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 8/7/2018

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Public Meeting Date comments address: **7/26/2018** ☐ 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.

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

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

All - WUTC staff intends to file feedback after each IRP meeting to keep the lines of communication open and to signal as soon as possible whether there are any concerns. Below are slide-by-slide comments and questions, working from the hard copy slides provided (120 slides total).

- Slide 7: Can you provide a brief overview of how costs arising from state policies on energy storage are assigned – per both the 2017 Protocol and the WCA?

PacifiCorp Response:

Assignment of costs is not part of the long term planning process, please refer to the West Control Area (WCA) or multistate protocol process (MSP) process for clarification.

- Slide 9: Definitely need more detail about RVOS model; unclear where the inputs come from, how location plays a role, etc. An example in context would be very helpful. Unless this is unintentionally a big ask, please provide the RVOS spreadsheet populated to evaluate a real or hypothetical project connected to Oregon HB 2193.

PacifiCorp Response:

The requested materials were provided via data disc.

- Slide 9: I'm not clear on the material / physical distinction between voltage support, frequency response and regulation.

PacifiCorp Response:

Voltage support is a localized issue while regulation and frequency response reflect balancing authority area (BAA) and interconnect wide conditions. Voltage support covers several categories of performance metrics. The most direct is maintaining adequate voltage at the end of long radial lines under heavy load or line outage conditions. Voltage support also involves dynamic issues such as balancing real and reactive power depending on the types of loads, resources, and system elements on a circuit. Regulation is the balancing of a single BAA's load and resources, referred to as Area Control Error (ACE), which is how much imbalance is flowing to or from neighboring BAAs. This is managed from minute to minute, but per North American Electric Reliability Corporation (NERC) reliability standard BAL-002-1, only requires compliance within 30 minutes. Frequency response reflects interconnect-wide load and resource balance. If a large generator trips offline, the frequency of the entire interconnect will drop from the 60 hertz (Hz) target, for example. Compliance with NERC standard BAL-003-1 requires each BAA to deploy resources within seconds to under a minute when a frequency drop occurs. A more detailed description of regulation and frequency response was provided in Appendix F in the 2017 Integrated Resource Plan (IRP).

- Slide 9: Outage mitigation is not a utility benefit – this seems thin. The utility is missing out on kWh of retail sales, at least. Perhaps narrative that explains how these benefits are negligible relative to the costs and benefits that are analyzed would make stakeholders more comfortable with PAC's decision to ignore any one benefit stream, no matter how small.

PacifiCorp Response:

To clarify, "utility benefits" are referring to reductions in cost of service for retail customers as a whole, not utility revenue. Assuming Pacific Power provides 99.98% service reliability, all avoided outages would only result in a 0.02% increase in retail sales and load. In the 2017 IRP Update, 2019 system load was approximately 10,000 megawatts (MW) at peak and 6,900 MWs on average. A 0.02% increase would be 2 MW at peak and 1.4 MW on average. While more load could result in fixed costs being spread to more customers, it would also result in higher variable costs, as optimization of PacifiCorp's resource dispatch means that each incremental megawatt should be at least equal in cost to the highest cost resource that has already been dispatched. The net impact is not expected to be a meaningful driver for retail customers as a whole, particularly in comparison to customer-specific requirements as discussed below.

While the benefits of outage mitigation on customer rates are small, there may be opportunities to allow customers to select either more or less reliable service. Customers seeking more reliable service could partner with PacifiCorp to locate storage resources at or near their location for outage mitigation. PacifiCorp would also deploy the resource to provide system benefits. The dispatch and cost-allocation would be inter-related, but could ensure other customers benefit or are at least indifferent to the arrangement. Similarly, customers that are willing to accept less reliable service could allow all or a portion of their load to be interrupted at short notice. PacifiCorp's Coolkeeper air-conditioning load control program is an example of an interruptible load. Several types of interruptible loads are included as resource options in the 2019 IRP.

- Slide 11: Very interesting slide; could be useful but needs more clarity. Appreciate the company's overarching point that there's diminishing value to the services a battery can provide.

PacifiCorp Response:

The highest value applications are limited in quantity. There are not hundreds of megawatts of distribution deferral opportunities for example, and thus applying a credit to all batteries for that use case would be unreasonable. The same is true for regulation and generation capacity, but the demand for both of these is impacted by the portfolio mix. Increasing variable energy resources (VERs) or early retirements could increase demand for regulation and generation capacity, respectively. Both of these requirements vary dynamically and are assessed in system optimizer (SO) and/or Planning and Risk Model (PaR). As a result, the key takeaway is not the specific values, but rather the need to consider assumptions about use cases and adjustments in light of the portfolio results, not just as a static input.

- Slide 13: some concern over modeling of batteries as input to IRP tools. How does the concept of degradation costs overlap with the concept of depreciation? Seems like, if degradation costs effectively replace a sliver of the battery with a 'new' sliver of battery, then the battery is evergreen, i.e., there will be a fully-depreciated battery ..? I feel like I'm missing something remedial here; apologies if so.

PacifiCorp Response:

Depreciation is an accounting treatment unrelated to how a resource is used, and while it will be aligned with expected operations over the long term, it doesn't drive those operational decisions. For the 2019 IRP PacifiCorp will attempt to emulate operational impacts where appropriate. The degradation cost for batteries could be compared to oil changes in a car, or overhauls at a gas plant. If oil changes in a car are required every 3,000 miles, then every mile can be considered to incur 1/3000th of the cost of the oil change. For gas plants, the metric is typically the number of starts and/or fired hours (i.e online hours). Each start or fired hour, depending on the maintenance contract, brings a unit closer to a required overhaul. As a result, operationally the unit should only be started if the expected margin covers the cost of the start. In both cases, no costs are actually incurred until the maintenance is triggered, but it is appropriate to consider the operational implications throughout, not only after the usage triggers a maintenance need. Degradation for Li-ion batteries can be considered on an analogous basis. Each time the battery is discharged, it is that much closer to incurring the cost of replacement of the storage equipment. Keep in mind "storage equipment" is only a portion of the installed cost of a Li-ion battery; inverters, interconnection, site, and balance of plant have longer lives.

- Slide 14: Would like more background on the valuation of benefits in this slide. What is being displaced for which use case?

PacifiCorp Response:

In addition to slide 14, please also refer to slide 17 from the July 26-27, 2018 public input meeting presentation, which shows the value of the various services when optimally stacked for Project #1. The displacement for the services is as follows:

Capacity or Resource Adequacy – During the sufficiency period, additional capacity from an energy storage resource displaces market purchases or Front Office Transactions (FOTs). The values shown reflect the incremental value of avoided market transactions as measured in the GRID model, relative to the market price paid. Because FOTs are block products covering many hours, they will result in purchases in some periods when PacifiCorp's needs are lower and they have economic resources. Due to limits on market sales, some of those economic resources may need to be backed down to accommodate the FOTs. The capacity cost of the FOTs reflects the margin between backed down resources and the market price. During the deficiency period, additional capacity from an energy storage resource was assumed to displace a Simple Cycle Combustion Turbine (SCCT) from the 2017 IRP Preferred Portfolio. The value is net of dispatch benefits (energy value) that the SCCT was expected to provide. For an IRP, both FOTs and proxy resources would vary dynamically as part of the portfolio optimization process.

Energy Arbitrage – In the Resource Value of Solar (RVOS) template, energy arbitrage reflects market purchases and sales to charge and discharge the energy storage resource. The volumes account for efficiency losses related to charging, as well as avoided line losses for batteries interconnected at lower voltages near load. Batteries connected near load avoid the line losses between the transmission system and their interconnection point while discharging. While they incur additional losses while charging, the net effect is a benefit due to arbitrage. Avoided line losses make the effective size of an energy storage resource larger, comparable to the difference between load at sales (metered without losses) and load at input (including losses).

Regulation – The regulation value includes two components. First, the cost of holding sufficient flexible capacity going into the hour. In Energy Imbalance Market (EIM), PacifiCorp must submit a balanced schedule resources to meet its forecasted load, as well as sufficient flexible resources. When energy storage resources are available, this can free up other flexible resources in PacifiCorp's portfolio to serve load and avoid hourly market purchases, or support additional hourly market sales. The specific marginal resources in PacifiCorp's portfolio that are designated to hold reserves varies by hour, and were calculated using the GRID model for the referenced analysis. For the IRP, the PaR model also captures the requirement to hold operating reserves. The second component of the regulation value is dispatch of an energy storage resource that is participating in EIM, against EIM prices. Within the hour, flexible resources are deployed in EIM and in each interval the EIM prices reflect cost of the marginal dispatchable resource, which varies as the net load and resource balance changes. The EIM prices reflect the cost of resources from across the EIM footprint.

Load Following – As with Regulation, Load Following allows other flexible resources in PacifiCorp's portfolio to serve load and avoid hourly market purchases, or support additional hourly market sales. The Load Following designation reflects dispatch of an energy storage resource that is not participating in EIM. Because the dispatch is not visible to or directed by EIM, the value is significantly less.

Spin/Non-spin Reserve – As with Regulation, Spin/Non-spin allows other flexible resources in PacifiCorp's portfolio to serve load and avoid hourly market purchases, or support additional hourly market sales, but does not provide any additional dispatch benefit as dispatches are infrequent and not based on EIM economics. Spinning reserve must be immediately and automatically responsive to frequency changes, whereas non-spinning reserve does not need to be immediate. Both need to be fully deployed within ten minutes.

* Required fields

Transmission Services Transmission Upgrade Deferral – This use case reflects the value of deferring transmission system capacity upgrades, i.e. avoiding the need to increase transfer capability.

Distribution Services Distribution Upgrade Deferral – This use case reflects the value of deferring distribution system capacity upgrades, i.e. avoiding the need to increase transfer capability.

• Slide 17: How was the value for EIM estimated? Also, how might the EIM valuation change if other big players like CA utilities install their own storage?

PacifiCorp Response:

The Intra-hour Flexible Resource Credit methodology is essentially the same as that underlying the EIM values shown on slide 17 from the July 26-27, 2018 public input meeting. Both reflect the expected benefits of an energy storage resource that is participating in EIM. The values on slide 17 reflect the specific characteristics of Pilot Project #1, rather than the characteristics of proxy resources in the 2019 IRP, and also reflect EIM data for the 12 months ending September 2017. The current analysis and results presented at the October 2018 public input meeting reflects data for the 12 months ending June 2018.

It is uncertain how EIM valuation might change in the future. Changes to the VERs and flexible resources in the EIM footprint can result from both existing EIM participants as well as new participants, and would also drive changes in Intra-hour Flexible Resource Credits. The addition of new participants can result in both greater variability, which could increase intra-hour flexible resource credit values, as well as a larger pool of flexible resources, which could decrease intra-hour flexible resource credit values. While sizeable additions of flexible energy storage resources could drive values down, they could also increase the value and adoption of VERs, which could drive credits back up. The magnitude and net effect of these drivers are difficult to ascertain, though as EIM participation increases, the effect of any one participant's resource changes on the EIM as a whole will decline.

• Slide 23: need more info about solar PPAs, and perhaps a primer on OR Schedule 272. Was this acquisition in the 2017 IRP? Was it acquired pursuant to a need, or prompted by a tariff? Or both?

PacifiCorp Response:

Please see link to schedule https://apps.puc.state.or.us/edockets/docket.asp?DocketID=20395 for more information. The 2017 IRP identified a resource need. The PPAs were pursued as system resource to provide energy and capacity benefits that are expected to be lower cost than other resource alternatives.

• Slide 25: If customers opt into a separate fleet of generation as through UT Schedule 34, does that have an impact on cost recovery for existing resources?

PacifiCorp Response:

Approval of contracts under Schedule 34 is on a case-by-case basis. Treatment of existing resources in setting rates under Schedule 34 is not strictly defined in Schedule 34 and may be differentiated between new customer load and existing customer load. Nonetheless, the contracts must be shown to be in the public interest and the tariff explicitly states the following: Evaluation of the public interest shall include consideration of use of system facilities and contributions to system fixed costs, and any other issues the Commission determines to be relevant.

• Slide 27: Questions about difference model vs auto-correlation corrections. I'm out of my depth. Agree with OPUC staff comment that double-checking IHS record on economic forecasting seems like a good idea.

PacifiCorp Response:

One of the assumptions for linear regression modeling is that residuals are mutually independent (no autocorrelation). Approaches for correcting for autocorrelation in linear regression models include the use of autoregressive terms and predicting the change in model input (differenced model). Before the 2019 IRP, PacifiCorp used autoregressive terms to correct for autocorrelation. PacifiCorp performed a historical comparison and determined the autoregressive model was under predicting customers. The differenced model produced a more accurate customer forecast. As such the differenced model was used to forecast customers for the 2019 IRP resulting in increased residential sales. The Company intends to evaluate the historical performance of the Information Handling Services (IHS) economic forecast.

* Required fields

• Slide 27: Where are these commercial and residential increases happening? Is the residential growth both in # of customers and in usage-per-customer? Is that across PAC's service territory?

PacifiCorp Response:

Relative to the 2017 IRP Update, the 2019 IRP commercial sales forecast increased in Utah, Oregon, Washington and California. The residential sales forecast increased in Utah, Idaho, Oregon, Washington and is relatively unchanged in California. Relative to the 2017 IRP Update, the projected residential customer counts for the 2019 IRP has increased in all states within PacifiCorp service territory, with exception to Wyoming over the 2019 to 2021 timeframe. Relative to the 2017 IRP Update, the use-per-residential customer for the 2019 IRP is generally expected to increase in all states, while use-per-customer is expected to decline in Wyoming.

• Slide 30: Might a marked increase in cryptominers have an impact on FOT availability? If cheap power at Mid-C ends up being purchased locally instead of sold wholesale, that could alter the market.

PacifiCorp Response:

PacifiCorp has not evaluated changes in load in the western interconnection due to cryptominers and its potential impact on wholesale market liquidity or prices.

• Slide 32: Is this graph inclusive of DSM?

PacifiCorp Response:

Use per Residential Customer (UPC) illustrated in slide 32 is post-demand-side management (DSM) and was derived using DSM from the 2017 IRP Update.

• Slide 39: What is the frequency of updating a DSP study? Is this an iterative process?

PacifiCorp Response:

Distribution Planning studies are refreshed on a three, four, or five-year basis. This cycle is set based on the change within a planning study area. PacifiCorp currently has 13 distribution planning study areas in Washington. The planning studies are done on a five-year planning horizon, and the study process is iterative.

• Slide 41: What is PAC doing to increase their capacity to perform this analysis more frequently? I heard in the meeting that they're developing tools to make this much faster than every two years. Would like to see that.

PacifiCorp Response:

Improvements in planning tools enhance analytical capability and benefit accuracy of the planning studies. They do not impact the frequency or need to conduct studies more frequently.

• Slide 44: Non-wires screening tool is pretty cool. Request a recent example for WCA (preferably WA) project.

PacifiCorp Response:

Please see Appendix E pages 46-63 of Pacific Power's smart grid report at the following location for a recent Washington project example:
www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=5&year=2016&docketNumber=161049

• Slide 51: EPA circulating new draft rule – is that available to PAC? Will PAC be able to (or at least try to) model the new rule as part of this IRP. Would this draft rule be a part of the base case or something different?

PacifiCorp Response:

Please refer to slides 42-43 in the September 27-28, 2018 public input meeting.

• Slide 63: should bring up state standards for coal combustion residuals in MSP as a potential cost causer and cost allocation issue
• Slide 67: How does PAC comply with CA's requirements? Does CA get a slice of PAC's full fleet, or does PAC assign a cleaner subset of its fleet?

* Required fields

PacifiCorp Response:

PacifiCorp's compliance obligation in California is based on a system emission factor that accounts for all the resources which serve PacifiCorp's load. The system emission factor is then applied to California's share of retail load to determine the associated emissions. In addition to retail load in California, PacifiCorp also has a compliance obligation for transfers made into California via the EIM and wholesale sales.

- Slide 71: clearly we'll want to spend more time on the many efforts to model shutdowns / RH compliance. I thought Friday was a good start to that conversation. It seems to me that the first filter should be whether and when to shut down a coal plant for economic reasons, then see what RH obligations are left over.

PacifiCorp Response:

Please see portfolio development discussions in the September and October 2018 public input meeting materials.

- Slide 85: I second Fred's question about duct firing. What does that add and what does that take away? More capacity for less efficiency? Also, how would costs shift if proxy resources were sited on brownfields? (Only worth exploring if it's clear that brownfield sites are available for each type of proxy resource)

PacifiCorp Response:

Duct firing adds peaking and reserves capabilities at a low fixed cost. The heat rate for duct firing would be equal to that of a modern, conventional gas-fired boiler and steam turbine. Variable costs would be equal to or lower than for existing peaking and reserve resources. The total cost of duct firing for peaking and reserves would be low because duct firing fixed costs would be low and variable costs would seldom be incurred. Duct firing does not have significant impacts on the combined cycle production or efficiency.

Proxy combined cycle resources at brown field sites are expected to be 70% to 87% of the cost of the same resources at a green field site. The cost of land and out-side-the-fence infrastructure is lower at brown field sites. Proxy sites could include Currant Creek or existing coal-fueled generating facilities.

- Slide 86: why was the consultant RFP not public? Also, to confirm, will PAC allow the consultant access to information it gained through its recent wind and solar RFPs?

PacifiCorp Response:

PacifiCorp competitively bid the consultant Request for Proposal (RFP) in accordance with Company policy. PacifiCorp did not, and does not intend to, allow the consultant access to information gained through recent wind and solar RFP's. However, prices provided by the consultant were compared to pricing from recent wind and solar RFP's, and for the base design used, the consultant's prices were found to be in line with bid prices.

- Slide 93: Good conversation; would be useful to highlight the differences between integration costs and this intra-hour dispatch credit. If we're coming back to this in future meetings, feel free to say so for the following questions.

PacifiCorp Response:

Please see discussion of Intra-Hour Flexible Resource Credit at the September and October 2018 public input meetings, and the presentation on the Flexible Reserve Study cost results from the September 27-28, 2018 public input meeting.

- Slide 96: I think the intra-hour credit is a good idea, and well-honed given the limitations PAC faces with its modeling tools and available data. Would encourage a thicker 0 line on the graph, or at least a y axis that includes a zero line.
- Slide 96: I'd encourage a simplified example of how this credit gets calculated. An illustrative example using the graphs in slides 95 and 96 would be helpful.

PacifiCorp Response:

Please see slide 33 of the September 27-28, 2018 public input meeting presentation for information on how the Intra-Hour Flexible Resource Credit is calculated.

- Slide 97: Sensitivity for dispatch credit – how big of a deal is this value?

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PacifiCorp Response:

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 part of its portfolio development on an informational basis in the 2019 IRP. PacifiCorp does not plan to apply the Intra-hour Flexible Resource Credit in modeling.

- Slide 97: If this credit is calculated based on historical data, how will PAC estimate a credit for proxy resources?

PacifiCorp Response:

Please see discussion of Intra-Hour Flexible Resource Credit at the September and October 2018 public input meetings.

- Slide 97: I'm curious about interactive effects of the integration costs for renewables. May not be significant enough to worry about, but I can envision a situation where renewables are 'paying' an integration cost, then their variability is opening up dispatchable units to follow the market, earning a bigger intra-hour dispatch credit than they might have without renewables. The opposite might also be true.

PacifiCorp Response:

In the IRP analysis, integration cost based on the cost of holding operating reserves is included in the portfolio selection decision in SO. When the selected portfolio is evaluated in PaR, the associated reserve requirement accounting for a variable energy resource additions is included in the model. This increase in reserve requirement would increase the value of any dispatchable resources that are selected. The current integration cost does not account for any interactions with EIM, which could include the cost of intra-hour variations in variable energy resources or the incremental benefits of dispatchable energy resources that are set aside. At this time it is unclear what the net effect might be. These interactions are part of the uncertainty surrounding the intra-hour flexible resource credit values that led to it being used for informational purposes only at this time, rather than for portfolio selection.

- Slide 113: How does market reliance factor into the PRM study? The concept of correlated parameters in slides 103-6 highlighted to me that there may be other tools or ways to model FOT availability besides a conservative estimate of a proxy resource. For example, if I understood the study, PSE did a regional LOLE-type analysis to estimate its risk of market reliance. PSE looked at the modeled moments of regional shortage to see if PSE was exposed to the shortfall based on their load, their assets and a prorated amount of market availability.

PacifiCorp Response:

PacifiCorp assumes a planning limit for FOTs when conducting its reliability studies to inform the planning reserve margin. Please see September 27-28, 2018 public input meeting for additional methodology and results discussion.

- Slide 117: There was a good question on how off-system resources being are represented in which models and studies. Might be worth being clear on that; perhaps a table with all the studies (Randy's walkthrough of the approach and stack of runs was verbal, and I didn't track it perfectly).

PacifiCorp Response:

Off-system resources for all of Western Electricity Coordinating Council (WECC) are represented in the Aurora price model which provides price inputs to the IRP models. In the IRP models, off-system resources are the source of market energy and capacity purchased in the form of FOTs. Off-system resources are not otherwise modeled.

Question outside of slides: I understand that PAC is considering moving towards a nodal day-ahead scheduling model with the expectation that doing so will produce fairly significant power cost savings. Will PAC talk about movements toward those tools or any other operational efficiencies they're exploring within their IRP?

PacifiCorp Response:

Within the IRP, as discussed in the June 2018 Washington state-specific input meeting, PacifiCorp has been exploring options for its modeling software to address a number of items, including improved performance and run times, and intra-hour modeling capability. No readily available replacement option has been identified to date. PacifiCorp will continue to explore and evaluate options in addition to enhancements of its existing modeling software.

Also, please let me know whether providing feedback in this format, and with this detail, is constructive for the IRP team. I welcome any ideas that will make this more useful from the company's perspective.

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.

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

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

Thank you for participating.

* Required fields