018 and 2019.

(c) Please provide the annual 2018 and 2019 loads (in MWh) of each of the 14 municipalities represented above, individually, by customer type or tariff type.

Sierra Club will renew this request as additional communities opt in to the program.

Response to Sierra Club Data Request 4.1

(a) The 2019 Integrated Resource Plan (IRP) does not reflect any customer projects that would fall under House Bill (HB) 411. The 2019 IRP reflects communities' choice to achieve desired energy resource transition goals through the customer preference settings in the base model, specifically to reflect communities such as these in Utah. A higher customer preference sensitivity representing both Oregon and Utah communities with similar plans are reflected in case S-08. To give a range of results, case S-07 shows the impact on the 2019 IRP Preferred Portfolio with no customer preference. Both cases are provided on the confidential data disk accompanying PacifiCorp's 2019 IRP, specifically the System Optimizer (SO) model portfolio summaries in folder "System Optimizer Output\Sensitivity," and the Planning and Risk (PaR) model portfolio summaries in folder "Planning & Risk Output\Sensitivities."

    The company developed the customer preference forecast in October 2018, before the passing of the Utah legislation in March 2019. The December 11, 2019 list of Utah communities subscribed to the Community Renewable Energy Act (CREA) became available after the 2019 IRP was published (October 18, 2019); therefore what is reflected in the 2019 IRP does not reflect the full community list. While the requirement for customer preference is a changing target, there are more than sufficient renewables selected in the 2019 IRP Preferred Portfolio to cover all of these 14 communities' adopted resolutions. The determination of sufficiency is based on the Utah Energy Forecast of 28,748 gigawatt-hours (GWh) in 2030, applying the average of the communities' 2018 and 2019 retail loads as a percent of total state load (52.8 percent) to reach a customer preference need for these 14 communities of 15,173 GWh by 2030. 15,173 GWh is 19,441 GWh less than the new renewables added from 2019 to 2030 in the 2019 IRP Preferred Portfolio.

Please refer to PacifiCorp's 2019 IRP, specifically Volume II, Appendix M, page 395 for the customer preference loads chart.

(b) Please refer to Attachment Sierra Club 4.1.

(c) Please refer to Attachment Sierra Club 4.1.

PacifiCorp - Stakeholder Feedback Form

2019 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2019 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal 10/15/2018

*Name: Gloria Smith — Title: Managing Attorney

*E-mail: gloria.smith@sierraclub.org — Phone: (415) 977-5532

*Organization: Sierra Club

Address: 2101 Webster St., Suite 1300

City: Oakland — State: CA — Zip: 94612

Public Meeting Date comments address: Click here to enter date. ☒ Check here if not related to specific meeting

List additional organization attendees at cited meeting: Click here to enter text.

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Coal analysis methodology

☐ Check here if any of the following information being submitted is copyrighted or confidential.

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
Please see Exhibit A

PacifiCorp Response:

3. PacifiCorp should exercise reasonable discretion in its "stacked" retirement analysis.

PacifiCorp intends to use reasonable discretion in its stacked retirement analysis. PacifiCorp's proposed approach to analyze potential coal retirement dates is robust and will more accurately capture the economic benefits or costs associated with potential early closure relative to an endogenous retirement scenario. Under an endogenous retirement scenario, it is not possible to capture the economic impact of changes in system costs associated with an unknown retirement date. This includes changes in costs/timing for major overhauls, a ramp down in cost before the retirement date, changes to the costs for shared facilities at multi-unit plants, and changes to transmission rights and associated impacts on model topology. For these reasons, PacifiCorp does not plan to run an endogenous retirement scenario in the 2019 Integrated Resource Plan (IRP).

4. PacifiCorp's analysis should exclude non-essential coal unit investments from retirement cases.

PacifiCorp will consider this feedback and discuss results of its analysis at the December 3-4, 2018 public input meeting.

5. PacifiCorp's proposed intra-hour resource credit should be excluded from its coal analysis.

PacifiCorp provided further description of the Intra-hour Flexible Resource Credit calculation and values by resource type at the September and October 2018 public input meetings. PacifiCorp plans to calculate and present the impact on overall portfolio costs attributed to the Intra-hour Flexible Resource Credit as information only.

6. PacifiCorp's proposed battery storage and solar capital cost trajectories are unreasonably high.

PacifiCorp will discussed updates to it's model assumptions for battery storage and solar capital costs at the November 1, 2018 public input meeting. Those materials are available on the PacifiCorp's IRP website. As explained in that meeting, PacifiCorp's costs are consistent with market data.

7. PacifiCorp likely underestimates the capacity value of near- term renewable resources.

PacifiCorp believes 2030 is reasonable for its capacity contribution study but plans to evaluate reliability achieved by various portfolios and will consider differences in reliability.

8. PacifiCorp's proposed carbon price trajectories are unreasonably low.

As discussed at he the September and October 2018 public input meetings, PacifiCorp does not establish its CO_2 price forecast based on state-specific proposed climate policies. That being said, PacifiCorp plans to revise its assumption to start earlier (i.e. in 2025) for its base case.

9. PacifiCorp should provide additional information regarding its coal unit assumptions.

PacifiCorp will consider this feedback and discuss results of its analysis at the December 3-4, 2018 public input meeting.

Data Support: If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.
Click here to enter text.

Recommendations: Provide any additional recommendations if not included above - specificity is greatly appreciated.
Click here to enter text.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields

PacifiCorp - Stakeholder Feedback Form

2019 Integrated Resource Plan

PacifiCorp (the Company) requests that stakeholders provide feedback to the Company upon the conclusion of each public input meeting and/or stakeholder conference calls, as scheduled. PacifiCorp values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. PacifiCorp requests that stakeholders provide comments using this form, which will allow the Company to more easily review and summarize comments by topic and to readily identify specific recommendations, if any, being provided. Information collected will be used to better inform issues included in the 2019 IRP, including, but not limited to the process, assumptions, and analysis. In order to maintain open communication and provide the broader Stakeholder community with useful information, the Company will generally post all appropriate feedback on the IRP website unless you request otherwise, below.

Date of Submittal 7/11/2019

*Name: Rose Anderson Title: Utility Analyst
*E-mail: Rose.anderson@state.or.us Phone: 503.378.8718
*Organization: Oregon Public Utility Commission
Address: Click here to enter text.
City: Click here to enter text. State: Click here to enter text. Zip: Click here to enter text.
Public Meeting Date comments address: **6/21/2022** ☐ Check here if not related to specific meeting
List additional organization attendees at cited meeting: Click here to enter text.

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Modeling assumptions, B2H, transmission, EGS, Storage

☐ Check here if any of the following information being submitted is copyrighted or confidential.

☐ Check here if you do **not** want your Stakeholder feedback and accompanying materials posted to the IRP website.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.

1.
In the June 21 Public Input Meeting, PacifiCorp indicated the SO model may not always be able to select transmission endogenously, and identified an issue with endogenous transmission selection as the reason for cases like P-22 that select specific transmission in a specific year. Please elaborate on the circumstances when SO is not able to select transmission endogenously. Please briefly describe the reason for this issue.

PacifiCorp Response:

The System Optimizer model (SO model) can select endogenously from the transmission upgrade options made available to it. However, certain transmission segments may include benefits to other transmission segments, such as higher transfer capabilities on other paths, which cannot be incorporated into the model logic. Per the April and November 2018 public-input meeting materials and discussion, performance and topology limitations restrict the number and type of endogenous options that can be modeled. Endogenous transmission modeling has on average tripled SO model run times. Endogenous modeling can incorporate new or expanded transmission capacity between two transmission bubbles, but not between three or more bubbles. Incremental capacity that is "intra-bubble" also cannot be modeled. Some potential options have secondary impacts such as on Path-C constraints or may require three or more bubbles (this is the case with the Boardman-to-Hemingway (B2H) transmission project). Consequently, the B2H project cannot be adequately included as endogenous transmission options for model selection as the benefits and functionality of the line would be underrepresented. The net

* Required fields

benefits and/or costs of these options are therefore assessed in separate portfolios that force the segment in the model in order for them to be fully represented.

2.

In the B2H portfolios, P-25 and P-26, what year was B2H assumed to be in service? Please provide a brief description of why this year was chosen.

PacifiCorp Response:

B2H is assumed to be in-service in 2026 consistent with discussions with Idaho Power, the project sponsor.

3.

Was B2H ever allowed to be selected endogenously in any of PacifiCorp's IRP portfolios? If not, please explain PacifiCorp's reasoning for excluding it.

PacifiCorp Response:

No. B2H is a sponsor-driven project and the model is not capable of recognizing the benefits of B2H in isolation such that it would make sense to endogenously model the B2H as an option. Therefore PacifiCorp evaluated portfolios that specifically included B2H independently. Please see response to item #1 above.

4.

In the portfolios in which Energy Gateway South (EGS) is built in 2023, what year did PacifiCorp assume the associated Eastern Wyoming wind resource began construction and what PTC value did PacifiCorp assign to the wind project?

PacifiCorp Response:

The model assumes that concurrent with the Energy Gateway South transmission line being selected to come online in 2024 (a proxy for year-end 2023), that up to 1,920 megawatt (MW) of new wind interconnection at a 40% production tax credit could be selected.

5.

OPUC Staff has previously shown interest in an Oregon depreciation date study/portfolio. Does PacifiCorp plan to run a portfolio with Oregon depreciation dates?

PacifiCorp Response:

While not explicitly labeled as a depreciation study case, Case P-03 (the Regional Haze Intertemporal Case) includes coal retirement assumptions that are aligned with the depreciation study.

6.

Please provide a narrative explanation of how PacifiCorp models Wind + Storage and Solar + Storage projects in System Optimizer. Are there any requirements that would prevent renewables + storage from being located in a site with access to less transmission capacity than the sum of the capacity of the renewables and storage? For example, could a project with 200MW solar and 200MW battery be chosen for a location with access to only 200MW transmission?

PacifiCorp Response:

Per discussion and materials presented at the January 24, 2019 public-input meeting, storage options can cause nameplate capacity to exceed transmission capacity under the assumption that the company will not operate the battery so as to exceed transmission rights. Battery resource options are available for selection in the "parent" bubble within the new transmission topology that enables endogenous modeling of transmission upgrades. This allows these resource options to be chosen without other new resource alternatives that were otherwise required to charge the battery, and allows these resource options to be chosen without incremental transmission capacity. Note that the co-location of solar + storage also recognizes the cost savings associated with charging the battery

* Required fields

directly from the solar resource, and at the same time recognizes the restriction of the solar and battery components sharing a common interface to the grid.

7.
With Order No. 18-324, the Oregon Public Utility Commission adopted competitive bidding rules (CBRs) for electric companies, now set forth in Oregon Administrative Rules Division 860, Chapter 89, to replace the past use of Commission guidelines. Under OAR 860-089-0250(2), additional RFP information must be included in a utility IRP unless the Company intends to develop and seek approval of a different proposal.

OAR 860-089-0250 (2)

"The draft RFP must reflect any RFP elements, scoring methodology, and associated modeling described in the Commission-acknowledged IRP. The electric company's draft RFP must reference and adhere to the specific section of the IRP in which RFP design and scoring is described.

(a) Unless the electric company intends to use an RFP whose design, scoring methodology, and associated modeling process were included as part of the Commission-acknowledged IRP, the electric company must, prior to preparing a draft RFP, develop and file for approval in the electric company's IE selection docket, a proposal for scoring and any associated modeling."

Will PacifiCorp include RFP details in the IRP?

PacifiCorp Response:

PacifiCorp will comply with current rules, regulations and orders adopted by the Oregon Commission specific to the issuance of request for proposals (RFPs) for electric generation service in Oregon. As the 2019 Integrated Resource Plan is not yet final and the preferred portfolio and action plan not known at this time, PacifiCorp has not yet determined when or if a new RFP will be required or issued.

Data Support: If applicable, provide any documents, hyper-links, etc. in support of comments. (i.e. gas forecast is too high - this forecast from EIA is more appropriate). If electronic attachments are provided with your comments, please list those attachment names here.
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2019_IRP/PacifiCorp_2019_IRP_June_20-21_2019_PIM.pdf

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Recommendations: Provide any additional recommendations if not included above - specificity is greatly appreciated.

Please submit your completed Stakeholder Feedback Form via email to IRP@Pacificorp.com

Thank you for participating.

* Required fields