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

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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: **4/25/2022** ☐ 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.
Coal and reliability modeling

☐ 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.

See slide 5 of the April Public Input Meeting slides. OPUC has questions regarding the 1,425 MW cap on FOTs:
-What would be the cost implications of relaxing the 1,425 MW cap to a 1,435 MW cap (10 MW increase in cap). -What is the dollar amount of the change in revenue requirement from relaxing the cap by 10 MW?
-Does this dollar amount vary by area (division) and, if so, how and why?
-Staff believes the answers to these questions would help inform a discussion of the value of FOTs in the IRP. Would PacifiCorp consider providing the above analysis as a sensitivity to the preferred portfolio in the 2019 IRP?

PacifiCorp Response:

PacifiCorp has not conducted the specific study requested. However, PacifiCorp plans to evaluate the price risk associated with front office transactions (FOTs) by running a sensitivity that imputes a risk premium on the price of FOTs consistent with periods when non-normal market conditions can lead to price spikes in the market.

The impact of increasing the FOT limit would be to defer other demand-side and supply-side resources that are higher cost than the price assumed for an FOT, accounting for changes in system dispatch. PacifiCorp operates and plans as a single system and does not break out costs by division (*i.e.*, Pacific Power and Rocky Mountain Power).

* Required fields

A 10 megawatt (MW) increase in the limit would likely have a limited impact on system costs primarily because the incremental change in volume is very small relative to the overall size of PacifiCorp's system. PacifiCorp will consider developing an FOT sensitivity case, as time and resources permit, but would likely modify the incremental change to a larger figure.

In the meantime, PacifiCorp invites staff to review a limited FOT sensitivity case from the 2017 Integrated Resource Plan (IRP) (Case FOT-1). This case is summarized in Volume I of the 2017 IRP beginning on page 252. In this sensitivity, FOT limits were reduced by 400 MW (300 MW at Mona and 100 MW at NOB). Removal of these FOTs increased system costs by between $47 million and $286 million, with the range dependent upon environmental policy and natural gas price assumptions.

2.
See slide 40 of the April Public Input Meeting slides. Regarding the statement "Given aforementioned risk factors, 500 MW of capacity in excess…was required." Can PacifiCorp please provide an explanation of how the 500 MW was determined?

PacifiCorp Response:

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

3.
See slide 36 of the April Public Input Meeting slides. Regarding the statement on deterministic studies' assumption of "Average market prices without electric or natural gas price volatility and physical supply risks" and the 500 MW excess capacity requirement on slide 40, does this sentence mean that PAC is modeling physical supply risks, or not? If not, how does the 500 MW result change if there are NO assumed physical supply risks?

PacifiCorp Response:

PacifiCorp does not explicitly model physical supply risks for market purchases. Please see the response to question #2 above. The 500 MW incremental requirement is not explicitly linked to physical supply risk for market purchases. From a practical perspective, there is no scenario where physical supply risks are eliminated. Nonetheless, if physical supply risks for market purchases were theoretically eliminated, incremental capacity would still need to be held in reserve to mage a wide range of system risks.

4.
See slide 40 of the April Public Input Meeting slides. Regarding the statement "Allocated between East and West based on peak load by season," why allocate based on "peak load by season" and not on area shortfalls by season? Or, is this what Examples 1 and 2 imply, that the allocation is based on relative shortfall(s) by season?

PacifiCorp Response:

The referenced allocation is analogous to the determination of PacifiCorp's planning reserve margin, which is based on coincident peak loads in each load area. This is reasonable since the incremental requirement is intended to capture variability that is not present in the deterministic reliability study, but which is part of the stochastic studies used to determine the planning reserve margin.

While the 500 MW incremental requirement is allocated strictly based on peak load by season, the resources needed to meet this requirement do not necessarily need to be located in the same load area as the requirement, as transfers (i.e., sharing between the two areas) is allowed to the extent resources and transmission capability are available.

In addition, both East and West must meet all energy and reserve shortfalls, in addition to the allocated portion of the 500MW requirement. As a result, an area with a shortfall would face a requirement in excess of the amount based on its load alone. This is intended to mitigate the measured shortfalls and leave both areas with suitable degree of incremental capacity to account for variability that is not present in the deterministic reliability study.

5.

See slide 40 of the April 2019 Public Input Meeting, "Other resource types are locked at levels in pre-reliability portfolio." At these locked levels, are any existing thermal plants generating at less than capacity? In other words, do the locked levels include any "throttled-back" thermal plants? If so, by how much are such plants "throttled-back" in the aggregate? Why did PAC choose to lock only those resources and not others?

PacifiCorp Response:

By "locked", PacifiCorp is only referring to the portfolio selection, not resource dispatch. The process is as follows:

1. System Optimizer model (SO model) selects a portfolio including demand-side management, renewables, thermal, storage, etc.
2. That portfolio is evaluated in a planning and risk model deterministic study (with no special resource restrictions), and shortfalls/excess capacity available are measured for 2023, 2030, and 2038.
3. If there is a shortfall or excess capacity is less than the requirement, the resource selections the SO model made are held constant, except it can pick more energy efficiency, gas peakers, or energy storage to get up to the requirement. The SO model can also pick less of these in a given year, which allows it to move the selections forward in time.

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_April_25_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