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 9/7/2018

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Address: 1300 S Evergreen Park Dr. SW

City: Olympia State: WA Zip: 98504

Public Meeting Date comments address: **9/27/2018** ☐ 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 (117-slide PAC presentation).

A note on process: As most of the participants have acknowledged, the interest of getting good analysis included in the slides has to be balanced with providing lead time with meeting materials. This balance was clearly not achieved in the September meeting, as materials were emailed to the stakeholders at 6:23 p.m. the day before a meeting. If the company takes stakeholder participation seriously and views in-person participation as the most efficient venue for hearing and responding to questions and feedback, the company must provide these materials with the lead time needed for stakeholders to provide useful comments and questions. I encourage the company to distribute meeting materials two full business days prior to the two-day meetings.

My apologies for missing these September meetings. Fortunately, other UTC staff were able to attend, and I talked with them about the proceedings.

I understand that there was a webinar or similar meeting earlier this month involving OPUC that discussed the coal study. I would appreciate a copy of these meeting materials or presentations. Please provide them, or point me in the right direction if these materials are available elsewhere.

Slide 7: Burns and McDonnell's study looks at a generic point within each state for solar and wind. I understand the need for a proxy, but am curious about how this proxy is determined for resources which are so dependent on location.

* Required fields

Slides 10-11: I'd have expected some non-zero variable costs for pump storage and CAES. Is assuming zero variable costs common for these resources? Also, I believe it was in a previous meeting that we discussed representing Li-Ion storage degradation as a variable cost. How does PAC model these kinds of factors, if not in these resource characteristic inputs?
Slide 13: This conversion factor of 1.32 DC = 1 AC was higher than I would have expected. Please provide some additional background on this conversion factor. What are the factors that go into its calculation? Does this have to do with sizing the panel numbers to about 125% higher than the inverter capacity to keep inverter efficiency up? Would this conversion factor be different from state to state?
Slide 14: Capital cost estimates are "based on" the B&M assumptions. What else goes into PAC's cost estimates?
Slide 15: Based on PAC's experience and available information, is it expected that Li-Ion batteries will cycle once per day? How large of an assumption is this when estimating the total benefit of batteries?
Slide 30: Are the duct firing rows here the costs for just duct firing? It seems like the MW nameplate is for just the duct firing component, which is less efficient than a normal CCCT. Why is the heat rate the same for both rows?
Slide 32: I understand that PAC has moved away from including the intra-hour flexible resource credit. I do not have a strong opinion on this issue, but would encourage the company to include in the IRP some narrative explaining the concept, how and why it was developed, how it was used in the final analysis and why.
Slide 38: Looks like you address the intra-hour credit and variable cost piece here a bit. Sounds like work is still being done.
Slide 46: I agree with OPUC staff's position (if I understand it correctly) that a $0 carbon price until 2030 in the base case is tenuous. The acknowledgement letter for PAC's 2017 IRP clearly communicated the expectations of a majority of the WUTC's commissioners. I am unclear on how or why PAC would use a carbon price risk other than the one identified in the acknowledgement letter, but it could be that I am incorrect in thinking that the best way to "incorporate the cost of risk of future greenhouse gas regulation in addition to known regulations in its preferred portfolio" is to use that social cost of carbon forecast as a base case input.
Slide 51: The previous slide highlights that flexible resources will be more valuable as more solar comes onto the grid. If thermal resources are expected to ramp more and more, this new operation should affect the plants' average heat rate. Is this changing dispatch pattern figured into the fundamentals price staring in month 49? Or is the modeled future dispatch of these plants not significantly different than the historical data used to calculate fundamentals-based power costs?
Slide 53: What is driving the flattening of prices at ~2027 and ~2034? This pattern appears in the gas price forwards as well. Is this a boom/bust cycle for gas that percolates into power cost forecasts? What is causing this pattern in the 2019 IRP but didn't cause this pattern in the 2017 IRP?
Slide 61: I'm puzzled by how Segment A both satisfies a transmission customer service request but also is not close to fully subscribed. What was the capacity of this line before this project is completed? How much of the existing capacity is subscribed? Who pays for any unsubscribed capacity?
Slide 63: $679.2 million / 140 miles = $4.8 million/mi. How does this compare to similar projects?
Slide 67: How does NTTG model its needs? Is PAC intending to move this analysis to a different modeling tool? If so, why?
Slide 78: I wish I hadn't missed this explanation in person. I do not understand the column labels in this table. It seems like it's taking an average or levelized flexible reserve cost for slivers of the 20 year timeframe. What does this tell us? Are the cost inputs for SO and PAR done on a year-by-year basis such that wind added in 2020 will have a very low reserve cost, and wind added in 2030 will have a much higher cost?
Slide 79: I would appreciate a table clarifying when PAC is applying an intra-hour flexibility credit to a case/scenario/sensitivity, and when it is not.
Slide 87: Why is the Capacity Contribution study year 2030? Why was it 2020 in the 2017 IRP? What prompted the change that looks out almost a decade into the future? Also, what projects are included in the "planned wind and solar" that is included in the study? I'm looking for an understanding of how likely it is that these planned resources will really be part of the system in 2030. Are all of those projects firm, with executed contracts, clear paths to permitting and interconnection, available transmission, etc? Are any retirements of any coal or other facilities also included in this study?
Slide 89: What changes were made to the LOLP shape, or what inputs have moved that have caused a change to the LOLP shape? Why is western solar more valuable for LOLP?
Slide 93: Why does east fixed tilt solar outperform east single tracking solar in the early afternoon?

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Slide 95: This is an interesting graph. I appreciate the context. It's surprising to see such a steep slope for PAC's study relative to other studies. I would have guessed that PAC's large service territory might create a locational diversity benefit that would cause that slope to be less steep compared to other utilities, and yet this graph shows that I'm off. What am I not considering? Also, would this line look different for east solar vs west solar?
Slide 98: What are the planning assumptions for the WUTC-requested WCA model runs? I would greatly appreciate discussing this soon, before the company runs this sensitivity. An analysis was performed for the last IRP, but the assumptions underpinning that analysis did not meet staff's expectations.
Slide 101: In the first bullet, what does "consider impacts on system reliability" mean? Is this an LOLP value, an output from PaR? What are the three different price/policy scenarios?
Slide 103: I'm encouraged to see that PAC is including a portfolio optimized based on a social cost of carbon. The results will only be comparable to other portfolios if the company provides the price and risk outputs for both the SCC carbon assumption and the base case carbon price assumption. Please provide PVRRs for these comparable portfolios with both carbon pricing assumptions. For example, what is the cost for the base case portfolio with a SCC assumed, and what is the cost for the SCC-optimized portfolio with the base case carbon price assumed?
Slide 109: PAC's choice to bundle DSM measures by $10 is perplexing. I appreciate that the model cannot handle the optimized selection of each DSM measure for each state, and hence that bundling is necessary. However, I have not been given a satisfactory reason for why PAC thinks the same $10/bundle granularity is needed in the $100s. I strongly encourage the company to apply more granularity where it is useful – in the $20-70 range. Deciding not to provide granularity where it is needed means the model will either leave cost-effective conservation un-selected, or select some bundled measures which are not cost-effective – either of which means the company risks running afoul of their obligation to pursue all cost-effective conservation in Washington.
Slide 109: I am not clear on how a point price and the load shape is determined for each bundle. Is the price point a weighted average based on conservation potential and price for each bundle? Is it simply the mid-point of each $10 bundle?
Slide 111: What is a project adder?
Slide 113: My point about bundle granularity is evidenced somewhat in this slide. If the levelized cost is $40, the estimated technical achievable potential is about 4 million MWh. If it's closer to $45, the potential is closer to 4.5 million. Half a million MWh in the 'noise' of the bundles is a lot of potential savings to gloss over.
Slide 114 shows that bundles $100-10,000 represent 17 bundles in the model, but represent about as much potential savings as the three bundles $30-50. Why is this modeling approach preferred?

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.
Please change the DSM bundling to provide more granularity where the the marginal cost-effective DSM bundle is likely to be. I would guess that this is in the $30-60 range. An illustration of how this might be implemented is in the table below.

Current DSM cost bundles	Proposed DSM cost bundles
<= 10	<=20
10-20	20-25
20-30	25-30
30-40	30-32
40-50	32-34
50-60	34-36
60-70	36-38
70-80	40-42
80-90	42-44
90-100	44-46
100-110	46-48

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110-120	48-50
120-130	50-52
130-140	52-54
140-150	54-56
150-160	56-58
160-170	58-60
170-180	60-62
180-190	62-64
190-200	64-66
200-250	66-68
250-300	68-70
300-400	70-80
400-500	80-100
500-750	100-200
750-1000	200-500
>1000	>500

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

Thank you for participating.

* Required fields