BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1794

In the Matter of PACIFICORP, dba PACIFIC POWER, Investigation into Schedule 37 - Avoided Cost Purchases from Qualifying Facilities of 10,000 kW or Less	COMMUNITY RENEWABLE ENERGY ASSOCIATION AND RENEWABLE ENERGY COALITION'S COMMENTS REGARDING CONTINUING PROCEEDING

I. INTRODUCTION AND SUMMARY

The Community Renewable Energy Association ("CREA") and the Renewable Energy Coalition (the "Coalition") (collectively the "Joint QF Parties") file these comments urging the Oregon Public Utility Commission (the "Commission" or "OPUC") to expeditiously resolve one discrete issue for the remainder of this proceeding: What is the renewable resource deficiency date for PacifiCorp's (or the "Company") avoided cost rates? The Joint QF Parties believe it is possible, meaningful, and valuable to set a new set of avoided cost prices that would be effective until the new avoided cost prices are put in place following PacifiCorp's 2017 integrated resource plan ("IRP") process.

In addition, the Commission should change PacifiCorp's renewable resource sufficiency period **now** pending the final order in this proceeding or the Company's 2017 IRP. The Commission has been presented with overwhelming evidence that PacifiCorp is planning on issuing a request for proposal to acquire renewable resources by 2020, and rates should be modified to reflect that reality. Regardless of whether the Commission issues a final order in this case or waits until the completion of PacifiCorp's 2017 IRP, the Commission should

immediately modify the Company's renewable rates to include a 2020 rather than a 2028 renewable resource deficiency date.

Failing to modify PacifiCorp's rates until another eight months to over a year (the post-2017 IRP rate change would likely occur sometime in early to late 2018) would result in PacifiCorp's avoided cost rates continuing to be set too low for an indefinite period of time. This would potentially result in qualifying facilities ("QFs") being unable to defer **any** of the over a thousand megawatts ("MW") of renewable power that PacifiCorp has been planning, and is continuing to plan, on acquiring in the next few years. The urgency of taking immediate action to correct PacifiCorp's rates is confirmed by PacifiCorp's decision to issue a renewable Request for Proposal ("RFP") with a final short list of winning bidders filed with the Commission on January 16, 2018, which is after new rates would likely be set after the acknowledgement of the 2017 IRP.

Despite the QF Parties' investment in significant time and resources based on the assumption that they would be able to obtain timely and relevant resolution of the appropriate avoided cost rates in this case, the Commission had indicated that it may elect to close this docket and leave PacifiCorp's abnormally low avoided cost rates in place until some undetermined date in the future. To keep this proceeding open, the Commission stated that any new avoided cost rates would need to be in effect for at least one quarter, and that any proposal to continue this docket should "demonstrate the need and ability to address a specific, well-defined set of issues now rather than during the review of PacifiCorp's 2017 IRP and associated avoided cost filing."[1] This can be accomplished post haste.

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[1] Re PacifiCorp dba Pacific Power Investigation into Schedule 37 - Avoided Cost

To satisfy the Commission's request for specific and well-defined issues, the Joint QF Parties propose the scope of the proceeding be limited to only one issue: What is the appropriate renewable resource deficiency date? Issues related to the non-renewable rates and costs and inputs are more complex. In addition, regardless of the decisions in this case, PacifiCorp's non-renewable rates are significantly lower than the renewable rates, which diminishes the usefulness of any such review. Discussions related to the non-renewable resource sufficiency date will be relevant and can provide necessary background for the renewable rates because, for example, the date of thermal retirements and the next gas generation plant impacts planned renewable resource acquisitions. However, to expeditiously resolve the case, the Joint QF Parties are willing to drop the issue and no longer request that the Commission select a specific non-renewable resource deficiency date.

The need to address PacifiCorp's renewable avoided cost rates is simple: these rates have been disputed for over a year and are preventing cost effective QFs from selling power to PacifiCorp. During this time, PacifiCorp has consistently stated in numerous forums before and outside of the Commission that it is planning on acquiring, and has taken efforts and will continue to act with the intention to acquire renewable resources in the immediate future. Over this same period PacifiCorp has claimed in proceedings related to the Public Utility Regulatory Policies Act ("PURPA") that it does not need renewable power, and succeeded in convincing the Commission to set "interim" rates assuming a 2028 resource sufficiency date.

PacifiCorp's rates have been inaccurately low for over a year, which has and will continue to distort the regulatory process and power markets. Both ratepayers and independent

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Purchases from Qualifying Facilities of 10,000 kW or Less, Docket No. UM 1794, Order No. 17-176 at 4 (May 18, 2017).

power producers have been harmed as non-utility generators have been prevented from selling power to a utility that may be in the process of acquiring an unprecedented amount of renewable resources for rate base. As is explained in the attached testimony of John Lowe of the Coalition, Brian Skeahan of CREA, and Gary Marcus of Falls Creek Hydro, QFs that are being harmed include both potential new facilities as well as existing projects. Some of these currently operating projects may need to shut down their operations, if they are unable to enter into contract renewals or otherwise sell their power. Without Commission action in this proceeding, PacifiCorp may acquire up to 1,270 MWs of renewable power while new QFs cannot be built and small operating projects like Falls Creek Hydro shut down.

Waiting until the end of PacifiCorp's 2017 IRP may be too late. PacifiCorp's 2017 IRP currently is expected to be completed around the end of the year, which could mean that new rates would be effective in early 2018. This assumes, however, that PacifiCorp's IRP will be acknowledged on a timely basis, which infrequently occurs, and that PacifiCorp's post-IRP avoided cost update is non-controversial (this case demonstrates how long of a delay can occur with a controversial update). The practical result of waiting until the completion of the 2018 IRP will be at least a two-year period (and potentially much longer) in which avoided cost rates were set too low.

Even more relevant, PacifiCorp is in the process of issuing a renewable request for proposal ("RFP"), which could potentially be completed by early 2018. PacifiCorp is not waiting on its IRP to be completed, and neither should any changes in its avoided cost rates. If the RFP goes forward and PacifiCorp purchases the over 1,000 MW of power that it says it needs, then PacifiCorp may argue that the results of that RFP impact its sufficiency period and the date should be kept in the late 2020s.

Essentially, we cannot know the outcome of either PacifiCorp's IRP or its next RFP, and one possible result is that delaying this proceeding will have the practical result of PacifiCorp acquiring the largest amount of renewable resources ever and QFs not being able to sell power to defer any of that power because the avoided cost rates failed to accurately reflect PacifiCorp's actual resource plans for over a two-year period.[2] Whether through superior planning, better legal advice and strategy, good fortune, or some combination, PacifiCorp has been able to consistently move forward with plans to acquire renewable resources, but effectively preclude PURPA projects from selling power over that same period of time. To date, PacifiCorp has won the Oregon PURPA wars.

In addition to PacifiCorp's remarkable ability to have its avoided cost rates include a deficiency period completely divorced from its actual plans, there is the juxtaposition between PacifiCorp and Portland General Electric Company ("PGE"). PGE also claims to have a large renewable resource need, and (unlike PacifiCorp) included these plans its pre-IRP analysis. PGE is also planning on issuing an RFP for renewable resources, but is attempting to seek acknowledgment of is renewable resource need prior to IRP acknowledgment. PGE's avoided cost rates more accurately reflect its actual resource plans with a 2021 renewable resource deficiency date, while PacifiCorp's assume a 2028 renewable resource need. Thus, QFs located

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[2] PacifiCorp's current rates became effective in August 2016. The last significant new QFs that have entered into power purchase agreements with PacifiCorp were in June 2016, and since then there have been four executed contracts (three contract renewals, two of which were under 100 kW, and only one new 3 MW geothermal project whose contract was the result of a settlement of a complaint and was already operating at the time of contract execution). Re PacifiCorp, dba Pacific Power Information Filing of Qualifying Facility Contracts or Summaries per OAR 860-029-0020(1), Docket No. RE 142.

in PacifiCorp's service territory find it more economic to purchase transmission to wheel their power and sell it to PGE. Depending on your perspective, this outcome is either benefiting PGE's ratepayers (deferring potentially more expensive and risky utility owned generation) or harming PGE's ratepayers (requiring them to be served with potentially more expensive non-utility owned generation). Either way, QFs located in PacifiCorp's service territory should not have to pay additional costs to wheel their power long distances when both PGE and PacifiCorp are planning on new renewable resource acquisitions right now.

The speed in which PacifiCorp's March 1, 2016 avoided cost rate filing has been processed lies in stark contrast to the Commission's prior actions to act rapidly to protect utilities from potential "harm" associated with the need to buy power from QFs. For example, the Commission quickly lowered the eligibility cap for solar QFs and provided the interim relief requested by Idaho Power Company and PacifiCorp.[3] The Commission also temporarily eliminated Idaho Power's obligation to enter into standard contracts above 100 kW just 18 days after alleging harm associated with an alleged avalanche of new wind projects (which failed to ever materialize).[4] Recently, despite a reasonable expectation that rates would change in late June 2017, the Commission acted in less than one month to lower PGE's rates in that utility's last annual update.[5] Now that PacifiCorp's rates have been set too low for almost a year, the

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3 Re Idaho Power Application to Lower Standard Contract Eligibility Cap and to Reduce the Standard Contract Term, for Approval of Solar Integration Charge, and for Change in Resource Sufficiency Determination, Docket No. UM 1725, Order No. 15-199 at 2-3, 6-9 (June 23, 2015); Re PacifiCorp, dba Pacific Power's Application to Reduce the Qualifying Facility Contract Term and Lower the Qualifying Facility Standard Contract Eligibility Cap, Docket No. UM 1734, Order No. 15-241 at 3 (Aug. 14, 2015).

4 Re Idaho Power, Docket No. UE 244, Order No. 12-042 at 1-2 (Feb. 14, 2012).

5 Re PGE Application to Update Schedule 201 Qualifying Facility Information, Docket No. UM 1728, Order No. 17-177 at 1 (May 19, 2016).

Commission should at least issue a final order at some point, and do so in less than a year and half. In the interim. and pending final resolution of this case or the 2017 IRP, rates should be set assuming a 2020 renewable deficiency date.

The Commission can issue an order on a timely basis prior to September and provide QFs an opportunity to defer some of PacifiCorp's planned renewable resource acquisitions. This case has included numerous filings and two public meetings, and there is no need for much additional process. If the Commission does not just set the renewable deficiency date at 2020 immediately, then the Joint QF Parties propose the following schedule for the remainder of this case:

Joint QF Parties Provide Testimony to PacifiCorp	May 30, 2017
Joint QF Parties Formally File Testimony	June 12, 2017
PacifiCorp Files Rebuttal Testimony	June 20, 2017
Hearing	July 5 or 7, 2017
Post Hearing Brief	July 14, 2017
Final Order	August 4, 2017
New Rates Effective	August 7, 2016

To facilitate processing this case to a prompt resolution, the Joint QF Parties' testimony is attached. This testimony has been nearly completed for months while we have awaited resolution of the discovery disputes and scope of the proceeding. The Joint QF Parties will accept discovery requests from PacifiCorp on this testimony immediately. The testimony was drafted based on an assumption of a broader set of issues, but can be limited if a more narrow scope of the proceeding is adopted.

II. BACKGROUND

The history of this case is voluminous, but some basic information is necessary to understand why this case should be expeditiously prosecuted to completion and why PacifiCorp has a renewable resource need that should be reflected in rates as soon as possible.

On March 1, 2017, PacifiCorp filed new avoided cost rates following its 2015 acknowledged IRP.[6] While generally this filing is due 30 days following IRP acknowledgment, PacifiCorp made this filing unusually quick and only one business day after its IRP was acknowledged on February 29, 2016. While rates would generally be effective in about two months, PacifiCorp requested an effective date of April 1, 2016 (the date that the avoided cost rate change would ordinarily be filed). PacifiCorp proposed a reduction in its renewable avoided cost rates largely because the rates were entirely based on market prices with the next renewable resource acquisition beyond the 20-year action plan. The Commission's acknowledgment order for the 2015 IRP only addressed issues regarding PacifiCorp's short-term action plan and did not address the year of deficiency, and recognized that the passage of the changes to the Renewable Portfolio Standard "likely will affect PacifiCorp's action plan contained in its 2015 IRP."[7]

The Commission did not approve PacifiCorp's rates after opposition from Staff and QF parties, but instead directed PacifiCorp to re-file its avoided cost rates in light of SB 1547. The Commission's decision at the March 22, 2016 public meeting rejected the underlying assumption

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6 Unlike the May 1 updates, the IRP related update is an opportunity for Staff and interested parties to challenge the Company's inputs, assumptions and resource sufficiency date. See Re Commission Investigation Into QF Contracting and Pricing, Docket No. UM 1610, Order No. 14-058 a 2, 25-26 (Feb. 24, 2014) (adopting May 1 update process); Re Investigation Relating to Elec. Util. Purchases from QFs, Docket No. UM 1129, Order No. 05-584 at 36-37 (May 13, 2005); Re Investigation Relating to Elec. Util. Purchases from QFs, Docket No. UM 1129, Order No. 06-538 at 44 (Sept. 20, 2006).

7 Re PacifiCorp 2015 IRP, Docket No. LC 62, Order No. 16-071 at 1 (Feb. 29, 2016). The Commission also specifically did not address the Coalition's arguments that PacifiCorp's year of deficiency was inaccurate. Re PacifiCorp 2015 IRP, Docket No. LC 62, REC Comments at 4-5 (Aug. 27, 2015); Re PacifiCorp 2015 IRP, Docket No. LC 62, Public Meeting from 1:23 to 1:26 (Dec. 17, 2015).

of PacifiCorp's initial filing claiming that the Company was renewable resource sufficient for the entire planning horizon of 20-plus years. The Commission directed:

> This order memorializes our decision, made and effective at the public meeting on March 22, 2016, to: (1) not approve the filing made by PacifiCorp, dba Pacific Power, to update its Schedule 37, Avoided Cost Purchases from Qualifying Facilities 10,000 kW or less; and (2) direct PacifiCorp, Staff, and interested parties to work together and propose an expedited and non-contested case process to update PacifiCorp's avoided costs in light of the passage of SB 1547.[8]

The obvious impact of the passage of SB 1547 is to drastically shorten the renewable sufficiency period, and the Commission's primary intent was to correct that mistaken assumption in PacifiCorp's initial filing. To obtain passage of SB 1547, PacifiCorp, stated that the Oregon renewable portfolio standard revisions "incents early action through its REC banking provision, which allows utilities and customers to benefit from recently extended federal tax credits. HB 4036 enables at least **225 MW** of additional low-cost renewable procurement **over the near-term**."[9] Similarly, PacifiCorp informed the Commission at its January 29, 2016 hearing regarding the RPS revisions that the bill would provide PacifiCorp "an opportunity to procure over **600 MW** of low-cost renewable resources **over the near-term."**

Throughout this entire litigation in both UM 1729 (in which the avoided cost rate filing was originally made) and UM 1794 (this docket opened to address the Company's avoided cost rates), PacifiCorp has had an informational advantage, which it has used to its advantage. For example, PacifiCorp issued its 2016 Renewable RFP on April 11, 2016. PacifiCorp did not inform the QF parties about the 2016 Renewable RFP prior to its issuance. This meant that

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8 Re PacifiCorp, dba Pacific Power, Schedule 37 Avoided Cost Purchases from Eligible QFs, Docket No. UM 1729(1), Order No. 16-117 at 1 (Mar. 23, 2016).

9 Testimony of Scott Bolton to the House Energy and Environment Committee (SB 1547 was originally HB 4036).

PacifiCorp's early filing of its avoided cost rate update on May 1, 2016 with a proposed effective date of April 1, 2016, had the practical effect of keeping this key information from at least the QF Parties while critical decisions were being made at the March 22, 2016 public meeting to review the rate filing. Specifically, if PacifiCorp had either waited the normal 30 days to update its avoided cost update after its IRP acknowledgement, or even let the parties know before the public meeting that it was going to issue an RFP in a couple weeks, then the QF parties would have been able to address this at the public meeting. It was very relevant that PacifiCorp was planning on issuing a RFP for renewable resources at the same time it was filing avoided cost rates based on the assumption that it would not acquire renewable resources for decades.

The Commissioners were deeply skeptical of PacifiCorp's resource sufficiency date, as well as the speed upon which it was filed, as demonstrated by the following exchange at the March 22, 2016 public meeting:

Chair Ackerman:	Do you think there is still a valid sufficiency/ deficiency demarcation to be had for renewable resources in light of [SB] 1547?
Bryce Dalley:	I don't think that that has been fully evaluated in the context of an IRP. The legislation is fresh. We go through an extensive --
Commissioner Savage:	Do you agree that it's new information?
Bryce Dalley:	Absolutely. It is new information. And it will be certainly evaluated as part of our upcoming IRP. We are planning to file an IRP Update here at the end of the month.
Commissioner Bloom:	Okay, you're going to file by the end of the month?
Bryce Dalley:	Correct. And that's an IRP Update so it doesn't have the same rigor or stakeholder involvement your typical IRP. . . . And these things will be

fleshed out as part of those processes, no question . . . . But to answer your question directly Chair Ackerman, I don't believe the demarcation of sufficiency/deficiency has changed from what was recently acknowledged by the Commission.

Commissioner Savage: Oh, I disagree.

Commissioner Bloom: Bryce --

Chair Ackerman: You know, you've got to be kidding.

Commissioner Bloom: Bryce, Bryce --

Chair Ackerman: I am trying to figure out whether you guys are just disingenuous or cynical and disingenuous and I am coming to the conclusion it's both cynical and disingenuous.

Commissioner Bloom: Bryce, would you --

Chair Ackerman: You filed this on what March 1, is when you filed these avoided cost filings. And when did the legislature approve [SB] 1547? Do you remember the date?

Bryce Dalley: I believe it was signed by the Governor on March 8.

Chair Ackerman: Okay. So as you were testifying to the legislature, your company, about what your needs were going to be for renewable resources to fill the new RPS requirement, somebody in PacifiCorp was making the decision to make this filing?

Bryce Dalley: . . . We were required to submit a filing using the latest acknowledged, which was a day before, IRP and provide our avoided cost update consistent with that acknowledgement. . . . We are a culture of compliance. We comply with the rules and my understanding, Chair Ackerman, is if we did not

> make this filing we would not be within compliance with your rules. [10]

The parties spent valuable time attempting to reach a settlement and mutually agree upon avoided cost rates, but were unable to reach resolution. In addition, PacifiCorp completed its 2016 Renewable RFP in July 2016.

The Commission approved PacifiCorp's current avoided cost rates based on a 2028 renewable and non-renewable resource deficiency date at the August 16, 2016 public meeting. Prior to that public meeting, PacifiCorp had agreed that it needed renewable resources soon and its public position was that the renewable resource sufficiency date should be **2018**, but using the lower 2015 IRP Update cost inputs and assumptions.[11] PacifiCorp surprised all the QF parties at the August 16, 2016, public meeting and argued in favor of a later date on the grounds that its 2016 RFP had been completed and that it would not be acquiring renewable resources for potentially a decade or more.[12]

PacifiCorp's decision to change is position at the last minute worked, and the Commission adopted the 2028 date on at least an interim basis pending completion of "an expedited contested case proceeding shall be opened to allow a more thorough vetting of the issues raised in this proceeding and possible revision to Schedule 37 avoided cost prices on a prospective basis."[13] The 2028 date was selected on a potentially temporary basis because that

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10 Re PacifiCorp, dba Pacific Power, Application to Update Schedule 37 QF Information, Docket No. UM 1729(1), Public Meeting at 33:00 to 40:30 (Mar. 22, 2016).

11 Re PacifiCorp, dba Pacific Power, Application to Update Schedule 37 QF Information, Docket No. UM 1729(1), PacifiCorp Comments at 1 (July 22, 2016).

12 Re PacifiCorp, dba Pacific Power, Application to Update Schedule 37 QF Information, Docket No. UM 1729(1), Order No. 16-307 (Aug. 18, 2016).

13 Re PacifiCorp, dba Pacific Power, Application to Update Schedule 37 QF Information, Docket No. UM 1729(1), Order No. 16-307 at 1 (Aug. 18, 2016).

was the date that PacifiCorp's renewable energy certificate bank would be depleted, without other actions. PacifiCorp went to great lengths to explain that it would not be acquiring physical resources for potentially decades and no need for physical resources because the Company would just be buying renewable energy certificates.[14]

The Joint QF Parties preference was not to have a contested case, but have the rates set correctly in the first place. In reliance upon the Commission's willingness to consider revising the rates and opening a contested case without explicit limitations on the scope, the Joint QF Parties aggressively sought to review, vet and challenge PacifiCorp's renewable and non-renewable rates in this proceeding. Prior to the August 18, 2016 order, the Coalition, the CREA, Renewable Northwest, Obsidian Renewables and Cypress Creek Renewables had already opposed PacifiCorp's filings with five separate sets of comments, as well as preparing for and attending settlement conferences and two disputed two public meetings. After this contested case proceeding was opened, the Joint QF Parties invested considerable effort in discovery and preparation of testimony, including taking the unusual step (for QF parties with limited budgets) of retaining an outside expert witness. Discovery disputes resulted in three discovery conferences with the Administrative Law Judge, and the Joint QFs filing about a dozen separate discovery and procedural related legal pleadings (motions to compel, request for certifications, responses, replies, extensions of time, etc.). When taking a position, Staff sided with the Joint

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14 Re PacifiCorp, dba Pacific Power, Application to Update Schedule 37 QF Information, Docket No. UM 1729(1), Public Meeting (Aug. 16, 2016). The Joint QF Parties urged the Commissioners to listen to the public meeting to determine if any of PacifiCorp's justifications for a later date remain valid today. E.g., Mr. Link explaining that "the analysis that we have performed even after the passage of SB 1547 suggests and actually reinforces that strategy to achieve compliance over the long term remains valid and in fact one that the company will continue to pursue by ongoing RFPs to test the market for renewable energy credits.") Id. at 49:13.

QF Parties on all the discovery disputes and arguments regarding the scope of the proceeding.

Given that the Joint QF Parties were unable to compel additional information in discovery, the Joint QF Parties testimony has been substantially unchanged and therefore completed since November 2016. Since March 2016, the Joint QF Parties and other QF advocates have submitted almost twenty legal pleadings, engaged in settlement talks, attended three discovery conferences, participated in two public meetings, and prepared three pieces of testimony for four witnesses. After all this time and effort, instead of briefing to obtain a final resolution, the Joint QF Parties are briefing whether or not they will even be provided an opportunity to address the merits of PacifiCorp's resource deficiency date. In the end, if the Commission does not simply set the renewable deficiency date at 2020 pending the completion of the 2017 IRP, the Joint QF Parties deserve their "day in court" to obtain a Commission resolution on the appropriate renewable resource deficiency demarcation.

III. ARGUMENT

1. The Commission Should Revise PacifiCorp's Renewable Avoided Cost Rates Now

The Commission should correctly set at least PacifiCorp's renewable avoided cost rates immediately, or after the end of this expedited contested case proceeding, because:

- They are unjust and unreasonable due to the failure to reflect PacifiCorp's planned and actual renewable resource acquisitions.
- Ratepayers will be harmed and Oregon law thwarted if PacifiCorp's avoided cost rates do not permit non-utility QF generators to defer at least a portion of the Company's up to 1,270 MWs of renewable resource acquisitions over the next few years.
- Independent power producers building new projects will be harmed if they are effectively precluded from selling their renewable net output during a period of major utility resource acquisitions.

- Independent power producers operating existing projects will be harmed if they are unable to sell their power at the utility's avoided costs, especially if they need to curtail their output or shut down their facilities.

- The integrity of the Commission's regulatory processes will be diminished if the Commission closes a contested case proceeding after considerable effort and input, without even providing the parties an opportunity to make their case on a matter that could result in the inability of both new and existing businesses to operate.

2. PacifiCorp Is Planning on Acquiring Major New Renewable Resources Well Before 2028

The Commission should either revisit the 2028 renewable resource deficiency date immediately with an order with a 2020 date pending the completion of the 2017 IRP or the completion of this case, or allow the Joint QF Parties an opportunity to demonstrate that an earlier date is warranted. PacifiCorp's claimed renewable resource acquisition plans in its PURPA-related Oregon regulatory filings cannot be more markedly different from the Company's public statements and actions in non-PURPA-related forums. The regulatory planning process cannot be expected to be, and has never been, a perfect predictor of actual utility resource decisions. However, the Joint QF Parties cannot recollect a time when a utility's plans articulated in PURPA proceedings have diverged so remarkably from statements in other areas and reality. The credibility of the regulatory process is diminished when the Company's PURPA rates are based on no short or medium-term need for renewable resources and are directly contradicted by PacifiCorp's aggressive efforts to obtain new generation.

In nearly every administrative forum and actual action, other than avoided cost proceedings in which the Company wants to push out the deficiency demarcation, PacifiCorp has made it clear that it intends to acquire renewable resources more quickly than 2028. For example:

- PacifiCorp's statements before the Commission and the legislature that SB 1547 "provides an opportunity to procure over 600 MW of low-cost renewable resources over the near term" and explaining that unlimited REC life and federal production tax credits make renewables about 30% less costly while those credits are in full effect.[15]

- PacifiCorp's issuance of its 2016 RFP demonstrated a commitment to obtain new renewable resources in the near term.

- PacifiCorp's statements in its updated 2017-2021 RPIP that PacifiCorp would not wait until 2024 to make its next resource acquisition, and would "continue to monitor the market to assess the optimal time for additional acquisitions for RPS compliance" instead.[16]

- PacifiCorp's statements to the Commission that PacifiCorp would issue additional Renewable RFPs in the near future and "pursue bi-lateral renewable resource opportunities if cost effective for customers."[17]

- PacifiCorp's statements in its 2017 IRP that PacifiCorp plans to build 1,100 MW of new wind projects, primarily in Wyoming, by the end of 2020, add another 859 MW of new wind capacity – 85 MW in Wyoming and 774 MW in Idaho – between 2028 and 2036, and build 1,040 MW of new solar capacity between 2028 and 2036.

- PacifiCorp's decision to immediately pursue resource acquisitions prior to the completion of its 2017 IRP, including the statement that the PacifiCorp's 2017 Renewable RFP "will seek up to approximately 1,270 MW of wind resources that can achieve a commercial operation date of no later than December 31, 2020".[18]

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15 OPUC Special Public Meeting, Oregon Clean Electricity & Coal Transition, PacifiCorp Presentation at 2 (Jan. 29, 2016). HB 4036 Public Hearing, House Committee On Energy and Environment, PacifiCorp Testimony of Scott Bolton at 57:50 (Feb. 4, 2016);

16 Re PacifiCorp RPIP, Docket No. UM 1790, PacifiCorp's Reply Comments at 5 (Oct. 28, 2016) (internal citations omitted).

17 OPUC Special Public Meeting, PacifiCorp Presentation to the Commission regarding ongoing renewable and REC RFP process with the potential of an executive session at 3 (July 26, 2016); Re PacifiCorp, dba Pacific Power, 2015 IRP, Docket No. LC 62, 2015 IRP Update at 56 ("To fully evaluate Oregon RPS compliance alternatives that consider potential near-term, time- sensitive resource procurement opportunities, PacifiCorp intends to issue requests for proposals (RFPs) seeking both REC purchase and resource procurement alternatives.").

18 http://www.pacificorp.com/sup/rfps/2017-rfp.html

In this proceeding, however, PacifiCorp has proposed to keep the 2028 renewable resource deficiency date.[19] In testimony in this case, PacifiCorp recognized that the 2028 date was not based on its acknowledged 2015 IRP or 2015 IRP Update; PacifiCorp stated that this conclusion was based on the fact that "[n]either the 2015 IRP nor the 2015 IRP Update anticipates acquiring a new renewable resource during the IRP 20-year planning horizon."[20]

Regardless of whether those statements were accurate at the time, PacifiCorp now plans to acquire a huge number of renewable resources during the first couple years of the IRP 20-year planning horizon. In other words, the entire underlying basis for PacifiCorp's support for the 2028 renewable deficiency date in testimony and at public meetings is wrong. Therefore, the Commission should either immediately change the date to 2020, and/or allow the Joint QF Parties an opportunity to present evidence in a contested case to demonstrate that a 2020 date more accurately reflects PacifiCorp's renewable resource plans.

3. Joint QF Parties' Testimony Supports an Earlier Deficiency Date

The Joint QF Parties have attached to these comments the draft testimony that has been nearly completed since November 2016.[21]

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19 Re PacifiCorp dba Pacific Power Investigation into Schedule 37 - Avoided Cost Purchases from Qualifying Facilities of 10,000 kW or Less, Docket No. UM 1794, PAC/100, Dickman/7-8 (Oct. 14, 2016).

20 Re PacifiCorp dba Pacific Power Investigation into Schedule 37 - Avoided Cost Purchases from Qualifying Facilities of 10,000 kW or Less, Docket No. UM 1794, PAC/100, Dickman/7 (Oct. 14, 2016). The Joint QF Parties suspected that PacifiCorp's actual plans to acquire renewable resources were inconsistent with this testimony, but the Joint QF Parties were unable to obtain this information in discovery in this proceeding.

21 The Joint QF Parties were awaiting the possibility of including information regarding PacifiCorp's renewable resource deficiency date and costs that may have been obtained from their motions to compel. As those motions were ultimately denied, the testimony has only been modified to reflect the events over the past six months, which make it even more clear that PacifiCorp is renewable resource deficient, including the issuance of the

The testimony of John Lowe and Brian Skeahan provide summary recommendations that the Commission should adopt new avoided cost rates, including a renewable resource sufficiency/deficiency demarcation of sometime between 2019 and 2022, a non-renewable resource sufficiency deficiency demarcation of 2021, and the costs of renewable resources should not be changed from the inputs and assumptions from the 2015 acknowledged IRP.[22] Messrs. Lowe and Skeahan address the changes since the Commission acknowledged PacifiCorp's 2015 IRP, and the practical impacts of PacifiCorp's rates. They also address that PacifiCorp's sufficiency demarcation does not correlate with its existing renewable energy credit bank because PacifiCorp will not wait until the year it is facing non-compliance to acquire new resources. PacifiCorp has historically stayed well ahead of the compliance curve and acquires renewable resources well in advance of need, and this trend should be considered by the Commission.

Messrs. Lowe and Skeahan urge the Commission to use common sense and recognize that PacifiCorp's approach in avoided cost proceedings has been to push out the date of deficiency for more than a decade. The Company's extremely low rates then reflect this inaccurate assumption that the Company has no plans to acquire new resources, which effectively bars QFs from selling their net output to PacifiCorp. In contrast, reality shows that PacifiCorp is actually in a permanent state of renewable resource deficiency and constantly looking to acquire new renewable resources.

2017 IRP.

22 Messrs. Lowe and Skeahan's testimony was drafted to address both the renewable and non-renewable rates. If the Commission accepts the Coalition and CREA's recommendation in these comments to only address the renewable sufficiency period, then the testimony regarding the non-renewable rate will only be relevant in as much as it supports the date for the renewable resource deficiency date.

The Coalition and CREA also jointly sponsored the testimony of Jeremy I. Fisher, PhD. Dr. Fisher has significant experience with utility planning models in general and PacifiCorp's 2015 IRP process in particular. Dr. Fisher will address PacifiCorp's renewable and non-renewable resource position from a least-cost perspective. His testimony was prepared based on the assumption that the Commission would want to revisit the resource sufficiency date based on the information known to the Company at the time it prepared its 2015 IRP, modified in light of the recent changes to the regulatory environment regarding SB 1547 and other major events. Dr. Fisher concludes that a principled analysis of PacifiCorp's resource position, if PacifiCorp were to act in the economic best interest of its customers, would be to acquire a major non-renewable resource in 2021 and major renewable resource between 2019 and 2022. In summary, if the Commission wants to compare the 2015 IRP with discrete and specific changes related to SB 1547 (which is what the Commission did when setting the current rates), then Dr. Fisher's testimony supports a 2020 renewable deficiency date.

Finally, the Coalition and CREA have also jointly sponsored the testimony of Gary Marcus, with Falls Creek Hydroelectric Project, L.P. ("Falls Creek"). Falls Creek has been operating since 1984 and selling power to PacifiCorp pursuant to a power purchase agreement that expires December 31, 2019. Mr. Marcus' testimony explains that, despite Falls Creek being designed with a useful life of 100 years, Falls Creek will need to shut down if its only option is to renew its contract under the current prices.

IV. CONCLUSION

The Commission should immediately set PacifiCorp's renewable resource deficiency date for 2020. The Joint Parties are not opposed to deferring resolution of this proceeding until the completion of PacifiCorp's 2017 IRP, but only if rates are set accurately now. If the Commission does not re-set the renewable deficiency date to 2020, then the Commission should expeditiously resolve the issue of the appropriate deficiency date according to the schedule proposed by the Joint QF Parties.

Respectfully submitted this 30th day of May 2017.

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Of Attorneys for Renewable Energy Coalition

Attachment A

1) **Testimony of John Lowe of the Renewable Energy Coalition and Brian Skeahan of the CREA, REC-CREA.**

2) **Testimony and Exhibits of Jeremy Fisher, REC-CREA.**

3) **Testimony and Exhibits of Gary Marcus of Falls Creek Hydro, REC-CREA.**

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1794

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER's	)
Investigation into Schedule 37 - Avoided Cost	)
Purchases from Qualifying Facilities of 10,000	)
kW or Less.	)
	)
	)

RESPONSE TESTIMONY OF

JOHN R. LOWE AND BRIAN SKEAHAN

ON BEHALF OF THE

RENEWABLE ENERGY COALITION

AND

COMMUNITY RENEWABLE ENERGY ASSOCIATION

May 30, 2017

I. INTRODUCTION

Q Mr. Lowe, please state your name and business address.

A My name is John R. Lowe. I am the director of the Renewable Energy Coalition (the "Coalition"). My business address is Renewable Energy Coalition, 88644 Hwy 101, Gearhart, OR 97138.

Q Please describe your background and experience.

A In 1975, I graduated from Oregon State with a Bachelor of Science degree. I was employed by PacifiCorp for over 30 years, most of which was spent implementing the Public Utility Regulatory Policies Act ("PURPA") regulations throughout the utility's multi-state service territory. My responsibilities included all PURPA contractual matters and supervision of other matters related to both power purchases and interconnections. Since 2009, I have been directing and managing the activities of the Coalition as well as providing consulting services to individual members of the Coalition related to both power purchases and interconnections.

Q Have you testified in previous cases before administrative agencies on energy regulatory topics?

A I have testified and been an expert witness before the Oregon Public Utility Commission (the "Commission") in numerous regulatory proceedings regarding PURPA, interconnections, and renewable energy development. I have also testified before the Washington Utilities and Transportation Commission, the Utah Public Service Commission, the Idaho Public Utilities Commission, and the Wyoming Public Service Commission on similar matters.

Q **On whose behalf are you appearing in this proceeding?**

A I am testifying on behalf of the Coalition.

Q **Please describe the Coalition and its members.**

A The Coalition was established in 2009, and is comprised of nearly 40 members most of which own and operate and some are proposing new projects. These members represent over 50 renewable energy generation qualifying facilities ("QFs") in Oregon, Idaho, Washington, Utah, and Wyoming. Several types of entities are members of the Coalition, including irrigation districts, waste management districts, water districts, electric cooperatives, corporations, and individuals.

Q **Mr. Skeahan, please state your name, employer, and business address.**

A Brian Skeahan, Community Renewable Energy Association ("CREA"), 1113 Kelly Avenue, The Dalles, Oregon, 97058.

Q **On whose behalf are you testifying?**

A I am submitting testimony on behalf of CREA.

Q **Please describe your educational and professional background.**

A I have a Bachelor of Arts in Political Science and Public Administration from the University of Nebraska, and a Master of Science in Public Administration from the University of Oregon. I had a 30-year career in the public utility industry, beginning at the Springfield Utility Board working in rates, power management and regional issues. I served as a General Manager at a municipal utility in Nebraska for seven years, at Klickitat PUD in Washington for nine years and at Cowlitz PUD for eight years. During this time I was heavily involved in renewable energy development and policy, wholesale and retail rates, and various Pacific Northwest regional power matters.

Q Have you testified in previous cases before administrative agencies on energy regulatory topics?

A I have testified and been an expert witness before the Commission in Phase II of docket UM 1610 and in docket UM 1734. I have also testified in in Bonneville Power Administration ("BPA") rate proceedings.

Q What is CREA's interest in this proceeding?

A CREA is an Oregon Revised Statutes Chapter 190 intergovernmental association. CREA is a public/private organization whose members consists of individuals, businesses, and local governments seeking to promote locally-owned renewable energy projects for all forms of renewable generation recognized in Oregon's Renewable Portfolio Standard ("RPS") (biomass, geothermal, hydropower, ocean thermal, solar, tidal, wave, wind and hydrogen). CREA is comprised of several Oregon counties which provide active participation through their county commissioners, including Sherman, Wasco, Gilliam, Harney, Hood River, Morrow, Polk, Union, Wheeler, Curry, and Wallowa. In addition to these counties, CREA's current membership includes the Mid-Columbia Council of Governments, Columbia Gorge Community College, and 25 irrigation districts, businesses, individuals and non-profit organizations who have interests in a viable community renewable energy sector for Oregon.

Q Are the Coalition and CREA sponsoring other testimony?

A Yes. The Coalition and CREA have jointly sponsored the testimony of Jeremy I. Fisher, PhD. Dr. Fisher has significant experience with utility planning models in general and PacifiCorp's 2015 integrated resource plan ("IRP") process in particular. Dr. Fisher will address PacifiCorp's renewable and non-renewable resource position from a least-cost perspective. His testimony applies his technical expertise and concludes that in light of the recent changes to the regulatory environment PacifiCorp would actually be renewable and non-renewable resource deficient much sooner than 2028. Dr. Fisher concludes that a principled analysis of PacifiCorp's resource position, if PacifiCorp were to act in the economic best interest of its customers, would be to acquire a major non-renewable resource in 2021 and major renewable resource between 2019 and 2022.

Q Are the Coalition and CREA sponsoring other testimony on the practical impact of PacifiCorp's proposed rates?

A Yes. The Coalition and CREA have also jointly sponsored the testimony of Gary Marcus, with Falls Creek Hydroelectric Project, L.P. ("Falls Creek"). Falls Creek has been operating since 1984 and selling power to PacifiCorp pursuant to a power purchase agreement that expires expire December 31, 2019. Mr. Marcus explains that despite Falls Creek being designed with a useful life of 100 years, Falls Creek will need to shut down if its only option is to renew its PPA under the current Schedule 37 prices.

Falls Creek's situation is due to uniquely harmful aspects of Oregon's PURPA policies, and Falls Creek would receive very different prices and could potentially operate and sell power to PacifiCorp, if it happened to be located in another state. For example, in Idaho, Falls Creek could receive capacity payments during the sufficiency period because it has been selling power to

PacifiCorp for over thirty years. Idaho does not eliminate capacity payments for existing QFs simply because their current contract expires and they enter into a new contract. Washington similarly pays QFs for capacity during all contract years, unlike Oregon which does not pay QFs for capacity during the "sufficiency period", which is currently nearly all contract years. Other states also allow levelized prices, which allows QFs to operate during periods of low resource sufficiency period prices. We do not understand why Oregon's PURPA policies are so hostile to existing and operating QFs like Falls Creek.

II. PARTIES' POSITIONS

Q Please summarize PacifiCorp's requests in this case.

A PacifiCorp has already successfully convinced the Commission to place into effect avoided cost rates that assume PacifiCorp has no need to acquire a major renewable or non-renewable resource until 2028. The currently effective rates also rely on the assumption that by 2028 PacifiCorp will have no incremental transmission costs to deliver energy from a wind farm located in Wyoming, and therefore the high-capacity factor Wyoming wind farm is the avoided renewable resource in 2028. The Commission approved these extremely low rates after the public meeting on August 26, 2016, as memorialized in Order No. 16-307, and those rates remain in effect today.

Now, PacifiCorp proposes to lower the rates even further through the testimony of its witness, Brian Dickman. Mr. Dickman's testimony again asserts that PacifiCorp will not acquire another renewable or non-renewable resource until 2028. He argues it is reasonable to assume that PacifiCorp will wait to acquire a new physical renewable resource until the very last date that its current bank of renewable energy certificates ("REC") allows it to meet the RPS, which is 2028.[1] But he goes a step further to assert that the performance and cost assumptions for the renewable resource from the 2015 IRP are too high, and proposes to lower the costs and increase the performance of the Wyoming wind farm, consistent with PacifiCorp's cost and performance assumptions in its unacknowledged 2015 IRP Update.

Q Please summarize your request in this proceeding.

A The Commission should adopt new avoided cost rates, including a renewable resource sufficiency/deficiency demarcation of sometime between 2019 and 2022, a non-renewable resource sufficiency deficiency demarcation of 2021, and the costs of renewable resources should not be changed until the Coalition and CREA are able to review evidence that would allow us to determine if PacifiCorp's 2015 IRP Update prices are reasonable. We think PacifiCorp's actual statements in numerous other proceedings support earlier resource acquisitions. In nearly every administrative forum and actual action, other than avoided cost proceedings in which the Company wants to push out the deficiency demarcation, PacifiCorp has made it clear that it intends to acquire renewable resources more quickly than 2028. For example:

- PacifiCorp's statements before the Commission and the legislature that SB 1547 "provides an opportunity to procure over 600 MW of low-cost renewable resources over the near term" and explaining that unlimited

[1] PAC/100, Dickman/8.

REC life and federal production tax credits make renewables about 30% less costly while those credits are in full effect.[2]

- PacifiCorp's statements in its updated 2017-2021 RPIP that PacifiCorp would not wait until 2024 to make its next resource acquisition, and would "continue to monitor the market to assess the optimal time for additional acquisitions for RPS compliance" instead.[3]

- PacifiCorp's statements to the Commission that PacifiCorp would issue additional Renewable RFPs in the near future and "pursue bi-lateral renewable resource opportunities if cost effective for customers."[4]

- PacifiCorp's statements in its 2017 IRP that PacifiCorp plans to build 1,100 MW of new wind projects, primarily in Wyoming, by the end of 2020, add another 859 MW of new wind capacity – 85 megawatts in Wyoming and 774 MW in Idaho – between 2028 and 2036, and build 1,040 MW of new solar capacity between 2028 and 2036.

- PacifiCorp's decision to immediately pursue resource acquisitions prior to the completion of its 2017 IRP, including the statement that the PacifiCorp's 2017 Renewable RFP "will seek up to 1,270 MW of wind resources that can achieve a commercial operation date of no later than December 31, 2020".[5]

Q Please summarize your testimony.

A We will address several of the recent changes that have occurred since acknowledgment of the 2015 IRP, which make the assumptions underlying PacifiCorp's proposal unreasonable. Those changes since acknowledgment of the

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[2] OPUC Special Public Meeting, Oregon Clean Electricity & Coal Transition, PacifiCorp Presentation at 2 (Jan. 29, 2016); HB 4036 Public Hearing, House Committee On Energy and Environment, PacifiCorp Testimony of Scott Bolton at 57:50 (Feb. 4, 2016).

[3] Re PacifiCorp RPIP, Docket No. UM 1790, PacifiCorp's Reply Comments at 5 (Oct. 28, 2016) (internal citations omitted).

[4] OPUC Special Public Meeting, PacifiCorp Presentation to the Commission regarding ongoing renewable and REC RFP process with the potential of an executive session at 3 (July 26, 2016); Re PacifiCorp, dba Pacific Power, 2015 IRP, Docket No. LC 62, 2015 IRP Update at 56 ("To fully evaluate Oregon RPS compliance alternatives that consider potential near-term, time- sensitive resource procurement opportunities, PacifiCorp intends to issue requests for proposals (RFPs) seeking both REC purchase and resource procurement alternatives.").

[5] http://www.pacificorp.com/sup/rfps/2017-rfp.html

2015 IRP include: 1) the enactment of Senate Bill ("SB") 1547; 2) PacifiCorp's announcement of closure of two of its coal plants; 3) increased clarity surrounding Clean Air Act regulations (Regional Haze rules in Utah) that will result in accelerated retirement of additional coal plants; and 4) PacifiCorp's actual plans to monitor the market to assess the optimal time for additional acquisitions for RPS compliance in the near term, as illustrated by its 2016 Renewable Request for Proposals ("2016 Renewable RFP") and 2017 IRP that calls for 1,100 MW of renewables by 2021. The only place in which PacifiCorp has claimed that it is not planning to acquire renewable resources is in its avoided cost rate case, which puts significantly into question the integrity of the Commission's avoided cost rates process. Based on these events, the Commission should conclude that PacifiCorp's actual, as well as least-cost, plan to comply with SB 1547 and coal plant regulations do not allow it to wait until 2028 to acquire the next major renewable and non-renewable resources.

With regard to resource costs and performance criteria, PacifiCorp did not provide us with requested discovery that would enable us to agree that the assumptions in the 2015 IRP Update are reasonable for purposes of setting the avoided costs. It is our understanding that renewable resource costs have declined since the 2015 IRP was acknowledged; however, PacifiCorp has not demonstrated that its proposed costs are reasonable in their totality.

PacifiCorp has suggested that its multi-year IRP process thoroughly vets all of the data presented in the IRP, which is incorrect because long-term sufficiency periods are not included in the action plan and are therefore not acknowledged by the Commission. Because the five-year action plan receives a more robust review, it is inaccurate to suggest that long-term sufficiency periods receive the same detailed analysis as the data within the action plan. Again, basing avoided cost prices on a resource sufficiency/deficiency demarcation outside an IRP's action plan creates doubt as to the fairness of the establishment of the resulting avoided cost prices.

The Commission's assumption that PacifiCorp's sufficiency demarcation correlates with its existing renewable energy credit bank is misguided because it assumes that PacifiCorp might wait until the very year it is facing non-compliance to acquire new resources. In reality, PacifiCorp has historically stayed well ahead of the compliance curve, and this trend should be considered by the Commission. While many might claim that avoided cost prices are always too high, a counter observation is that utilities have for a very long time typically acquired resources in advance of the time-frames proposed in previously acknowledged IRPs.

Finally, the Commission should use common sense when reviewing the various issues in this proceeding. PacifiCorp's approach in avoided cost proceedings has been to push out the date of deficiency for more than a decade. This has worked, as the Company's rates reflect this inaccurate assumption that the Company has no plans to acquire new resources. This means that QFs have been effectively barred from selling their net output to PacifiCorp, because rates are too low. This has put a halt to new development and risks shutting down existing QFs. PacifiCorp, however, has been saying in every other area (before the legislature, in its IRP, in the renewable portfolio standard implementation plans, etc.) that it will acquire new renewable resources soon. Even more important, PacifiCorp has been taking steps to acquire new renewable resources.

Even if the Commission agrees with the Coalition and CREA that avoided cost rates should be adjusted, this may be a short term victory. If and when PacifiCorp acquires new renewable resources, we can all expect PacifiCorp to come before the Commission and propose again to move its resource deficiency period out. QFs are caught in a never ending cycle of low avoided cost rates. While the next avoided cost rate case is outside of the scope of this proceeding, the Coaliton and CREA believe that PacifiCorp should be found to be in a permanent state of renewable resource deficiency, at least until the Company can demonstrate that it definitively will not take any actions to acquire new resources.

In summary, PacifiCorp has not been waiting, nor would it be reasonable to wait, until 2028 to acquire its own new generation resources, especially renewable resources. Since PacifiCorp is likely to acquire renewable generation before 2028, PacifiCorp's avoided cost rates should be set so that it also acquires QF resources prior to 2028 If the Commission allows PacifiCorp continue to use the 2028 dates for the purposes of setting avoided cost rates, then avoided cost rates will not be based on the incremental costs to PacifiCorp of electric energy and capacity which, but for the purchase from Oregon QFs, PacifiCorp would generate itself or purchase from another source.

III. WHY THIS MATTERS

Q Are any Oregon policy goals impacted by PacifiCorp's filing?

A Yes. There are a number of regulatory requirements and proposals that support maintaining existing and encouraging new QF development, including responding to the Environmental Protection Agency's ("EPA") existing coal plant regulations, Oregon's goals to reduce greenhouse gas emissions, and Oregon's requirement that by 2025 at least eight percent of Oregon's investor-owned utilities generating capacity comes from "small-scale renewable energy projects with a generating capacity of 20 megawatts ("MW") or less".[6] It will be extremely difficult, if not impossible, to meet the eight percent requirement without PURPA policies that allow existing QFs to continue to operate and new projects to be developed. In addition, it is likely that some existing projects with expiring contracts will be unable to continue to sell to PacifiCorp under the current rates that include no compensation for capacity.

Q What will be the impact on new QF development from these rates?

A With the extremely low rates being offered by PacifiCorp, it is difficult to imagine new projects entering into long-term contracts because they will not be economically possible. After the Commission revitalized its implementation of PURPA in 2005 in docket UM 1129, there has been a modest level of new development of small QF projects. Additionally, the Commission's policy to offer renewable-based rates established in Order No. 11-505 has provided moderate opportunities and continued development even in the face of record-low

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[6] ORS 469A.210.

wholesale energy and gas prices. The renewable avoided cost rate option also helps PacifiCorp meet its RPS requirements by committing to supply RPS attributes and energy. These policies have been positive steps for small Oregon generators, but the current rates completely undermine these policies by pushing the deficiency dates unreasonably far into the future.

Q You mentioned existing QFs. What are they and why are they different?

A Existing QFs are those projects that are already operating and are generally selling power to the interconnected utility. Some of these projects have been operating since the mid 1980s.

Existing QFs face a number of unique challenges, including the fact that they cannot wait to sign their next contract until a time when market prices may improve. The existing QF's contract will expire on a set date, and if a replacement contract is not in place by that time the QF cannot sell its output.

Even though the utilities have relied upon the capacity value of existing QFs for years in the resource portfolio for planning purposes, these QFs will suddenly stop receiving capacity payments during the sufficiency period when they renew their contracts. A new QF developer may wait out a period of low resource sufficiency period prices by selecting a later on line date (up to three years), or waiting to sign a contract and develop their project until prices improve. Existing QFs, in contrast, have a fixed date for contract expiration and must either sign up for the new prices or stop operating. While existing QFs can also sign contracts years in advance of contract expiration, they cannot control when their contract expires, which places them at a huge risk of market fluctuations.

This situation is similar to someone planning to retire who must take all of their money out of the retirement account at a specific date, regardless of whether there is a stock market crash or not. In terms of avoided cost prices, we are in an unprecedented market collapse. There are numerous economically reasonable tools that this state has implemented in the past (and other states implement currently) to offset this problem, including levelized rates and paying existing QFs capacity payments in the sufficiency period. But this Commission has repeatedly rejected these efforts. As a result, QFs will be forced to close their Oregon operations, when they may otherwise be able to operate if located in Idaho or Washington simply because of more favorable treatment to existing QFs.

Q Are you recommending changes to the sufficiency period policies that provide no compensation to any QFs for avoided capacity until the utility's projected acquisition of the next major renewable and non-renewable resource?

A No. We understand that methodological changes are outside the scope of this proceeding. However, the Commission should recognize the impact of allowing the utilities to pay extremely low energy-only, market-based prices during the sufficiency period and should be vigilant to require that the utilities, including PacifiCorp, do not "game the system" by stretching the sufficiency period out longer than is reasonable. It is common knowledge that PacifiCorp has in inherent disincentive to purchase power from QFs, and the easiest way to limit its PURPA obligation in Oregon is to arbitrarily stretch out the sufficiency period. A reasonable sufficiency period policy should send proper economic signals to QFs, not act as an arbitrary economic barrier to QFs development. Payment for capacity and/or levelization of prices are very fair and reasonable ways to mitigate the damage created by inaccurate and overly extensive resource sufffciency periods.

IV. PROBLEMS WITH THE SUFFICIENCY PERIOD DETERMINATIONS FROM PACIFICORP'S 2015 IRP

Q How does the Commission usually determine the appropriate sufficiency period?

A In Order No. 10-488, at page 3, the Commission explained the sufficiency and deficiency periods as follows:

For both two-year and post-IRP filings, the start date of the first "major resource acquisition" in the action plan of the most recent acknowledged IRP demarcates the resource "sufficiency" and "deficiency" periods.

- A "major resource" is defined as it is in the competitive bidding rules, which is a generation resource of 100 MW or greater and five years or longer. For two-year filings, the utility may seek acknowledgement of an updated action plan.
- Renewable resource acquisitions may be major resource acquisitions for purposes of determining the avoided costs for a renewable resource QF eligible under the RPS.
- For partially acknowledged plans or acknowledged plans with a range of on-line years for the next major resource acquisition, the Commission will indicate how the utility shall determine avoided costs.

The Commission's process for setting resource sufficiency and deficiency periods was based on the expectation that the sufficiency period would be no longer than five years after IRP acknowledgement because it looks to next major resource being within the utility's "action plan," which is the five-year plan. Prior to Order No. 10-488, the sufficiency periods were almost always five years or less.

In any event, these dates are the starting point for any avoided cost rate filing, and can be reviewed and challenged based on their reasonableness. The utility's IRP is not a contested case and does not allow the stakeholders an opportunity to obtain a Commission order on the reasonableness of most of the avoided cost rate inputs and assumptions. Therefore, now is the time for such a challenge.

Q How did the Commission determine PacifiCorp's current sufficiency periods?

A PacifiCorp first proposed that there was no renewable deficiency period, despite the fact that it was actually planning on issuing its 2016 Renewable RFP. During the Public Meeting on August 26, 2016, the Commissioners first acknowledged that the sufficiency period requires a detailed, and factually intensive determination that is not well-suited for determination at a public meeting. The Commission determined both the renewable and non-renewable sufficiency periods for PacifiCorp, but as what it described as "interim rates" based on a 2028 sufficiency period for both renewable and non-renewable resources. The Commission recognized that the rates would be subject to review, due to the lack of credible evidence to support either date. For example, Commissioner Savage described 2028 as the first "known" date for PacifiCorp's renewable deficiency, simply because PacifiCorp had testified in another proceeding that its current REC bank could keep it RPS compliant until 2028.[7]

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[7] Regular Public Meeting at 48-52 (Aug. 16, 2016).

The improvised approach to determine the sufficiency periods correctly began by rejecting PacifiCorp's outdated proposal, and was based on an attempt at ascertaining a more accurate date. However, the 2028 dates are flawed because they ignore several key facts that have occurred since PacifiCorp concluded its 2015 IRP process. For example, that PacifiCorp is actively looking to acquire new resources. The 2028 dates also assume that PacifiCorp will wait until it faces RPS non-compliance to make a new acquisition, which is an unrealistic assumption that has never occurred in the past.

Q Does the Commission normally acknowledge the sufficiency/deficiency demarcation date?

A Yes, at least historically it did. In past IRPs, the sufficiency period would fall within the five year action period and was therefore specifically acknowledged by the Commission in the IRP acknowledgement. However, by pushing the sufficiency date out beyond the action plan (or even beyond the full twenty-year review period), the sufficiency demarcation does not benefit from the more robust review that the action plan receives, and is therefore not technically acknowledged. As Commissioner Savage recently noted, "once it is out of the action plan, it is not really acknowledged."[8]

Q Did the Commission acknowledge PacifiCorp's current sufficiency periods?

A No. PacifiCorp's 2015 IRP, which was acknowledged, does not include a sufficiency/deficiency demarcation for either renewable or non-renewable generation within the planning horizon. The acknowledged IRP identified 2028 as its next acquisition date for non-renewable and beyond 2040 for renewable

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[8] Regular Public Meeting (Aug. 16, 2016)

resources. PacifiCorp did not seek acknowledgment of its subsequent IRP filing, the 2015 IRP update. The Commission did not conduct any substantive review of these specific dates, and they should be provided no weight in terms of their accuracy or reasonableness.

Q Have there been any significant changes to the regulatory environment in recent years that affect the Commission's sufficiency period analysis?

A Yes. The regulatory environment has changed significantly in recent years. The traditional notion of regulated utilities was to build resources when they were needed in a purely electrical sense to meet growing loads, but in today's environment a regulated utility must also plan within the complex regulatory compliance framework where prudent utilities are looking at the least-cost way to transition away from carbon-intensive asset bases.

In this context, a fair analysis of PacifiCorp's next resource acquisition is driven by the newly enacted requirements of SB 1547 and Clean Air Act regulations that will result in accelerated retirement of additional coal plants, as much as it is by traditional drivers like load growth. Those two major regulatory factors have changed and support earlier renewable and non-renewable resource acquisitions since the acknowledgement of PacifiCorp's 2015 IRP, as Dr. Fisher points out in his testimony. The Commission must be sure that the utility is planning its need for regulatory compliance.

Q Was the regulatory environment a significant factor in determining PacifiCorp's current sufficiency periods?

A Yes. At least it should have been. The 2015 IRP maintained that incremental REC purchases would be sufficient to permit PacifiCorp to remain RPS compliant throughout the twenty-year horizon evaluated and that repowering coal plants would allow it to avoid a new major resource acquisition. However, additional analysis is warranted.

Q Have you noticed any changes in PacifiCorp's resource acquisitions in recent years that likewise affects the Commission's sufficiency period analysis?

A Yes. The nexus between PacifiCorp's IRP and the competitive bidding, RFP process seems off. The IRP is supposed to predict when the company will acquire its next major resource, which should trigger an RFP process that follows the Commission's competitive bidding guidelines. Yet the Company's practice of late has been to unexpectedly acquire or seek to acquire resources that are not announced in the IRP, which extends the sufficiency period back and lowers avoided cost rates.

Because avoided cost rate are based upon when the date that PacifiCorp officially plans to acquire a major resource, as indicated in its last-acknowledged IRP, the IRP date may not accurately reflect PacifiCorp's actual plans. In other words, these unexpected acquisitions allow PacifiCorp to manipulate its avoided cost prices. It appears that through "unexpected" acquisitions, utilities could ensure that avoided cost prices are never able to catch up and are always kept artificially low. This is exacerbated because, once the utility makes its "unexpected" acquisition, then the utility no longer needs new resources, which again extends the date of resource acquisition used to set avoided cost rates.

V. RENEWABLE RESOURCE SUFFICIENCY PERIOD PROBLEMS

Q Please describe PacifiCorp's proposed renewable resource sufficiency-deficiency period.

A PacifiCorp's 2015 IRP proposed a sufficiency period that extended essentially forever, beyond the entire 20-year planning horizon, for renewable resources. PacifiCorp maintained that these sufficiency periods were reasonable even after the enactment of SB 1547, which increases Oregon RPS to 50 percent by 2040 and bars imported coal energy for use in the state. After the Commission rejected this approach, PacifiCorp has revised its position a number of times, finally arriving at its current proposal that it will not acquire another major renewable resource or non-renewable resource until 2028.

Q Do you agree with PacifiCorp that they will not acquire a new renewable resource until 2028?

A No. First, Dr. Fisher has investigated the technical analysis of PacifiCorp's least-cost path to achieve regulatory compliance and has concluded that, if PacifiCorp were acting prudently based on information available today, it would acquire its next RPS-compliant major renewable resource between 2018 and 2022. Second, there are several non-technical indicators pointing to the likelihood that PacifiCorp will in fact acquire a renewable resource sooner than 2028, notwithstanding its position in this case. These include: 1) PacifiCorp's actual plans are to acquire renewable resources more quickly than 2024 (note that the current sufficiency period in PacifiCorp's renewable avoided costs is 2028—not even 2024); 2) PacifiCorp historic trend of acquiring renewable resources far in advance of need; and 3) PacifiCorp's repeated public statements that it will acquire renewable resources in the near term.

Q What are those high-level indicators that PacifiCorp will need a renewable resource prior to 2028?

A PacifiCorp relies on 2028 as the renewable deficiency date because that is the date its existing REC bank will expire. In other words, that is the date on which it would begin to incur significant penalties if it does not acquire a renewable resource sooner. However, it is not reasonable to expect that PacifiCorp will wait until the company is going to incur penalties to acquire the next major renewable resource, because PacifiCorp has consistently built major renewable resources way in advance of that point. Even if one were to accept PacifiCorp's economic analysis (instead of Dr. Fisher's), it is very likely PacifiCorp would again acquire a major renewable resource in advance of the expiration its existing REC bank. In that event, QFs would be arbitrarily deterred from being developed, and Oregon would be deprived of cost-effective QF resources.

Q Mr. Dickman suggests that PacifiCorp will simply acquire RECs to meet its RPS compliance requirements even under SB 1547. How do you respond?

A PacifiCorp's proposal to pursue a predominantly REC-based strategy could pose more risks than a "physical compliance" strategy, and fails to take advantage of early action incentives that could offer ratepayers significant potential savings and other benefits. The REC-based strategy is risky, based on current resource costs, regulatory conditions, and expiring tax credits. PacifiCorp's RFP results suggest that this pressure is already being applied, as one of the winning bidders from its REC RFP subsequently withdrew its bid to supply RECs from six projects.[9]

Additionally, PacifiCorp's own analysis suggests that near-term acquisition of a physical resource is the least-cost path forward in this regulatory environment. In its July 15, 2016 RPS Plan Application, the Company found that "near-term procurement can lower RPS compliance costs over the long-term".[10]

Finally, we note that we are not recommending that PacifiCorp's renewable resource sufficiency date be moved up to 2017 or even 2018. We are recommending a date in the range of 2019 to 2021, which is far more reasonable than PacifiCorp's proposed 2028 date.

Q Has PacifiCorp stated that despite its long resource sufficiency period, it actually intends to acquire renewable resources more quickly, perhaps through "unexpected" acquisitions?

A Yes. PacifiCorp made this point in its Reply Comments on PacifiCorp's Updated 2017-2021 Renewable Portfolio Implementation Plane ("RPIP). PacifiCorp clearly stated:

> **Sierra Club claims that the Company is choosing to 'preferentially wait until 2024 to acquire new resources rather than harness low cost resources today.' This statement is simply not true. PacifiCorp has clearly indicated that it will continue to monitor the market to assess the optimal time for additional acquisitions for RPS compliance.** Sierra Club apparently conflated PacifiCorp's current analysis of renewable resource price trajectories—which indicated renewable resource

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9 PacifiCorp, 2017 Integrated Resource Plan, Public Input Meeting 3, Aug. 24-26, 2016, Slide 110, available at: www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_2017_IRP_PIM03_8-25-2016_to_8-26-2016.pdf.

10 Re PacifiCorp RPIP, Docket No. UM 1790, July 15, 2016 Application, Table A-18, Appendix A, page 20.

> prices will likely be lower post-2024—with a refusal to acquire resources before 2024. This assumption finds no factual basis in either the Updated 2017-2021 RPIP, the document that is actually at issue in this proceeding, or the Company's public documentation of its RFP process, which is not at issue in this proceeding.[11]

If PacifiCorp is to be taken at its own word, then it appears that PacifiCorp will not be waiting until 2024 (when prices are expected to decrease) let alone until 2028 (when it faces resource penalties).

Q Is there any other evidence in the public realm of PacifiCorp's likely actions?

A Yes. During the last legislative session, PacifiCorp informed the Legislature that the Oregon renewable portfolio standard revisions "incents early action through its REC banking provision, which allows utilities and customers to benefit from recently extended federal tax credits. HB 4036 enables at least 225 MW of additional low-cost renewable procurement over the near-term."[12] Similarly, PacifiCorp informed the Commission at its January 29, 2016 hearing regarding the RPS revisions that the bill would provide PacifiCorp "an opportunity to procure over 600 MW of low-cost renewable resources over the near-term." PacifiCorp then immediately proceeded with an RFP focused on obtaining utility owned generation resources. While PacifiCorp's 2016 RFP did not result in new resources, PacifiCorp has explicitly stated that it will issue additional Renewable RFPs in the near future and "pursue bi-lateral renewable resource opportunities if

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11 Re PacifiCorp RPIP, Docket No. UM 1790, PacifiCorp's Reply Comments at 5 (Oct. 28, 2016) (internal citations omitted) (emphasis added).

12 Hearing Before the House Committee on Energy and Environment, 78th Oregon Legislative Assembly-2016 Regular Session, Scott Bolton presentation at 2 (Feb. 2, 2016). SB 1547 was originally HB 4036.

cost effective for customers."[13] Now, PacifiCorp has proposed in its IRP to acquire over 1,000 MWs in new renewable RFPs by 2021. It is hard to take PacifiCorp seriously when it claims in this PURPA proceeding that it will not acquire a new renewable resource until 2028. The only time PacifiCorp claims it is not planning on acquriing renewable resources is when it is time to set rates for QF projects.

Q Historically, has PacifiCorp *ever* waited until immediately before facing penalties before meeting its RPS requirements?

A No. PacifiCorp's historic trend has never been to wait until it faced non-compliance to acquire new generation resources. For example, under Oregon's original RPS mandate, PacifiCorp needed 5% of its annual load to come from qualifying renewable resources by 2011, and as of 2010 it was already allocating twice that many bundled RECs to Oregon.[14] In 2015 PacifiCorp's renewable portfolio standard requirements raised to 15%, and PacifiCorp met these requirements with generation from qualifying renewable resources equal to 10% of its load and RECs that equaled 5% of its load.[15] This means that by 2015, PacifiCorp had amassed a very large REC bank, and was able to start to draw

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13 OPUC Special Public Meeting, PacifiCorp Presentation to the Commission regarding ongoing renewable and REC RFP process with the potential of an executive session at 3 (July 26, 2016); Re PacifiCorp, dba Pacific Power, 2015 IRP, Docket No. LC 62, 2015 IRP Update at 56 ("To fully evaluate Oregon RPS compliance alternatives that consider potential near-term, time-sensitive resource procurement opportunities, PacifiCorp intends to issue requests for proposals (RFPs) seeking both REC purchase and resource procurement alternatives.").

14 Oregon's retail load in 2010 was 12, 717,170 MWh and Oregon's REC share that same year was 1,247,291, which is 10.2%. These numbers do not include ETO transfers and are therefore conservative estimates.

15 Oregon's retail load in 2015 was 12,862,461 MWh and Oregon's REC share was 1,33,863, 9.6%.

down that bank.[16] As of 2016, and after SB 1547 raised future RPS requirements, PacifiCorp's IRP stated that it had banked enough RECs to keep it complaint through 2028. Despite building a REC bank to support more than a decade of compliance, PacifiCorp issued an RFP in 2016 to ascertain whether an immediate renewable resource acquisition was prudent.

PacifiCorp's historic trend for meetings RPS obligations well beyond its requirements appears to mirror PGE's approach. In PGE's 2009 IRP, PGE proposed resource acquisition in 2012 to achieve compliance with its 2015 RPS obligation, explaining that banking RECs "from early renewable resource actions provides a significant cushion for meeting RPS compliance"[17] PGE repeated this same strategy in its 2016 IRP and described its need to preserve "a minimum REC bank" sufficient to cover one to two years' of event risk.[18]

Q Can you think of any other reasons that a prudent utility would not wait until 2028 to acquire a major renewable resource for purposes of complying with SB 1547?

A In light of SB 1547's increased RPS requirements and the extension of the federal production tax credit ("PTC") and investment tax credit ("ITC"), early action on procurement of physical renewable resources before 2028 is the obvious path forward for PacifiCorp, if it were to act prudently. PacifiCorp has the opportunity to acquire "golden" RECs—which have an unlimited bankable life—through procurement of new, long-term renewable energy projects that come online prior

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16 After SB 1547, PacifiCorp still needed 25% in 2025, but additionally needed 35% in 2030, 45% by 2035 and 50% by 2040.

17 2009 Staff Report (citing PGE's 2009 IRP at 114).

18 PGE's "event risk" appears to be loosely tied to its RPS obligation. PGE's 2016 IRP at 292-93.

to 2023. The first five years of generation from these projects will produce golden RECs.[19] In contrast, RECs generated from post-2023 projects (like PacifiCorp's proposed 2028 wind farm in Wyoming) may only generally be banked for five years.

Additionally, expiring tax credits also strongly incent development in the near term. Wind under construction, or turbine equipment safe harbored, by the end of 2016 is eligible for 100% of the PTC, which is a tax credit for each kilowatt hour of produced energy for the first 10 years of operation of qualifying projects. For wind projects that do not begin construction or otherwise achieve "safe harbor" status by the end of 2016, the PTC decreases to 80% of its full value for beginning construction in 2017, and eventually comes to an end at 40% for projects beginning construction in 2019. The ITC, which is a tax credit of 30% of the initial investment in the facility and is often used for solar energy projects, stays at 30% for projects that begin construction through the end of 2019 and then begins to ramp down. The opportunity to capture the full benefits of the PTC and ITC in the near term offers significant potential savings for PacifiCorp ratepayers.

VI. NON-RENEWABLE RESOURCE SUFFICIENCY PERIOD PROBLEMS

Q Please describe PacifiCorp's proposed non-renewable resource sufficiency-deficiency period.

A PacifiCorp's 2015 IRP proposed a sufficiency period extended to 2028 for non-renewable resources.

[19] ORS 469A.140(3).

Q How did PacifiCorp's 2015 IRP determine a 2028 deficiency date for non-renewable resources?

A The 2028 date reflects PacifiCorp's plan to retire an entire coal plant (Dave Johnston) without a known replacement. PacifiCorp did not consider its earlier plans to retire two other coal plants (Naughton 3 and Cholla 4) as major resource acquisition, because according to the 2015 IRP, PacifiCorp planned to repower them as natural gas plants.

Q Why did the Commission select 2028 as PacifiCorp's non-renewable sufficiency date?

A At the August 16, 2016 public meeting, the Commissioners explained that the 2028 date reflects PacifiCorp's first planned major resource acquisition, according to its most recently acknowledged IRP. Due to the lack of evidence supporting either 2028 or another date, the Commission relied upon "procedural clarity" to guide its decision.

Q But, did the Commission actually acknowledge PacifiCorp's 2028 non-renewable sufficiency period?

A No. The Commission acknowledged PacifiCorp's 2015 IRP action plan, which was limited to actions within two to four years. Thus, because PacifiCorp's proposed 2028 sufficiency period was not part of the 2015 IRP's action plan, it was not subjected to the more vigorous action-plan review and was not acknowledged by the Commission.

Q Do you agree with PacifiCorp that they will not acquire a new major non-renewable resource until 2028?

A No. During PacifiCorp's 2015 IRP, QF parties argued that PacifiCorp relied too heavily upon front-office transactions and failed to take into account impending environmental regulation that would necessitate economic coal plant retirements.

PacifiCorp refused to consider economic or endogenous coal plant retirements and instead selected as its preferred portfolio one that ignored the QFs arguments.

Q Has anything changed since PacifiCorp's 2015 IRP that would affect the analysis for non-renewable resource acquisition?

A Yes. First, additional pollution control rules have been put in place under EPA's Regional Haze regulations (we note that these requirements are different from the Clean Power Plan that the Trump administration is planning to abandon). Second, PacifiCorp changed its plans after the 2015 IRP was acknowledged and announced additional coal plant closures of Naughton 3 and Cholla 4. Third, PacifiCorp filed an IPR Update addressing the increased RPS requirements of SB 1547, which it did not seek acknowledgement of, and issued two RFPs for new renewable resources. PacifiCorp has not analyzed how any of these changes would affect its non-renewable sufficiency period. Thus, the assumptions made by PacifiCorp with respect to future coal-plant closures are no longer reasonable.

Q Did PacifiCorp's 2015 IRP Regional Haze Scenarios, raise concerns?

A Yes. Originally, PacifiCorp's IRP had two Regional Haze Scenarios that contemplated shutting down at least one Dave Johnston unit by 2019. Near the end of the IRP process, PacifiCorp added a third Regional Haze Scenario that had no retirements until 2028. The new portfolio was ultimately selected as the preferred portfolio, without providing stakeholders an opportunity to vet the alternative retirement assumptions.

VII. RENEWABLE RESOURCE COST INPUTS

Q Please describe PacifiCorp's proposed renewable resource cost inputs.

A PacifiCorp proposes to use the renewable resource costs from its 2015 IRP Update.

Q Do the Coalition and CREA support use of the 2015 IRP Update costs?

A No. While the Coalition and CREA agreed that renewable resource costs have declined since PacifiCorp's 2015 IRP was acknowledged, our understanding is that these costs are outside the scope of the proceeding. The ALJ ruled that in opening a more thorough vetting of PacifiCorp's avoided costs, "we did not support the use of an unacknowledged IRP Update as the source for avoided resource characteristics and costs."[20]

Q Did the Coalition and CREA seek to verify the reasonableness of PacifiCorp's 2015 IRP Update costs?

A Yes. The Coalition and CREA sought to review whether PacifiCorp's costs estimates were accurate based on more current information, including bids submitted into the Company's 2016 Renewable RFP, internal memoranda to PacifiCorp decision-makers regarding the decision not acquire a resource in the RFP, and documents provided to parties in other related proceedings. The Commission denied a request to compel information regarding this Renewable RFP information.[21] If those requests had been granted, then the Coalition and CREA might have been able to discover that PacifiCorp was actually planning on

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[20] Re PacifiCorp, dba Pacific Power Investigation into Schedule 37 – Avoided Cost Purchases from QFs of 10,000 kW or less, Docket No. UM 1794, Order 17-121 at 5 (March 23, 2017).

[21] Id.

issuing RFPs for huge amounts of renewable power, which would have undermined its claims in this case.

Q What information did the Commission direct the Coalition and REC to use to review the reasonableness of PacifiCorp's avoided cost rates?

A While not limited to only one data request, the Commission specifically referred to CREA's data request 1.9, which sought information regarding PacifiCorp's 2015 IRP. Thus, the Commission has prevented the Coalition and CREA from reviewing information more contemporaneous with the 2015 IRP Update, but allowed the Coalition and CREA the ability to review information regarding the 2015 IRP, the only legally defensible outcome is that the Commission must reject PacifiCorp's 2015 IRP Update costs and assumptions and instead use the 2015 IRP, as acknowledged by the Commission.

Q Is there other evidence that PacifiCorp's overall proposed renewable costs are not reasonable?

A PacifiCorp wishes to use lower renewable costs from its IRP Update, but does not want to include the significant transmission costs to wheel that power to Oregon. PacifiCorp has proposed to begin construction "on a segment of the Gateway West 500-kilovolt transmission line between Medicine Bow, Wyoming, and the Jim Bridger power plant."[22] The Company states that the "140-mile line, set to be in service by the end of 2020, would enable additional wind generation and improve the operational efficiency of the broader system by relieving transmission congestion in Wyoming."[23] If the Commission adopts PacifiCorp's

[22] https://www.pacificpower.net/about/nr/nr2017/pp-irp-clean-energy-investments.html
[23] Id.

lower renewable costs, then the cost of transmission associated with those resources should be included in rates.

Q What is the Coalition and CREA's position on going forward basis?

A The Coalition and CREA believe that the Commission's order regarding the relevant scope of information that can be used to challenge avoided cost rates is fundamentally flawed and violates basic notions of fair and due process. The Coalition and CREA recommend that in future proceedings that QF parties be allowed to challenge the utility's avoided cost rate inputs and assumptions with more contemporaneous and relevant information, especially information within the utility's possession. The Coalition and CREA may be forced to challenge the Commission's unlawful decision to curtail our procedural rights in court subsequent to this proceeding, and reserves the right to challenge this policy in all appropriate forums in the future, including the Commission's upcoming avoided cost rate rulemaking. It is would be unfair for PacifiCorp to be able to select whatever inputs and assumptions it believes supports its case (i.e., the 2015 IRP Update), but to bar QF parties the ability to use other, even more relevant information, exclusively within PacifiCorp's possession (i.e., actual RFP bid results, internal memoranda to PacifiCorp decision-makers, documents provided in other related proceedings, etc.). Therefore, the Commission should rely upon the 2015 IRP because those were reasonable at the time the IRP was acknowledged.

VIII. CONCLUSION

Q Does this conclude your testimony?

A Yes.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1794

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER's	)
Investigation into Schedule 37 - Avoided	)
Cost Purchases from Qualifying Facilities	)
of 10,000 kW or Less.	)
	)
	)

RESPONSE TESTIMONY OF

JEREMY I. FISHER, PHD

ON BEHALF OF THE

RENEWABLE ENERGY COALITION

AND

COMMUNITY RENEWABLE ENERGY ASSOCIATION

May 30, 2017

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I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address, and position.

A My name is Jeremy Fisher. I am a Principal Associate with Synapse Energy Economics, Inc. ("Synapse"), which is located at 485 Massachusetts Avenue, Suite 2, in Cambridge, Massachusetts.

Q Please describe Synapse Energy Economics.

A Synapse Energy Economics is a research and consulting firm specializing in energy and environmental issues and policies for electricity sector issues, including fossil generation, efficiency, renewable energy, ratemaking and rate design, restructuring and market power issues, and environmental regulations.

Q Please summarize your work experience and educational background.

A I have worked in electricity system energy planning for a decade, evaluating and helping to shape resource plans, performing planning on behalf of states and municipalities, helping regulators navigate environmental rules, and assisting states craft or revise resource planning rules. I lead the resource planning group at Synapse, which engages in the assessment of planning processes across a wide cohort of states and regions.

I have provided consulting services for a wide variety of public sector and public interest clients, including the U.S. Environmental Protection Agency ("EPA"), the National Association of Regulatory Utility Commissioners, the National Association of State Utility Consumer Advocates, National Rural Electric Cooperative Association, the states of Alaska, Arkansas, Michigan, and Utah, the Commonwealth of Puerto Rico, Tennessee Valley Authority Office of

Inspector General, the California Division of Ratepayer Advocates, the California Energy Commission, the Regulatory Assistance Project, the Western Grid Group, the Union of Concerned Scientists, Sierra Club, Earthjustice, Natural Resources Defense Council, and other organizations.

I have provided testimony in electricity planning and general rate case dockets in Indiana, Louisiana, Kansas, Kentucky, Oklahoma, Oregon, Nevada, New Mexico, Utah, Washington, Wisconsin, and Wyoming.

I hold a doctorate in Geological Sciences from Brown University, and I received my bachelor degrees from University of Maryland in Geology and Geography.

My full curriculum vitae is attached as Exhibit REC-CREA/201.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Renewable Energy Coalition ("Coalition") and Community Renewable Energy Association ("CREA").

Q Have you testified in front of the Oregon Public Utility Commission previously?

A Yes. I first testified in before the Oregon Public Utility Commission ("OPUC" or the "Commission") in the Pacific Power (d.b.a. PacifiCorp, or Company) 2012 general rate case, commenting on PacifiCorp's planning process for investments in existing coal-fired power plants. I have been engaged in numerous technical conferences with the Commission and OPUC Staff ("Staff") on the Integrated Resource Plan ("IRP") process. In early 2015, I provided testimony on behalf of Sierra Club regarding the Company's application to approve the closure of the

Deer Creek mine in Utah and the acquisition of a long-term fuel agreement for Hunter and Huntington plants.

In addition to Oregon, I have testified on PacifiCorp resource planning matters before the Commissions of Utah, Washington, and Wyoming.

Q Have you previously testified on tariffs for qualified facilities?

A No, however the issues involved here are directly related to long-term resource planning conducted by PacifiCorp that subsequently inform the basis of the tariff.

Q Have you testified in other states on the appropriate treatment of resources in long-term planning processes?

A Yes. I have been involved in numerous long-term resource planning dockets, including on IRP, Certificate of Public Convenience and Necessity ("CPCN"), and prudence reviews in rate case dockets. I have provided training to federal regulators on resource planning practice and issues, and worked for the recently appointed Puerto Rico Energy Commission in an intensive review of the Commonwealth's first public resource plan in 2015.

Q What is the purpose of your testimony?

A My testimony assesses the dates of resource deficiency put forth by PacifiCorp in support of the August 24, 2016 Schedule 37 tariffs for qualified facilities ("QF"). I respond to the Company's justifications for these resource deficiency dates, discussed in direct testimony submitted on October 14, 2016.

I reviewed the mechanism that generated these resource deficiency dates, the underlying 2015 IRP assumptions, and new information since forthcoming, such as two relatively recent state and federal rules: (a) Oregon Senate Bill ("SB") 1547 which requires considerable new renewable resource procurement, and (b) the Environmental Protection Agency's Regional Haze Federal Implementation Plan for Utah, which requires new environmental control equipment at coal plants in Utah. Both of these requirements, as well as PacifiCorp's assessed reduction in renewable energy costs, result in substantial potential changes to the Company's long-term planning assumptions and subsequently impact resource deficiency dates.

Q What are your overall conclusions?

A The 2028 deficiency dates for non-renewable and renewable resources assessed by the Company in the Schedule 37 filing are not reasonable.

While I doubt whether the assumptions underlying the 2015 IRP preferred portfolio were ever reasonable, subsequent events have confirmed that the newly promulgated pollution control requirements under the Clean Air Act have rendered the coal plant closure assumptions in the 2015 IRP indefensible. This directly impacts the deficiency date for the next non-renewable resource by requiring the economic closure of PacifiCorp's coal plants sooner than assumed in the 2015 IRP. This closure necessitates acquisition of a replacement thermal resource sooner than 2028.

The enactment of SB 1547, release of the 2016 Resource and REC Request for Proposals ("RFP"), and recent release of the 2017 IRP have resulted in major changes since acknowledgment of the 2015 IRP. The analysis and data available in relation to those three events demonstrate that—under PacifiCorp's own resource cost assumptions—the most economic course forward for renewable portfolio standard ("RPS") compliance is to acquire physical renewable resources in the near term.

I conclude that the more reasonable assumption is that PacifiCorp has a non-renewable deficiency date of 2021 and a renewable deficiency date between 2018 and 2022.

Q What sources have you relied upon in your assessment of the non-renewable and renewable deficiency dates proposed by PacifiCorp in this docket?

A I reviewed the Company's application and Schedule 37 in this docket, the Company's filings and Commission orders in Docket UM 1729, the Company's 2015 IRP and 2015 IRP Update, the Company's Renewable Portfolio Standard Implementation Plan in Docket UM 1790, the results of the 2016 Resource and REC Request for Proposals presented before this Commission in July 2016, and the 2017 IRP released April 4, 2017.

In addition, I have deep familiarity with the Company's use of the System Optimizer ("SO") model for long-term resource planning. I have reviewed both input and output files from the SO modeling conducted by the Company in the 2015 IRP, and I have operated the SO model with the data from that proceeding. I believe that I have led the only non-PacifiCorp team to utilize the Company's SO modeling framework in a litigated proceeding in any PacifiCorp state.

Q Have you had access to all the information that you would otherwise require in this docket?

A No. This case asks, in part, parties to assess the deficiency dates for renewable and non-renewable resources for PacifiCorp. PacifiCorp's assessed deficiency dates are driven almost entirely by its use of the SO model in its IRP process. A fair and reasonable assessment of PacifiCorp's deficiency dates requires fairly extensive review of this model, as well as testing of assumptions excluded by PacifiCorp. Without the model, parties are compelled to rely on either circumstantial evidence or other runs conducted by PacifiCorp to theorize on potential likely outcomes. While this is standard procedure in cases where intervenors have limited access to information, it is far from ideal and creates an unwieldy task and high bar for intervenors. In particular, in a rate or tariff setting procedure, such as Schedule 37, an assessment of the SO model is key. Without such an assessment, the Company's monopoly on information is nearly absolute. Renewable Energy Coalition requested access to the SO model, or in absence of such access, to have PacifiCorp run models on its behalf. Important changes occurred from the time the 2015 IRP was conducted, as recognized by PacifiCorp in its 2015 IRP Update. And while Renewable Energy Coalition did not specifically seek to contest the Company's use of SO during the 2015 IRP, other parties did. The concerns raised by other parties during the 2015 IRP are manifest in this proceeding: As I will discuss, PacifiCorp's choice to eliminate endogenous coal retirement in the 2015 IRP and 2015 IRP Update, and now the 2017 IRP, biases the Company's resource deficiency dates and subsequently impinges on the parties in this case. The issues raised with respect to the SO model in the 2015 IRP were technical in nature and may not have been immediately apparent to participants other than PacifiCorp. While the Company has argued that the 2015 IRP was fully vetted and that Renewable Energy Coalition did not participate meaningfully, it was not apparent to most parties that PacifiCorp's analysis pathway would result in a largely pre-determined solution.

Therefore, for my analysis it would have been critical to assess the Company's SO model inputs and determine if the deficiency dates proposed by the Company—i.e., those apparently consistent with the 2015 IRP Update—were reasonable in nature.

Q Please summarize your findings regarding the insufficiency dates proposed by PacifiCorp for both thermal and renewable resources in this docket.

A The resource deficiency dates in Schedule 37 are based on flawed and outdated 2015 IRP input assumptions and mechanisms. The 2015 IRP predated the impacts of SB 1547, did not use an appropriate least cost / least risk framework, and did not appropriately account for EPA's regional haze rules.

The major resource acquisition dates, upon which Schedule 37's deficiency requirement is based, are a direct outcome of a non-optimized, subjective, and biased coal retirement framework constructed by PacifiCorp in the 2015 IRP. The Company's input assumptions for this coal retirement framework are – based on information known today – not consistent with environmental rules.

Because the preferred portfolio of the 2015 IRP is neither least cost nor consistent with environmental rules, the major acquisition dates, and thus the resource deficiency dates of Schedule 37, are invalid. It is unreasonable to base the resource deficiency dates of a tariff created in late 2016 on the outdated assumptions of the 2015 IRP.

Intervenors in this case asked PacifiCorp to run a new model run consistent with the rule of law today, and PacifiCorp declined to do so. Intervenors in this case asked PacifiCorp to provide a working copy of the model such that intervenors could create a model run consistent with the rule of law today, and PacifiCorp declined to do so.

In the absence of such a model run and based on my best estimates from the 2015 IRP and finalized rules from EPA under the Regional Haze Rule, I propose a non-renewable deficiency date of 2021. This date is consistent with the date upon which EPA requires substantial new environmental controls at the Hunter and Huntington coal-fired units, a factor not taken into account in PacifiCorp's 2015 IRP preferred portfolio.

PacifiCorp's proposed Schedule 37 is also inconsistent with the new regulatory requirements of SB 1547 and PacifiCorp's own evaluation of a least cost pathway to meet that regulation, consistent with assumptions in the 2015 IRP Update. PacifiCorp's own analysis of renewable resource procurement under that regulation, presented before this Commission in July 2016, indicated that the Company would preferentially acquire major renewable resources by 2018, assuming proxy renewable resource costs consistent with the 2015 IRP Update.

I recommend that:

1. The Commission require PacifiCorp to set current Schedule 37 rates with an assumed 2021 non-renewable deficiency date.
2. The Commission require PacifiCorp to set current Schedule 37 rates with a renewable deficiency date between 2018 and 2022.
3. The Commission require PacifiCorp to re-run System Optimizer with its currently assessed renewable proxy prices (i.e., 2015 IRP Update),

allowing the endogenous retirement of coal units and not restricting transmission as held by individual coal units.

4. The Commission should consider changing its criteria for IRP updates to reflect that resource procurement schedules can change as a function of gas and electricity prices, as well as other inputs used by the Company—not only commodity prices.

Q In the time since this case was opened, the Company has prepared and filed the 2017 IRP. Does the presence of the 2017 IRP change your opinion in any way?

A No. The bulk of this testimony was actually drafted in preparation for a December 2016 filing, well prior to the release of the new IRP. I have reviewed the 2017 IRP and my findings remain consistent, and are in fact reinforced by outcomes in the 2017 IRP.

Q In the time since this case was opened, a new federal administration has been formed. Does the election or the new administration change your opinion with respect to the Company's resource needs?

A No. While the new administration is notably less likely to promulgate new environmental rules impacting PacifiCorp's coal fleet, the implementation plans for the Regional Haze Rule – the major environmental rule driving near-term coal plant decisions – have been finalized by EPA in Utah and Wyoming. At this time, those rules are federally enforceable, or enforceable through citizen action, and represent a substantial requirement. Undoing these rules would require EPA to go through a lengthy rulemaking process, or directed US legislation. I assess that the most appropriate action is to plan on the rule of law, and the assumption that these finalized rules will move forward on schedule.

II. RESOURCE DEFICIENCY DATES ARE A DIRECT OUTCOME OF PACIFICORP'S PLANNING INPUT ASSUMPTIONS

Q Please provide a summary of your testimony with respect to the deficiency dates selected by PacifiCorp in the most recent proposed Schedule 37.

A In Order 10-488, the Commission required that the deficiency date be set at the earliest on-line or start date of a major resource acquisition according to the most recently acknowledged Integrated Resource Plan. Accordingly, PacifiCorp set the "non-renewable deficiency period beginning in 2028 coincident with the next major resource acquisition in the [2015] IRP preferred portfolio."[1]

It is my strongly held opinion that the 2028 non-renewable deficiency start date is based on a flawed premise. Understanding the basis of this premise requires a fair bit of background about the 2015 IRP – and now 2017 IRP – analysis put forward by PacifiCorp.

To explain why the 2028 deficiency dates put forward in Schedule 37 are inappropriate, we must examine the process that generated the 2028 deficiency date and the 2015 IRP. Resource deficiencies at PacifiCorp are driven, almost exclusively, by coal plant retirements. As such, a substantial amount of my testimony will explain how the Company assessed coal plant retirements for the 2015 IRP and how this process was biased and designed to select against plant retirements.

It would be difficult to overstate just how important PacifiCorp's 2015 coal plant retirement assessment—or lack thereof—is for PacifiCorp's short- and long-term resource planning. Renewable portfolio standard planning, QFs,

1 Opening Testimony of Brian S. Dickman at PAC/100, Dickman/4 (Oct. 14, 2016).

transmission justifications, and the Company's long-term fuel contracts are all based on an embedded set of assumptions aimed at retaining the Company's coal fleet as long as feasible.

I have testified on behalf of other clients numerous times about the PacifiCorp's coal plant planning process. In this case, this same process adversely impacts QF providers and must be addressed.

Q You just stated that the Company fails to assess coal plant retirements. What are PacifiCorp's Volume III IRP analyses if not coal plant assessments?

A In the 2013 and 2015 IRPs, PacifiCorp provided additional analyses of selected coal units in "Volume III" appendices. These analyses focus on specific coal units with environmental compliance requirements within a two- to four-year window of the action plan. By design, these analyses both are limited to a relatively small subset of PacifiCorp's units and do not examine decisions in the period of concern to the instant case (i.e., outside of the action plan window).

My contention is that in the 2015 IRP, PacifiCorp failed to assess reasonable coal plant retirement schedules and therefore completely failed to assess reasonable deficiency dates for the QF tariff proposed here.

In addition, I will show that the Company's 2015 IRP relies on an outdated set of assumptions with respect to requirements under the Clean Air Act. EPA's promulgation of a final regional haze rule in Utah earlier this year rendered the 2015 IRP preferred portfolio—and the basis of the Company's deficiency date—inconsistent with environmental rules.

Q Are you seeking to re-litigate the 2015 IRP in this case?

A No. While there were substantial elements of the 2015 IRP with which I disagreed, the basic elements of the 2015 IRP action plan as acknowledged by the Commission are not at issue here. However, the Commission acknowledgement of the 2015 IRP is limited to items in the action plan period, leaving the process of the extended period—including major resource acquisitions—well outside of the Commission's acknowledgement. Additionally, I understand that the purpose of this proceeding is to take into account the unforeseen changes in the regulatory environment since the acknowledgment of the 2015 IRP, including the enactment of SB 1547 and the additional information related to the impact of pollution control regulations on coal plant retirements, which were raised as issues earlier in these proceedings.

In Commission Order 16-307, which precipitated this docket, Staff argued (and the Commission adopted the view) that "while the starting point for avoided cost price inputs is the utility's last acknowledged IRP, *the reasonableness of the IRP inputs are subject to challenge during the review of avoided cost prices*."[2]

Staff then argued the following:

> **The date of PacifiCorp's next major resource is not an input of the IRP**; it is the result of complex modeling considering a variety of scenarios. Staff acknowledges that changing some assumptions underlying the selection of 2028 as the resource acquisition year may change the outcome of the analysis. However, such a result is not apparent here. The possible early shut down of two coal plants and an increase in anticipated front-office transactions does not

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2 Re PacifiCorp, dba Pacific Power, Schedule 37 Avoided Cost Purchases from Eligible Qualifying Facilities, Docket No. UM 1729(1), Order No. 16-307 at Appendix A at 8-9 (Aug. 18, 2016) (emphasis added).

> necessarily lead to a resource acquisition date in 2024 rather than 2028.[3]

I respectfully disagree. PacifiCorp created a unique mechanism to evaluate long-term coal plant retirements in the 2015 IRP. The mechanism *itself is an input of the IRP*. Through the use of this input assumption the Company effectively pre-selected 2028 as the first year in which a retirement would occur—and hence the date of the first major resource acquisition.

In Order 11-505, the Commission affirmed that "the IRP process, while complex, *is not a litigated proceeding* in which a utility's estimates of the costs of its resources are subjected to extensive discovery."[4]

Resource planning models are, indeed, complex. But the outcomes—including the resource acquisition year—are not inevitable or created from whole cloth. They are a direct consequence of the inputs used in the model, including the structure, constraints, and costs. As a model is increasingly constrained, outcomes become inevitable results of key assumptions. PacifiCorp's 2015 IRP made substantial key input assumptions that locked in the resource deficiency date.

In the resource planning and modeling world, inputs can take a variety of forms. The Commission is deeply familiar with inputs of fuel prices, emissions prices and restrictions, renewable energy requirements, and capital costs. Less apparent are inputs such as toggles within the modeling framework that either allow or restrict certain behaviors. Some common resource planning inputs that

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[3] Id. (emphasis added).

[4] Re Investigation Into Resource Sufficiency Pursuant to Order No. 06-538, Docket No. UM 1396, Order No. 11-505 at 11 (Dec. 13, 2011) (emphasis added).

usually lie below the surface include minimum or maximum builds, “must run” dispatch requirements, technology co-dependencies,[5] thermal transmission limits, market purchase caps, whether emissions prices are included in dispatch considerations, and whether the model can retire non-economic units “endogenously.” These are, by any definition, inputs. Different input assumptions for these variables can—and do—change outcomes substantially. PacifiCorp’s 2015 IRP made two substantial input assumptions that virtually guaranteed a 2028 resource deficiency date.

Q What inputs were set by the Company that “virtually guaranteed” a 2028 resource deficiency date?

A First, the Company hard coded all retirement dates into the model under the umbrella of what were termed “Regional Haze Scenarios.” I have no doubt that when the Company created its reference and three alternative regional haze scenarios, it designed the cases such that Regional Haze Scenario 3 would prevail on a cost basis, prior to releasing the scenarios to the public input process. As I will argue below, the Regional Haze Scenario 3 was less stringent (i.e., less costly) than the Company’s actual Clean Air Act requirements under the Regional Haze Rule, and thus was virtually guaranteed to come in at a lower cost than the scenario that complied with the law.

Second, the Company turned off a key element in modern resource planning: endogenous unit retirement, an issue which I will discuss in more depth later.

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5 A “co-dependency” is where the model is constrained such that one resource is not built without a specific trigger occurring at another resource.

These two assumptions—which were made at the input stage of the IRP process and elicited substantial comment and concern—guaranteed an outcome in which the first resource deficiency period could not be earlier than 2028.

In its review of the 2015 IRP, the Commission recognized the inherent imbalance between PacifiCorp's regional haze scenarios and required that PacifiCorp "use the same regional haze assumptions when directly comparing portfolios."[6]

III. PACIFICORP'S 2015 NON-RENEWABLE DEFICIENCY DATE IS BASED ON A FLAWED METHODOLOGY

Q Please describe your understanding of how the non-renewable deficiency date was set in Schedule 37.

A In Order 10-488, the Commission required that the deficiency date be set on the earliest on-line or start date of a major resource acquisition according to the most recently acknowledged Integrated Resource Plan. Accordingly, PacifiCorp set the "non-renewable deficiency period beginning in 2028 coincident with the next major resource acquisition in the [2015] IRP preferred portfolio."[7]

Q In brief, why is this 2028 next major resource acquisition assumption flawed and outdated?

A PacifiCorp's IRP model only selects major resource acquisitions when the Company's coal units retire, and during the 2015 IRP process, PacifiCorp maintained tight control of the coal retirement assessment. The Company's IRP analysis was ***flawed*** because it precluded economically efficient coal retirements, was ***biased*** because it was selected arbitrarily and precluded earlier resource

6 Re PacifiCorp, dba Pacific Power, 2015 Integrated Resources Plan, Docket No. LC 62, Order No. 16-071 at Appendix A at 2 (Feb. 29, 2016).

7 Opening Testimony of Brian S. Dickman at PAC/100, Dickman/4.

additions, and is ***outdated*** because it relied on assumptions about renewable energy requirements and EPA's regional haze rule that is no longer valid. To the same degree that Oregon SB 1547, a change in law that extended the state's renewable portfolio standard, triggered the instant case before the Commission, EPA's final Federal Implementation Plan for Utah rebuked a key assumption of PacifiCorp's 2015 IRP.

Arriving at how EPA's final regional haze rule impacts the Company's assessment of a 2028 non-renewable deficiency date requires background on how PacifiCorp conducted the 2015 IRP and on one key set of assumptions used by the Company.

Q What is the basis of the 2028 date selected by PacifiCorp for the non-renewable deficiency date?

A In the Company's 2015 IRP, a new 423 MW J-class combined cycle combustion turbine is built in the preferred portfolio in 2028 when all four Dave Johnston coal-fired units retire.[8] Notably, the Company also assumes an acquisition of 268 MW of "front office transactions," or shaped market energy purchases, in the same year.

The year 2028 is the first year in the IRP when any coal unit retires without being repowered as natural gas. So, while according to the Company 2015 IRP both Naughton 3 and Cholla 4 retire (in 2018 and 2025 respectively), PacifiCorp does not consider the repowering of either station a "major resource acquisition" because the utility simply continues to use the same facilities.

[8] Re PacifiCorp, dba Pacific Power, 2015 Integrated Resource Plan, Docket No LC 62, PacifiCorp's 2015 IRP at 196 (Mar. 31, 2015) (including Case C05a-3Q in Preferred Portfolio).

The fact that a new resource acquisition (the combined cycle combustion turbine) only occurs when a PacifiCorp coal plant (Dave Johnston) is retired is indicative of the current state of PacifiCorp's system, and an important element of the utility's planning. Over the last four years, PacifiCorp has projected relatively low native demand growth, a value that keeps shrinking. The 2015 IRP projected less than one percent peak and energy growth, before demand-side management and distributed resources. PacifiCorp will not assess the need for a major resource acquisition until some component of its existing coal fleet retires. PacifiCorp has carefully engineered its planning process to invariably preclude this option, to the detriment of both ratepayers and QF providers.

Q What is the basis of PacifiCorp's 2028 retirement date for Dave Johnston in the 2015 IRP?

A The decision to retire Dave Johnston by 2028—or rather by December 31, 2027—is not an economic decision *per se*, but one driven by PacifiCorp's current depreciable life of the plant[9] in non-Oregon states.[10] In the IRP, PacifiCorp *never* assessed any date for the retirement of Dave Johnston other than December 31, 2027.

In fact, PacifiCorp's 2015 IRP very carefully avoids assessing economic coal retirements for almost all the Company's coal fleet, a subject of extensive

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[9] Id. at 8 ("The option to shut down Dave Johnston Unit 3 by the end of 2027 as an alternative to installation of SCR coincides with the currently approved depreciable life of the Dave Johnston plant.").

[10] Note that while the retirement date for Dave Johnston in other PacifiCorp states is 2028, the Oregon end-of-life date for the plant is in 2023. Re PacifiCorp, dba Pacific Power, Petition to File Preliminary Depreciation Study, Docket No. UM 1329, Order No. 08-327 at 2 (June 17, 2008).

comment by parties in the 2015 IRP and a substantial component of discussion during the development of the 2017 IRP.

Q What is the importance of assessing economic coal retirements in the IRP process with respect to this proceeding?

A The deficiency dates that guide the construction of the QF tariffs, for both non-renewable and renewable resources, are fully dependent on the assumption of when coal units retire in PacifiCorp’s fleet. In the 2015 IRP, PacifiCorp created an analysis process that precluded meaningful assessment of coal unit retirements and effectively hard coded in coal retirement dates. The 2028 major resource acquisition that follows the Dave Johnston retirement is a relatively arbitrary date driven entirely by subjective PacifiCorp choices—not by fundamental economics or least cost planning.

Q Why was PacifiCorp’s 2015 IRP analysis flawed?

A The Company’s 2015 IRP analysis was flawed because it failed to assess a least cost framework for the retirement or retrofit of the Company’s existing coal fleet.

Q How did PacifiCorp determine the coal retirement dates in the 2015 IRP?

A The 2015 IRP coal retirement dates are based on the Company’s subjectively selected “Regional Haze Scenarios” developed specifically for that IRP. Ostensibly, the Company designed these Regional Haze Scenarios as a strategy for dealing with multiple simultaneous regional haze compliance requirements across its coal fleet. Over the last decade, EPA’s regional haze rule has firmly established a number of emissions requirements for PacifiCorp, first requiring reductions of sulfur dioxide (“SO_2”) and particulate matter (“PM”) and more recently requiring cuts in oxides of nitrogen (“NOx”). To achieve these reductions, PacifiCorp has installed hundreds of millions of dollars of pollution control equipment, including flue gas desulfurization ("FGD"), baghouses, low-NOx burners, and—more recently—selective catalytic reduction ("SCR").

Other utilities, faced with these requirements, assess the economic condition of the individual units in their coal fleet, seeking to make the best economic choices for consumers on a unit-by-unit basis.

PacifiCorp, instead, has used these Regional Haze Scenarios wherein it combined decisions about its coal units' compliance options in ways that are at best arbitrary and at worst biased. The Company's regional haze scenarios lock in coal units that would likely be retired if it ran the SO model correctly.

Q How do other utilities handle environmental compliance requirements in planning?

A I have been involved in over a dozen cases with utilities examining environmental obligations, and assessed many more IRPs that reviewed these same decisions. While utilities have developed different strategies to review near- and mid-term obligations, their strategies share a common theme: Each individual coal unit's costs, risks, and opportunities are assessed in order to reduce and optimize the cost of the overall portfolio. PacifiCorp is the only utility with such a substantial coal fleet that I have encountered that does not make these decisions on a unit-by-unit basis.

Q Is PacifiCorp's IRP model equipped to make economic coal retirement assessments?

Yes. PacifiCorp's long-term planning model, System Optimizer, is well equipped to make these types of assessments and can examine economic retirements as a mechanism of reaching compliance—if the Company allows it to do so. The Company's 2015 IRP did not allow SO to make independent decisions about retirements – what PacifiCorp has previously called "endogenous" retirement decisions. [11] PacifiCorp's non-renewable deficiency date would almost certainly be different if the Company were using an "endogenous" model framework and valid regional haze assumptions.

In the 2013 IRP, PacifiCorp used an endogenous framework and came to the startling conclusion that under "low" gas prices and "high" CO_2 prices, "nearly all of PacifiCorp's existing coal-fired resources are retired or converted to natural gas prior to 2032."[12] In fact, under each case with low gas and higher CO_2 prices, *nearly every one* of PacifiCorp's coal fleet retired in 2023 or before.[13] This seemingly extreme scenario was, in fact, very similar to the reference conditions assessed by PacifiCorp in the 2015 IRP. The "low" gas prices of the 2013 IRP[14] were relatively close to the base gas prices used in the 2015 IRP,[15] and

11 "Endogenous" in this case means "occurring within," where endogenous retirement decisions are decisions made by the computer program to retire existing units when economically attractive, rather than hard coded by a planner.

12 Re PacifiCorp, dba Pacific Power, 2013 Integrate Resource Plan, Docket No. LC 57, PacifiCorp's 2013 IRP at 209 (Apr. 30, 2013).

13 See Re PacifiCorp, dba Pacific Power, 2013 Integrate Resource Plan, Docket No. LC 57, Sierra Club's Preliminary Comments at 4 (Aug. 22, 2013).

14 Docket No. LC 57, PacifiCorp's 2013 IRP at 185 (including Figure 7.14. Henry Hub Natural Gas Prices from the Low Underlying Forecast. 2015 price is approximately \$3/MMBtu, rising to \$4/MMBtu in 2020, and \$5/MMBtu by 2025).

15 Docket No LC 62, PacifiCorp's 2015 IRP at 4 (comparing Power Prices and Natural Gas Prices among Recent IRPs. Price starts \$4/MMBtu in 2015, is maintained until 2019 and rises to \$6/MMBtu by 2024).

the "high" CO_2 prices in the 2013 IRP[16] were approximately commensurate with the CO_2 price put forward in the 2015 IRP.[17] While not a perfect analog, these similarities suggest that a correctly executed 2015 IRP would have likely seen a substantial coal fleet retirement, as occurred in the 2013 IRP.

Q So why didn't PacifiCorp's 2015 IRP result in substantial coal unit retirements and hence new major resource acquisitions?

A One of the primary reasons that PacifiCorp's 2015 IRP did not result in substantial coal unit retirements is because the Company employed a new Regional Haze Scenario mechanism, wherein rather than making individual coal assessments, the IRP could only select amongst these relatively arbitrary Regional Haze Scenarios.

In the 2015 IRP, the Company bypassed System Optimizer's capabilities to determine endogenous retirements and input a schedule for the retirements of its coal units in all but one scenario (C14a). Instead, the Company used the Regional Haze Scenarios as a cohort of manually-selected retirement and retrofit decisions—far from an optimal framework. None of the Company's scenarios tested substantial early coal retirements and only one of these scenarios is even close to consistent with EPA's requirements.

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16 Docket No. LC 57, PacifiCorp's 2013 IRP at 168 (including CO_2 Price Scenarios. High CO_2 price starts at $13.5/ton in 2020 and rises to $75/ton in 2032).

17 Docket No LC 62, PacifiCorp's 2015 IRP at 147 (indicating Nominal CO_2 Price Assumptions for the Portfolio Development Process. Price starts ~$20/ton in 2020 and rises to $75/ton in 2034).

The Company's Regional Haze Scenarios were as follows in the table below.[18]

Figure 1. Table 7.2 from PacifiCorp 2015 IRP on Regional Haze Scenarios.

Coal Unit*	Reference	Scenario 1	Scenario 2	Scenario 3
Dave Johnston 1	Shut Down Dec 2027	Shut Down Mar 2019	Shut Down Mar 2019	Shut Down Dec 2027
Dave Johnston 2	Shut Down Dec 2027	Shut Down Dec 2027	Shut Down Dec 2023	Shut Down Dec 2027
Dave Johnston 3	SCR Mar 2019	Shut Down Dec 2027	Shut Down Dec 2027	Shut Down Dec 2027
Dave Johnston 4	Shut Down Dec 2027	Shut Down Dec 2032	Shut Down Dec 2032	Shut Down Dec 2027
Hunter 2	SCR Dec 2021	Shut Down Dec 2032	Shut Down Dec 2024	Shut Down Dec 2032
Huntington 1	SCR Dec 2022	Shut Down Dec 2036	Shut Down Dec 2024	SCR Dec 2022
Huntington 2	SCR Dec 2022	Shut Down Dec 2021	Shut Down Dec 2021	Shut Down Dec 2029
Jim Bridger 1	SCR Dec 2022	Shut Down Dec 2023	Shut Down Dec 2023	SCR Dec 2022
Jim Bridger 2	SCR Dec 2021	Shut Down Dec 2032	Shut Down Dec 2028	SCR Dec 2021
Wyodak	SCR Mar 2019	Shut Down Dec 2039	Shut Down Dec 2032	Shut Down Dec 2039

*Common to all scenarios: Carbon 1&2 shut down 2015; Colstrip 3&4 SCR 2023/2022, respectively; Craig 1&2 SCR 2021/2018, respectively; Hayden 1&2 SCR 2015/2016, respectively; Naughton 1&2 shut down 2029; Naughton 3 gas conversion 2018, shutdown 2029; Hunter 1&3 SCR 2021/2024, respectively; and Bridger 3&4 SCR 2015/2016, respectively.

The problem with looking at these scenarios as coherent wholes is that it precludes the Company from assessing if individual coal units are non-economic. By coupling multiple decisions together, the Company blurred, and ultimately eliminated, any assessment of coal unit retirements that were not in the immediate future.

I conclude that PacifiCorp's 2015 IRP preferred portfolio selection was *flawed* because it precluded economically efficient coal retirements.

Q Why do you believe that the Regional Haze Scenarios developed for the 2015 IRP were biased?

A The amount of information that the Company released on their strategy for the development of the Regional Haze Scenarios in the 2015 IRP was extremely

[18] Id. at 44 (including "State 111(d) Emission Rate Assumptions"). PacifiCorp acknowledged in discovery and discussions that this table was labeled in error and should have read "Regional Haze Scenarios."

limited and non-specific given the incredible importance of the decisions made. The 2015 IRP itself has exactly one paragraph with extraordinarily vague language about these "potential scenarios that might, pending agency support, achieve an appropriate balance of economic justification."[19]

Most disconcertingly, in the public input process leading up to the final selection of scenarios, PacifiCorp *changed the scenarios*, adding a third regional haze scenario that, astoundingly, was lower cost than any other scenario and ultimately selected as the preferred portfolio.

In an August 7, 2014 public input meeting, PacifiCorp presented *two* regional haze alternative scenarios, both of which contemplated shutting down at least one Dave Johnston unit by 2019.[20]

In the next meeting that discussed regional haze scenarios, on November 14, 2014, PacifiCorp added Regional Haze Scenario 3, explaining only that "upon reviewing Regional Haze retirement assumptions on the timing of new resources, Case C05a-3 was added to replicate the Oregon RPS unbundled REC strategy with alternative coal retirement assumptions."[21] This was the first time that Regional Haze Scenario 3 had been introduced to stakeholders. The results of this run were not disclosed until the publication of the final IRP, when it turned out—unsurprisingly—that this last-minute addition had prevailed as the least cost option and preferred portfolio.

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[19] Docket No. LC 62, PacifiCorp's 2015 IRP at 148.
[20] Exhibit REC-CREA/203 at 65-66.
[21] Exhibit REC-CREA/204 at 25.

In the discovery process following, parties asked PacifiCorp to specifically address how the dates for the shut down or retrofits in the regional haze scenarios had been selected. PacifiCorp provided a paragraph explaining that "the hypothetical Regional Haze scenarios are intended to provide information for stakeholder review and consideration, but they may or may not be driven by current obligations and … have not been reviewed for acceptability with any agencies, regulators, or joint owners of affected facilities."[22] The Company stressed that "the provided scenarios reflect *hypothetical* [emphasis in original] Regional Haze compliance scenarios for the purpose of assessing relative portfolio impacts." The term "hypothetical" was repeated five times in the paragraph.

I am concerned that PacifiCorp specifically created, on a last-minute basis, a scenario that locked in the vast majority of their coal fleet until 2028, intentionally preventing any form of major resource acquisition until after that date.

I conclude that PacifiCorp's 2015 IRP preferred portfolio selection was *biased* because PacifiCorp created a new subjective portfolio outside of the public input process, that the portfolio is inconsistent with environmental rules, and that it harmed specific parties. This scenario was not explained, vetted, or substantiated, and yet it formed the basis of the preferred portfolio.

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22 Exhibit REC-CREA/205, Fisher/3.

Q Does the 2017 IRP suffer from the same fundamental problem as the 2015 IRP?

A Yes. In the 2017 IRP, PacifiCorp once again has disabled the option to examine endogenous coal retirements, instead opting to examine five different "regional haze alternatives" which all presuppose the continued existence of the coal fleet through 2028 (Jim Bridger 1) at the earliest.

Compelled by stakeholders, PacifiCorp reluctantly included a regional haze scenario, titled "RH-6," in which Hunter 1, Hunter 2, Huntington 1, Huntington 2, Jim Bridger 1, and Jim Bridger 2 were allowed to retire instead of installing SCRs to meet Regional Haze obligations. In this scenario, the model opted to retire Jim Bridger 2 in 2022,[23] rather than install SCR, saving between $193-$443 million relative to the reference case, in which no retirements are allowed.[24] The Company rejected this case, opting to pursue as the preferred portfolio a case in which PacifiCorp does not meet its regional haze obligations at Hunter 1, Hunter 2, Huntington 1, Huntington 2, Jim Bridger 1, or Jim Bridger 2, and these units are allowed to continue operation, even if not cost effectively.

Q What is the replacement resource when Jim Bridger 2 retires early in RH-6 in the 2017 IRP?

A When the 356 MW Jim Bridger 2 unit retires, PacifiCorp's IRP model assumes the utility simply picks up an extra 616 MW of "front office transactions," or short-term energy market options.

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23 Re PacifiCorp, dba Pacific Power, 2017 Integrated Resource Plan, Docket No LC 67, PacifiCorp's 2017 IRP at 190 (Apr. 4, 2017).

24 PacifiCorp's 2017 IRP at 238 (including Stochastic Risk Adjusted PVRR by Price Scenario, Regional Haze Cases and Mass-based carbon cap "B" (MCB), range from high to low gas, respectively).

Q Would PacifiCorp consider replacing a large unit like Jim Bridger 2 with market purchases as a long-term solution?

A Probably not. Most utilities would balk at the idea that they increase market exposure so substantially for an extended period of time, and in the past, PacifiCorp has typically assessed coal unit retirements against a replacement portfolio of resources – not just market purchases.

Q Is the endogenous coal retirement explored by PacifiCorp in RH-6 comprehensive with respect to potentially non-economic coal units?

A No. The Company's model fails to examine the economics of Jim Bridger 3 & 4, Craig 1 & 2, Hayden 1 & 2, Naughton 1 -3, or Wyodak. I believe that some, if not all, of these units would be selected by the model for near-term endogenous retirement – even without a new regional haze obligation. PacifiCorp's modeling shows that when larger capacities of coal-fired units retire, such as Dave Johnston in 2028, the model selects a new thermal resource.

Again, this simply demonstrates that PacifiCorp's modeling methodology – and choice to not assess endogenous coal unit retirements or the resulting requirement for new generation – are input assumptions.

PACIFICORP'S 2015 NON-RENEWABLE DEFICIENCY DATE IS BASED ON OUTDATED ASSUMPTIONS

Q Why is PacifiCorp's 2015 IRP analysis outdated?

A PacifiCorp's 2015 IRP analysis is outdated for multiple reasons: (a) the 2015 IRP could not take into account the impact of SB 1547, (b) gas and electricity price projections have fallen substantially, impacting the economic viability of PacifiCorp's fossil fleet, and (c) the analysis relied on an assumption that EPA's regional haze rule would not impact PacifiCorp's Utah plants, and is inconsistent with a Federal Implementation Plan, promulgated just this year.

Q How does SB 1547 render the Company's 2015 IRP analysis outdated?

A The fact that SB 1547 substantially changed the PacifiCorp's renewable procurement requirement is a key element in the genesis of this proceeding. The requirements of SB 1547 are only addressed on an *ad hoc* basis in PacifICorp's filing. PacifICorp states that "the 2015 IRP and 2015 IRP Update concluded that the Company did not identify an immediate need to acquire new renewable resources because the Company could comply with its Oregon RPS requirements (including the increased obligations imposed by SB 1547) through the purchase of unbundled RECs."[25] Neither the 2015 IRP and 2015 IRP Update were tested with SB 1547 obligations, and thus this assertion is neither demonstrated nor vetted. As I will describe later, PacifiCorp's most recent public assessment of the renewable energy market suggests that under both 2015 IRP and 2015 IRP Update cost assumptions the Company would, in fact, procure near-term physical renewable resources. This undermines PacifiCorp's assertion that compliance obligations would simply be fulfilled with unbundled REC purchases.

Q Why would lower gas and electricity price projections cause PacifiCorp's 2015 IRP to be outdated?

A A long-term plan is relatively sensitive to fuel and market electricity prices. As demonstrated by the actions of PacifiCorp and other utilities, as gas (and hence market) prices fall, existing resources lose their relative value to ratepayers. An optimization process that assesses the value of both new and existing resources

[25] Opening Testimony of Brian S. Dickman at PAC/100, Dickman/4.

would increasingly select against existing higher cost resources. In PacifiCorp's case, prior IRPs showed definitively that when gas and electricity market prices fell, PacifiCorp found value in retiring existing coal-fired units. PacifiCorp's 2015 IRP Update gas prices are substantially below the 2015 IRP forecasts.

Q Are any of the regional haze cases of the 2015 IRP examined by PacifiCorp consistent with environmental rules?

A Yes – one. The Reference Case examined by PacifiCorp was the only case consistent with environmental rules examined in the 2015 IRP, but it was not the basis of the Company's preferred plan.

As I noted previously, PacifiCorp based the 2015 preferred portfolio, called C05a-3Q, on Regional Haze Scenario 3, which required *no NOx controls* at Hunter 1, Hunter 2, or Huntington 2 (see **Error! Reference source not found.** on page 22).

On July 5, 2016, EPA promulgated a Federal Implementation Plan for Utah requiring the installation of SCRs at Hunter and Huntington (or the retirement of those units) by July 2021,[26] an expensive proposition which was not examined at all by PacifiCorp in the 2015 IRP preferred portfolio.

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[26] EPA Approval, Disapproval and Promulgation of Air Quality Implementation Plans, 81 Fed. Reg. 43,894, 43,907 (July 5, 2016) ("For the Hunter and Huntington BART units, we find that BART for NOX is SCR + LNB/SOFA, represented by an emission limitation of 0.07 lb/MMBtu (30-day rolling average)"). The Regional Haze Rule requires installation of BART controls no later than five years after the promulgation of the rule, or July 2016.

Q Did parties in the 2015 IRP comment on the potential that the regional haze portfolios were inconsistent with environmental rules?

A Yes. In comments before this Commission on the 2015 IRP, Sierra Club (an intervenor in OR docket LC 62) noted that PacifiCorp's preferred portfolio was likely not compliant with an impending regional haze requirement.[27] In particular, Sierra Club was concerned about a proposed regional haze federal implementation plan for Utah that would have required stringent controls at the Hunter and Huntington plants by 2021. PacifiCorp's Reference case appropriately captured this risk. No other scenario did.

I conclude that PacifiCorp's 2015 IRP preferred portfolio selection is *outdated* because it does not reflect a substantial requirement from EPA.

OPTIMIZED 2015 IRP SCENARIO INDICATES NON-RENEWABLE DEFICIENCY IN 2021

Q You leveled two allegations against PacifiCorp's 2015 IRP preferred portfolio: that it was not selected economically and that it is inconsistent with environmental rules. Did you test for an optimized scenario that *was* consistent with EPA's regulations?

A I did test PacifiCorp's 2015 model with an endogenous retirement framework and regional haze options consistent with EPA's requirements. On behalf of Sierra Club, in mid-2015 Synapse acquired the SO model (at considerable expense) and ran several alternatives to the Company's Regional Haze Scenario framework.

We employed the Company's model assumptions with very few modifications, but allowed the model to select endogenous coal unit retirements, diligently ensuring that the model was appropriately capturing retirement costs

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[27] Re PacifiCorp, dba Pacific Power, 2015 Integrate Resource Plan, Docket No. LC 62, Sierra Club's Final Comments at 15 (Oct. 15, 2015). Please note scrivener's error: "Regional Haze federal implementation plan in Wyoming" should have read "in Utah."

with PacifiCorp's assumptions. We allowed the SO model to retire coal units based on economics rather than book life. In our model run, we allowed the model to choose investments and retirements at all plants beginning in 2020 under a mass-based Clean Power Plan compliance pathway.

We presented our model runs from this analysis in comments on behalf of Sierra Club in 2015. I have attached the analysis paper to this testimony as Exhibit REC-CREA/202.[28]

Q What were your findings from your re-analysis of the 2015 IRP?

A We found in our model run that System Optimizer chose a significantly different coal unit retirement schedule when allowed to retire units based on economics. New economic retirements began in 2019 with Hayden 1 & 2 and Craig 1, followed by Hunter 1 and Cholla 4 in 2020, and then Hunter 3 in 2023.[29] The differences in retirements in PacifiCorp's Preferred Portfolio, in Figure 2, and the Synapse sensitivity run, in Figure 3, are clear..

28 Re PacifiCorp, dba Pacific Power, 2015 Integrate Resource Plan, Docket No. LC 62, Sierra Club's Comments on PacifiCorp's 2015 IRP at 27-47 (Aug. 27, 2015) (reviewing the use of the System Optimizer model in PacifiCorp's 2015 IRP).

29 Full set of coal retirements by year during analysis period (2015-2034): 2015: Carbon 1 & 2, Naughton 3; 2019: Craig, Hayden 1 & 2; 2020: Cholla 4, Hunter 1; 2022: Naughton 1; 2023: Hunter 3; 2027: Dave Johnston 1-4; 2030: Naughton 2.

Figure 2. Generation capacity by year: PacifiCorp Preferred Portfolio

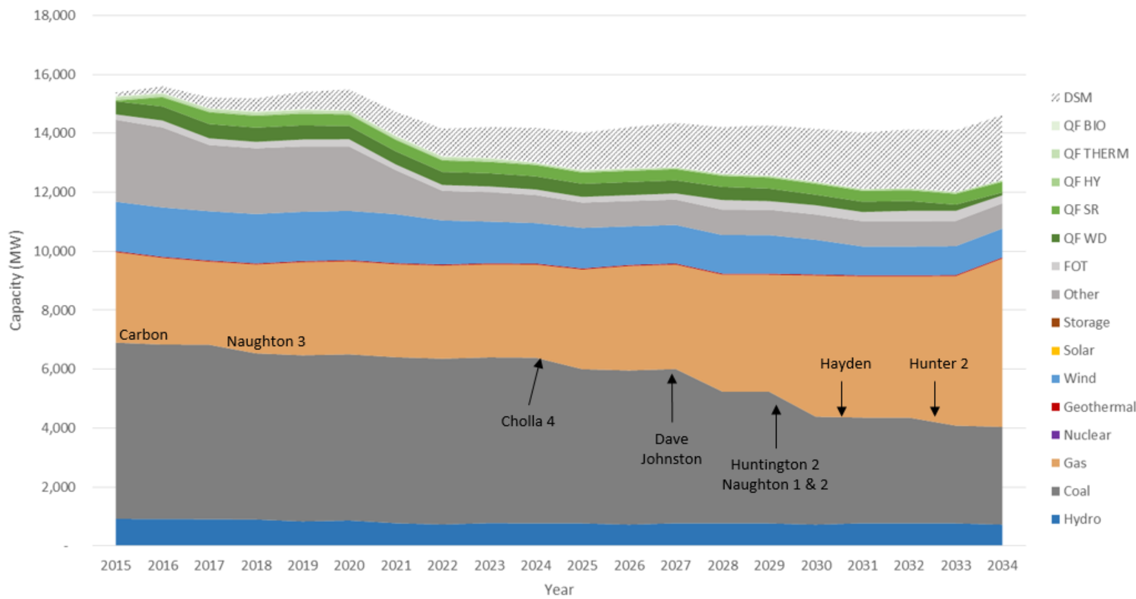
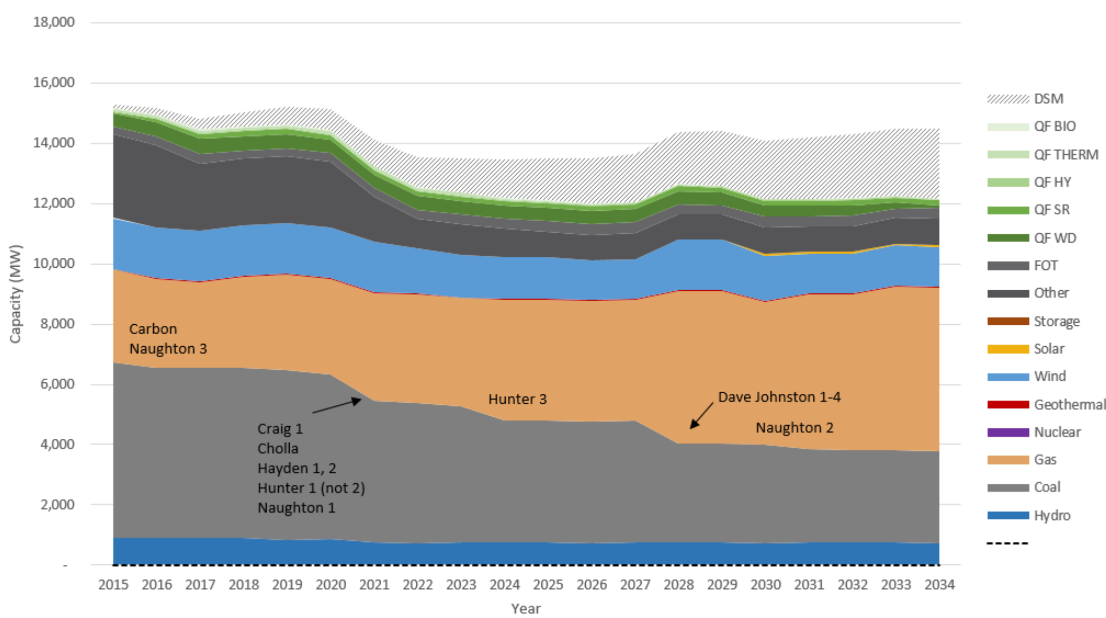


Figure 3. Synapse Sensitivity Run with endogenous retirements and mass-based CPP compliance (low CO2 price) [30]



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30 Exhibit REC-CREA/202. Scenario shown here represents case "B" in paper. "Other" category represents PPAs held by PacifiCorp.

Q Why is the analysis of the economic lives of the units in PacifiCorp's coal fleet relevant to this proceeding?

A As I discussed earlier, the Commission has ordered that resource deficiency is demarcated by the first major resource acquisition in the action plan of an acknowledged utility IRP. The deficiency period for both non-renewable and renewable resources begins in 2028, coincident with both the retirement of the Dave Johnston plant and the next major resource acquisition under the Preferred Portfolio in PacifiCorp's 2015 IRP.

The Synapse System Optimizer sensitivity run shows that a true least-cost portfolio—which follows the law—would have resulted in the retirement of multiple coal units beginning in 2020, much earlier than in the Preferred Portfolio of the 2015 IRP. The coal retirements would necessitate a major resource acquisition prior to the Company's proposed insufficiency date of 2028.

Based on the results of the Synapse System Optimizer run and fully consistent with the 2015 IRP, I propose a non-renewable deficiency date of 2021. This date is consistent with EPA's Regional Haze findings on the Hunter and Huntington units and occurs mid-way through the slate of unit retirements in our alternative study. This is the date at which one might have reasonably expected a thermal deficiency due to the economic retirement of one or more PacifiCorp units according to the 2015 IRP.

<u>PACIFICORP'S RENEWABLE DEFICIENCY DATE IS INCONSISTENT WITH RENEWABLE RFP FINDINGS</u>

Q Please describe your understanding of how the renewable deficiency date was set in the most recent Schedule 37.

A I have not been engaged in the iterative process of the last nine months, but I understand the process as follows. On March 1, 2016, PacifiCorp issued a Schedule 37 that it believed was consistent with its 2015 IRP as acknowledged by the Commission on February 29, 2016. This schedule did not include a renewable deficiency period, stating that "[s]ince 2015 IRP's action plan does not include acquisition of any renewable proxy resource, the sufficiency period for renewable avoided cost rates extends beyond the end of the published term."[31]

A week and a half later, on March 11, 2016, Oregon signed into law SB 1547, requiring a substantial increase in renewable energy acquisitions as well as divestiture from coal-fired power. Following a public meeting, on March 23, 2016 the Commission rejected PacifiCorp's March 1st Schedule 37 and directed parties to work together to assess the impact of SB 1547.

PacifiCorp provided a second revised Schedule 37 on June 21, 2016 proposing a 2018 renewable deficiency date. PacifiCorp's explanation supporting the 2028 deficiency date did not specifically address why the Company chose that date, only explaining that "the Company does not believe that SB 1547 renders the Company immediately deficient. The Company's current renewable energy

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[31] <u>Re PacifiCorp, dba Pacific Power, Application to Update Schedule 37 Qualifying Facility Information</u>, Docket No. UM 1729, Schedule 37 Avoided Cost Purchases from Eligible Qualifying Facilities Compliance Filing Docket UM 1610 at Appendix 2 at 2 (Mar. 1, 2016) (indicating Sufficiency and Deficiency Periods).

credit (REC) bank is sufficient through 2025."[32] The Company's testimony in this case states that, despite the 2018 "compromise position," "the 2015 IRP and 2015 IRP Update concluded that the Company did not identify an immediate need to acquire new renewable resources because the Company could comply with its Oregon RPS requirements (including the increased obligations imposed by SB 1547) through the purchase of unbundled RECs."[33]

On July 27, 2016, Staff provided a recommendation to the Commission that PacifiCorp file an amended Schedule 37 based on a renewable deficiency period of 2018. However, on August 18, 2016, the Commission ordered PacifiCorp to file a Schedule 37 "that is based on renewable and non-renewable deficiency periods beginning in 2028, cost and performance data from its acknowledged 2015 Integrated Resource Plan, and updated gas and electricity prices as required in an annual update."[34] The Commission's order unfortunately provided no basis for the 2028 demarcation within the body of the order. PacifiCorp's revised Schedule 37 complies with the Commission's order to use a 2028 deficiency date, but goes further stating the following:

> Because of significant reductions in the cost of renewable resources since the 2015 IRP was prepared, and because the Company's RPS compliance strategy is to continue to rely on unbundled REC purchases, if Schedule 37 assumes a renewable resource is acquired in 2028 (a departure from the acknowledged 2015 IRP) it should also reflect the most current estimates of the costs to acquire such a

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32 Re PacifiCorp, dba Pacific Power, Application to Update Schedule 37 Qualifying Facility Information, Docket No. UM 1729, Schedule 37 Avoided Cost Purchases from Eligible Qualifying Facilities Compliance Filing Docket UM 1610 at 3 (June 21, 2016) (indicating 2018 Renewable Resources Deficiency Period).

33 Opening Testimony of Brian S. Dickman at PAC/100, Dickman/4.

34 Docket No. UM 1729(1), Order No. 16-307 at 1 (emphasis added).

> resource if retail customers are to remain indifferent to purchasing the output of a renewable QF.

I agree that both a 2018 and a 2028 renewable resource acquisition date are departures from the 2015 IRP, but as I argued above, I believe that, in light of recent developments related to pollution control regulations under the Clean Air Act, the 2015 IRP's are no longer defensible whatsoever. Even assuming those deficiency dates ever had any economic merit, the dates are now completely arbitrary and contrary to economic analysis using PacifiCorp's own models and what are now well-established requirements under the Clean Air Act.

The assessment of a 2028 renewable resource acquisition date is inconsistent with both reasonable least cost planning as should have been performed in the 2015 IRP and the Company's 2016 renewable RFP process.

Q In what way is the 2028 renewable resource acquisition date inconsistent with reasonable least cost planning?

A The Company's support for a 2028 renewable resource date is entirely dependent on the assumption that a coal unit needs to retire prior to new renewable energy coming online and freeing transmission capacity. Indeed, the Company effectively implies that cost-effective renewable resources *would* be selected by System Optimizer but for the fact that existing coal units occupy transmission (and presumably already provide sufficient energy).

The Company states the following:

> Establishing a renewable resource deficiency period of 2028 aligns the assumed acquisition of a renewable resource with the anticipated retirement of the 762 MW Dave Johnston coal plant in eastern Wyoming. Retiring this plant will free up transmission capacity and

> provide access to more cost effective wind resources in eastern Wyoming for the benefit of customers.[35]

There are two problems here. First, the retirement of the Dave Johnston coal plant is not based on economics, but is instead based on PacifiCorp's depreciation date for the plant, which was hard-wired into the 2015 IRP without any defensible economic modeling. Second, the Dave Johnston plant is not entitled to the exclusive use of PacifiCorp's transmission.

Retirement based on book life rather than economic life fails to allow low-cost renewable energy to compete against PacifiCorp's coal units. The Company asserts that the availability of transmission is a barrier to the near-term acquisition of otherwise cost-effective renewables, but fails to consider any means of addressing these constraints, namely the economic retirement of the Dave Johnston unit—or any other coal unit. The use of a fixed coal retirement schedule excludes any option that an earlier coal retirement schedules—and earlier renewable procurement—would be any lower cost.

Q What would you expect for a renewable deficiency date if the Company had conducted least cost planning in the 2015 IRP?

A As I discussed earlier, the Company's firm (and late) coal retirement dates and failure to allow endogenous coal retirements resulted in an IRP that could not reasonably be considered least cost, and I showed evidence that even under the Company's 2015 IRP assumptions, multiple coal units would have retired in the early 2020s given the option to do so.

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35 Opening Testimony of Brian S. Dickman at PAC/100, Dickman/14.

The Company has insisted that in the 2015 IRP Update, renewable energy prices fell substantially from the 2015 IRP.[36] I take no position here on the current costs or performance of new renewable energy projects. If we take the Company at its word, I suspect that given substantial coal retirements in the early 2020s, including in central Utah, we could expect to see the IRP acquisition of Utah solar in near-term years (i.e., by 2022).

Q In what way is the 2028 renewable resource acquisition date inconsistent with the Company's 2016 renewable RFP process?

A The Company's 2016 renewable RFP process indicated that the Company would seek to acquire cost-effective physical renewable energy contracts in 2018. (This takes the Company at its word with respect to the expected current costs and cost trajectories of renewable energy used in the 2015 IRP Update.). By this measure, the avoidable resources are the resources that responded to the RFP process, and the date of deficiency is 2018.

Q Please explain why the Company's RFP process indicates that the Company should have been acquiring contracts for physical resources well before 2028?

A On April 20, 2016 PacifiCorp issued an RFP for renewable resources and renewable energy credits (RECs).[37] On July 26, 2016 the Company provided a public presentation to this Commission on the evaluation of bids received.[38] The results of this analysis are telling and inconsistent with the Company's position of a 2028 resource deficiency date.

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[36] Id. at PAC/100, Dickman/10-11.

[37] See Re PacifiCorp, dba Pacific Power, 2017-2020 Renewable Portfolio Standard Implementation Plan, Docket No. UM 1790, PacifiCorp's 2017-2020 RPIP at 2 (July 15, 2016).

[38] Exhibit REC-CREA/206.

The analysis conducted by PacifiCorp strove to assess the quantity of bids PacifiCorp should accept for both physical resources and RECs against simply waiting until PacifiCorp had a REC deficiency and building at that time. Clearly, if PacifiCorp determined that renewables offered today were cost-effective relative to its expected cost of renewables at a later date, PacifiCorp should seek to acquire those cost-effective resources today.

PacifiCorp broke the received bids into six tranches ("A" through "F"). It determined the cost of procuring each sequentially more expensive tranche. This information was compared against the hypothetical cost of procuring renewable energy at a later date, what PacifiCorp termed a "just in time" or "JIT" scenario.[39] PacifiCorp tested the benefits of near-term procurement against three different JIT scenarios. Each of the three JIT scenarios tested different assumptions about the future cost of renewable energy. JIT-1 was the most expensive hypothetical scenario, with renewable prices and performance equivalent to the 2015 IRP Update. JIT-3 used an assumption that renewable energy was substantially less expensive.

When PacifiCorp assumes that *future* renewable energy prices are low (i.e., JIT-3), it chooses not to buy real resources today. When PacifiCorp assumes that *future* renewable energy prices are relatively high (i.e., JIF-1), it chooses to procure RECs and renewable resources today.

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[39] The scenarios were called "just in time" because PacifiCorp would defer any physical renewable procurement until the year that the renewable energy was needed for RPS purposes.

Correspondingly, when PacifiCorp tested the shortlisted bids against its assumed proxy cost of renewable energy in the 2015 IRP Update (JIT-1), it found that it was cost-effective to procure the full suite of RECs *and* physical resources in the shortlist, or 388 MW.

When PacifiCorp tested the shortlist bids against even lowest projected renewable energy proxy costs (JIT-3), it determined that it was cost-effective to procure slightly less than 200 MW of physical resources, starting in 2018. In other words, PacifiCorp concluded that near-term acquisition of a suite of renewable resource (in excess of 100 MW) is the cost-effective compliance strategy under all of its scenarios, ranging from the 2015 IRP Update Costs in JIT-1 to the lower costs of JIT-3. At the end of the day, PacifiCorp chose neither of these pathways, inexplicably choosing to procure *no* physical resources from the RFP process. It instead indicated that it will continue to test the market for a physical resource in the future.

REC was not provided the costs and assumptions underlying PacifiCorp's RFP analysis, and thus I have been unable to vet PacifiCorp's analysis in this matter or determine if the analysis is accurate or reasonable.

The results of PacifiCorp's analysis are shown in the consolidated table below, based on data shown in the RFP presentation.

Table 1. Cost / (Benefit) of RFP tranches relative to PacifiCorp self-build options

Base Case assessment (July 26, 2016)[40]

RFP Tranches	Physical RE capacity (MW)	RECs (MW)	Customer Cost / (Benefit) ($M) of RFP Tranche relative to PacifiCorp self-build		
			JIT-1*	JIT-2	JIT-3**
RFP-A	0	72	($107)	($114)	($44)
RFP-B	0	243	($329)	($335)	($52)
RFP-C	94	381	($354)	($391)	($89)
RFP-D	189	504	($372)	($427)	($159)
RFP-E	241	504	($390)	($427)	($152)
RFP-F	388	504	($400)	($409)	($104)

* 2015 IRP Update

**International Renewable Energy Agency (2016)

This table shows that under the assumptions of the 2015 IRP Update (JIT-1), PacifiCorp would have found the procurement of the largest tranche of RFPs in group RFP-F, comprising both physical resources and RECs, to be cost-effective.

According to this same presentation, the procurement of at least some of the physical resources (at least 200 MW) would have started between 2018 and 2021.[41]

40 Exhibit REC-CREA/206 at 23, 28.
41 Id. at 27.

I take from this assessment that if PacifiCorp is to be taken at its word that renewable resource proxy costs are currently commensurate with the 2015 IRP Update, then it would have acquired a new major resource—i.e., a response to a bid—in 2018. This is deeply inconsistent with the 2028 proposed renewable deficiency date.

Q Are there any other notable components of PacifiCorp's evaluation of renewable energy bids in 2016?

A Yes. The PacifiCorp presentation makes clear that the Company not only considers Dave Johnston to be a transmission barrier for the procurement of cost-effective wind in Wyoming, but also considers Hunter and Huntington plants in Utah barriers to cost-effective solar in Utah. PacifiCorp's analysis shows that PacifiCorp actually restricts new solar procurement in Utah until Huntington 2 is retired in 2030. This suggests that if solar in Utah were allowed to compete against PacifiCorp's coal units, it might be selected as a cost-effective resource, regardless of PacifiCorp's need for RECs.

Q Does the 2017 IRP further affirm your assessment of the impact of PacifiCorp's existing units on the ability to acquire new renewable energy resources?

A Yes.

First of all, it should be noted that in nearly every case ran by PacifiCorp in the 2017 IRP, a substantial amount of new wind is built in 2021 in eastern Wyoming. Left to its own devices, the model selects between 200 and 300 MW of new wind in 2021 near the Aeolus substation in southeastern Wyoming.

Second, given the option to add additional transmission from Dave Johnston to Bridger, the IRP model adds 300 MW of wind in southeastern

Wyoming in 2021, and another 440 MW in 2020.[42] This affirms the concept that the existing coal generating stations are an obstruction to the passage of cost-effective wind, and that given the opportunity, wind would compete effectively in the IRP.

Q Please summarize your conclusions with respect to the renewable deficiency date in this case.

A PacifiCorp's proposed 2028 renewable deficiency date is inconsistent with the likely coal retirements that can be expected if PacifiCorp (a) abides by EPA's requirements to either retrofit or retire the Hunter and Huntington units, and (b) runs the System Optimizer model allowing coal units to retire endogenously (i.e., if not cost-effective). Based on the Company's proposed renewable energy proxy costs, I would expect that renewable energy, including Utah solar, would partially displace existing coal by 2022, well ahead of the 2028 date put forward by PacifiCorp. The Company's 2017 IRP affirms that new Wyoming wind is cost effective in 2021.

PacifiCorp's proposed 2028 renewable deficiency date is also inconsistent with the recent renewable RFP process, the results of which indicated that PacifiCorp would be deficient (i.e., would seek to procure RFP renewable energy) in 2018, at the proxy costs of renewable energy advocated by the Company in this case.

<u>Recommendations</u>

Q Please summarize your recommendations in this proceeding.

A I recommend that:

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[42] Docket No. LC 67, PacifiCorp's 2017 IRP at 214.

1. The Commission require PacifiCorp to set current Schedule 37 rates with an assumed 2021 non-renewable deficiency date.

2. The Commission require PacifiCorp to set current Schedule 37 rates with a renewable deficiency date between 2019 and 2022.

3. The Commission require PacifiCorp to re-run System Optimizer with its currently assessed renewable proxy prices (i.e., 2015 IRP Update), allowing the endogenous retirement of coal units, and not restricting transmission as held by individual coal units.

4. The Commission should consider changing its criteria for IRP updates to reflect that resource procurement schedules can change as a function of gas and electricity prices, as well as other inputs used by the Company—not only commodity prices.

Q Does this conclude your testimony?

A It does.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1794

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER's	)
Investigation into Schedule 37 - Avoided	)
Cost Purchases from Qualifying Facilities	)
of 10,000 kW or Less.	)
	)
	)

EXHIBIT REC-CREA/201

QUALIFICATIONS OF JEREMY FISHER

May 30, 2017

Jeremy Fisher, Ph.D., Principal Associate

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Cambridge MA. *Principal Associate*, 2013 – present, *Scientist*, 2007 – 2013.

Consulting on economic analysis of climate change and energy, carbon, and emissions policies. Quantitative evaluations of regional climate change impact, energy efficiency programs, long- and short-term electric industry planning, carbon reduction planning, and emissions compliance programs.

Tulane University, New Orleans, LA. *Ecology and Evolutionary Biology Postdoctoral Research Scientist*, 2006 –2007.

Determining Hurricane Katrina's impact on Gulf Coast ecosystems using satellite and field data.

University of New Hampshire, Durham, NH. *Earth, Oceans, and Space Postdoctoral Research Scientist*, 2006 –2007.

Organizing team synthesis review of causes and rates of natural rainforest loss in the Amazon basin.

Brown University Watson Institute for International Studies, Providence, RI. *Visiting Fellow*, 2007 – 2008.

Designing study to examine migratory bird response to climate variability in the Middle East.

Brown University Department of Geological Sciences, Providence, RI. *Research Assistant*, 2001 –2006.

Tracking impact of climate change on New England forests from satellites. Working with West African communities to determine impact of climate change and practice on landscape. Modeling coastal power plant effluent from satellite data.

EDUCATION

Brown University, Providence, RI
Doctor of Philosophy in Geological Sciences, 2006

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Master of Science in Geological Sciences, 2003

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FELLOWSHIPS & AWARDS

- *Visiting Fellow*, Watson Institute for International Studies, Brown University, 2007
- *Finalist*, Congressional Fellowship, American Institute of Physics and Geological Society of America, 2007
- *Fellow*, National Science Foundation East Asia Summer Institute (EASI), 2003
- *Fellow*, Henry Luce Foundation at the Watson Institute for International Studies, Brown University, 2003

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Wyoming Public Service Commission (Docket 2000-418-EA-12): Direct testimony regarding the application of PacifiCorp for approval of a certificate of public convenience and necessity to construct selective catalytic reduction systems on the Jim Bridger Units 3 and 4. On behalf of Sierra Club. February 1, 2013.

Public Service Commission of Wisconsin (Docket No. 6690-CE-197): Direct, rebuttal, and surrebuttal testimony regarding Wisconsin Public Service Corporation's application for authority to construct and place in operation a new multi-pollutant control technology system for Unit 3 of Weston Generating Station. On behalf of Clean Wisconsin. Direct testimony submitted November 15, 2012, rebuttal testimony submitted December 14, 2012, surrebuttal testimony submitted January 7, 2013.

Utah Public Service Commission (Docket 12-035-92): Direct, surrebuttal, and cross-answering testimony regarding Rocky Mountain Power's request for approval to construct Selective Catalytic Reduction systems at Jim Bridger units 3 and 4. On behalf of Sierra Club. November 30, 2012.

Oregon Public Utility Commission (Docket UE 246): Direct testimony in the matter of PacifiCorp's filing of revised tariff schedules for electric service in Oregon. On behalf of Sierra Club. June 20, 2012.

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Kentucky Public Service Commission (Dockets 2011-00161/2011-00162): Direct testimony regarding the application of Kentucky Utilities/Louisville Gas and Electric Company for certificates of public convenience and necessity and approval of its 2011 compliance plan for recovery by environmental surcharge. On behalf of Sierra Club and Natural Resources Defense Council (NRDC). September 16, 2011.

Kansas Corporation Commission (Docket 11-KCPE-581-PRE): Direct testimony in the matter of the petition of Kansas City Power & Light (KCP&L) for determination of the ratemaking principles and treatment that will apply to the recovery in rates of the cost to be incurred by KCP&L for certain electric generating facilities under K.S.A. 66-1239. On behalf of Sierra Club. June 3, 2011.

Utah Public Service Commission (Docket 10-035-124): Direct testimony in the matter of the application of Rocky Mountain Power for authority to increase its retail electric utility service rates in Utah and approval of its proposal electric service schedules and electric service regulations. On behalf of Sierra Club. May 26, 2011.

Wyoming Public Service Commission (Docket 20000-384-ER-10): Direct testimony in the matter of the application of Rocky Mountain Power for authority to increase its retail electric utility rates in Wyoming approximately $97.9 million per year or an average overall increase of 17.3 percent. On behalf of Powder River Basin Resource Council. April 11, 2011.

Resume dated May 2017

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1794

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER's	)
Investigation into Schedule 37 - Avoided	)
Cost Purchases from Qualifying Facilities	)
of 10,000 kW or Less.	)
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EXHIBIT REC-CREA/202

REVIEW OF THE USE OF THE SYSTEM OPTIMIZER MODEL IN PACIFICORP'S 2015 IRP

May 30, 2017

Review of the Use of the System Optimizer Model in PacifiCorp's 2015 IRP

Including treatment of the Clean Power Plan and economic coal plant retirement

Prepared for Sierra Club, Western Clean Energy Campaign, Powder River Basin Resource Council, Utah Clean Energy, and Idaho Conservation League

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EXECUTIVE SUMMARY

PacifiCorp utilized the System Optimizer model to conduct least-cost system planning in its 2015 IRP. Synapse reviewed this model, reviewed PacifiCorp's inputs and configuration choices, and conducted several sensitivity scenarios. The intent of these sensitivities was to allow the model to better optimize decisions in the face of planning constraints faced by PacifiCorp, and to demonstrate a more flexible and transparent approach. The Synapse runs considered endogenous retirements, a significant PacifiCorp omission, as well as alternative means of Clean Power Plan (CPP) compliance and renewable cost assumptions.

PacifiCorp chose to hard-code all power plant retirements into the System Optimizer model, based on an *a priori* determination of four Regional Haze compliant scenarios. While this approach ensured the model complied with Regional Haze, it severely limited the flexibility in finding a least-cost plan. The endogenous retirement sensitivity run by Synapse demonstrates clearly that the units chosen by PacifiCorp for retirement under the Preferred Portfolio are not necessarily the most economic units to retire under a more flexible approach. Hunter, Huntington, and Naughton all appeared potential candidates for retirement, but were not explored in PacifiCorp's IRP.

The Synapse team also implemented CPP compliance via a mass-based approach, a more transparent and easily optimized planning process than PacifiCorp's in-house 111(d) compliance tool. The PacifiCorp 111(d) tool required substantial manual manipulation by the IRP team at PacifiCorp, and ignored both the computational capability of the optimization tools built into System Optimizer, and largely discounted the value of using a capacity expansion tool in the first place. When Synapse adjusted the model to allow endogenous retirements, distinctly different trajectories and decisions were selected from PacifiCorp's Preferred Portfolio.

By forcing units to retire based on *a priori* assumptions, PacifiCorp's IRP development process violates basic principles of least-cost resource planning, and takes a major step backwards from progress made by PacifiCorp in its 2013 IRP. By effectively only modeling rate-based compliance with the CPP, PacifiCorp failed to seek a least-cost plan to meet customer requirements and emissions limits.

1. PacifiCorp's Implementation of Clean Power Plan and Coal Retirements in 2015 IRP

1.1 Clean Power Plan Implementation

PacifiCorp's 2015 IRP models a version of the Clean Power Plan (CPP) as proposed by EPA in 2014. Finalized in August 2015, the CPP is EPA's rule to meet CO_2 emissions limitations from existing sources after determining a Best System of Emissions Reductions (BSER). The proposed CPP, upon which the 2015 IRP is ostensibly based, allowed states to meet either mass-based emissions targets (measured in total tons of emissions), or rate-based emissions targets (measured pounds per megawatt-hour). In a rate-based compliance scenario, renewable energy and energy efficiency can "dilute" fossil emissions. PacifiCorp oriented its 2015 IRP around a single interpretation of the proposed CPP, using the dominant compliance mechanism—rate-based compliance for individual states—with the assumption that renewable energy and energy efficiency programs were fully fungible across states. This narrowness of focus left PacifiCorp in the position of structuring many of its assumptions and operational restrictions around this single expectation of the regulation, and does not comport with reasonable least-cost planning in the face of the uncertainty the Company faced at the time.

The proposed CPP set forth two basic routes for reducing state CO_2 emissions from existing sources: states could either meet the rate-based target using a combination of "building blocks"[1] or other programs, or meet an alternate mass-based target, measured in total tons of CO_2. EPA's proposal allowed states to choose the metric by which they measure compliance. The rate-based mechanism is a fairly unique measure of compliance, while the mass-based system is similar to the result of a cap-and-trade scheme, currently employed for national sulfur dioxide (SO_2) emissions under the Acid Rain Program, regionally for nitrogen oxides (NO_X) under a budget trading program, and for CO_2 in California and Regional Greenhouse Gas Initiative (RGGI) states. The rate-based approach, at least as used in EPA's target-setting in the proposed rule, assigned credit for renewable energy and energy efficiency programs implemented by entities in the state. The mass-based approach assigns credit for stack-based emissions reductions.

The rate-based compliance approach is, by all measures, far harder to model when optimizing for least-cost on a net present value basis. The mass-based approach is far simpler. Since at least the mid-1990s with the advent of SO_2 and NO_X trading programs, energy planners have understood that it was appropriate to model mass emissions caps using an opportunity cost for generators, regardless of whether emissions allowances were tradable. Every ton of emissions avoided by reducing generation eases compliance and thus has monetary value. In "hard cap" mass-emissions reduction modeling,

[1] EPA structured the proposed CPP around four fundamental "building blocks" that represented possible means for achieving the established emissions standard: (1) increasing existing coal plant efficiency, (2) displacing coal generation with existing natural gas, (3) increasing renewable energy acquisitions, and (4) implementing energy efficiency programs. Taken together, EPA estimated that these programs would reduce emissions by a certain amount in each state.

emissions have a shadow price—i.e., the cost of incrementally shifting production to lower emissions sources, on a per-ton basis. In a tradable credit program, the emissions have a direct monetary value, but the meaning is the same. In both cases, the cost of emissions is typically considered a variable cost—i.e., higher costs for high emissions resources should result in lower production.[2]

A rate-based trading mechanism is much more difficult to structure in capacity expansion models. Most off-the-shelf dispatch and capacity expansion models have not been structured to support this mechanism. Nonetheless, rate-based compliance is the mechanism that PacifiCorp has chosen to utilize in almost every one of the core cases in the 2015 IRP. PacifiCorp's System Optimizer model is <u>not</u> configured to determine a least-cost plan for rate-based compliance, but it is readily configured to determine a least-cost plan for mass-based compliance.

Out of the 15 "Core Cases" modeled by PacifiCorp, 12 assumed that PacifiCorp would comply on a rate basis. One assumed that PacifiCorp would not need to comply with the CPP at all, and just two assumed that PacifiCorp would comply on a mass basis. These two cases (C12 & C13) restricted the model from retiring coal units as a form of compliance, and thus cannot be representative of a possible least-cost plan to meet emissions targets.

To overcome the barrier that System Optimizer cannot search for a least-cost rate-based compliant plan, PacifiCorp fundamentally misused the model, manually choosing and excluding resources in order to meet targets in different states. PacifiCorp developed its separate in-house "111(d)" tool specifically to develop user-specified portfolios that meet rate-based compliance. This tool required the PacifiCorp IRP team to manually distribute and balance renewable energy and energy efficiency credits amongst states, check for unit operational violations, and choose buildout options manually, rather than allowing the model to choose least-cost options. By developing each individual portfolio manually, PacifiCorp undermined System Optimizer's ability to find least-cost plans. By choosing to model exclusively rate-based compliance, PacifiCorp hedged on one interpretation of EPA's proposed rule, and failed to evaluate if mass-based compliance with economic unit retirement could result in lower cost outcomes.

1.2 Final Clean Power Plan as Compared to Proposal

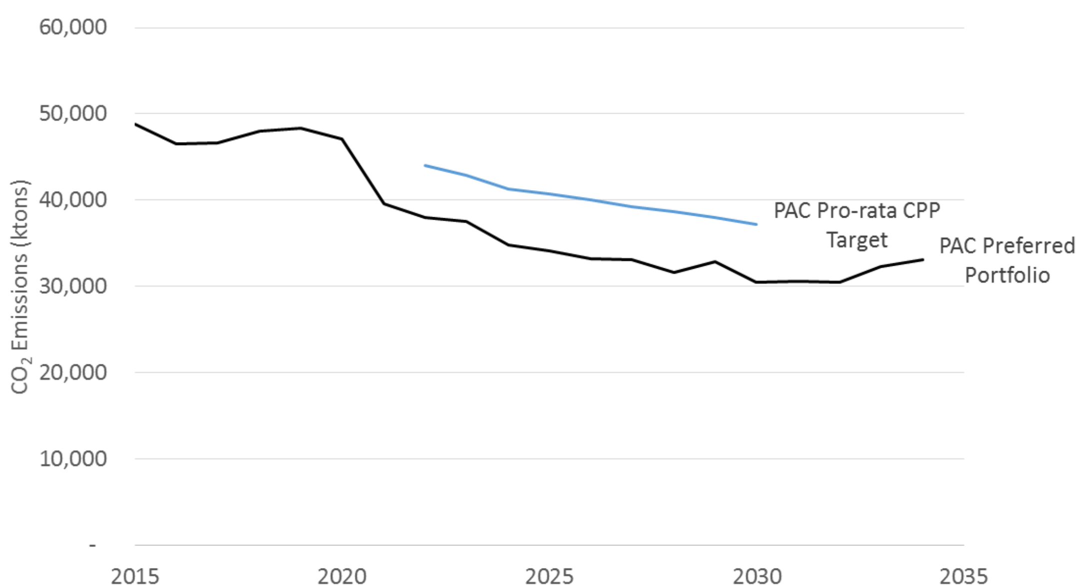
As regularly acknowledged by the PacifiCorp IRP team, during the development of the 2015 IRP, neither the Company nor stakeholders could know the final form of the CPP. As a result, PacifiCorp embarked on an ambitious and challenging plan to model the specifics of the rate-based proposed rule based on state-average emission rates. While this option remains as a compliance pathway in the final rule, the final rule eliminates the eligibility of the vast majority of renewable energy PacifiCorp uses to meet its compliance limitations in the IRP. The final rule also provides additional compliance pathways, including

[2] This mechanism is described in fair detail in a paper from Resources for the Future from 2008: Burtraw, D and D. Evans. 2008. Tradable Rights to Emit Air Pollution. Resources for the Future Discussion Paper. RFF DP 08-08

unit-specific emissions rates, alternative rates based on a weighted average state emission rate, and mass-based targets with and without new source complements (i.e., new fossil units).

While the PacifiCorp Preferred Portfolio appears to be compliant with the final mass-based goals, based on PacifiCorp's pro-rata share of emissions in Arizona, Colorado, Montana, Oregon, Utah, Washington, and Wyoming, (shown in 1.3 Why Mass-Based Compliance and Economic Coal Retirement Matters), it is by no means clear that the plan represents a least-cost pathway towards compliance.

Figure 1: PacifiCorp system-wide CO_2 emissions compared to mass-based target



1.3 Why Mass-Based Compliance and Economic Coal Retirement Matters

PacifiCorp's coal fleet has faced, and continues to face, a variety of new environmental regulations that impose costs and operating restrictions. Since 2008, PacifiCorp has engaged in significant capital and operating expenditures to comply with Regional Haze obligations and the Mercury and Air Toxics Standards (MATS) rule. Going forward, PacifiCorp's coal units will likely see costs for additional Regional Haze obligations, and may see impacts of National Ambient Air Quality Standards (NAAQS), as well as a coal combustion residual (CCR) rule, and CO_2 emissions costs from the Clean Power Plan.

This raises the question of whether PacifiCorp specifically avoided reviewing mass-based compliance and economic unit retirement not because it was too difficult to accomplish or because the model couldn't handle the inputs, but because this modeling would result in numerous coal unit retirements that are not strategically advantageous to PacifiCorp.

Why do economic coal unit retirements matter? Coal comprises about 50 percent of PacifiCorp's owned capacity, and nearly 70 percent of its generation. Even eliminating any new gas builds and taking into account expected near-term retirements, PacifiCorp has excess energy resources through at least 2024.[3] While the existing fleet remains, the system has very little headroom for new low-emissions, low-cost resources. Unless energy efficiency, renewable energy, and other low emissions resources have the opportunity to compete in a level playing field against PacifiCorp's existing fleet, we cannot know how much of a benefit ratepayers would find in a cleaner fleet.

In a 2011 Wyoming rate case,[4] Powder River Basin Resource Council argued that PacifiCorp had failed to appropriately evaluate if the retirement of Naughton 1 & 2 would be less expensive than installing expensive environmental retrofits at those units. As a result of the settlement emerging from that proceeding, PacifiCorp agreed to evaluate future environmental capital expenditures in litigated dockets. Shortly thereafter, PacifiCorp filed a Certificate for Public Convenience and Necessity (CPCN) for retrofits at Naughton 3. During that proceeding, intervenors discovered errors in PacifiCorp's analyses, and upon revising the model, PacifiCorp discovered that Naughton 3 could not be considered economically beneficial. In mid-2012, PacifiCorp withdrew its application, effectively proving that economic coal retirements mattered in decision-making.

In its 2011 IRP (March 2011), PacifiCorp effectively ignored impending environmental regulations for the purposes of the IRP, assuming that existing coal units would continue operations unabated. This IRP conducted a "proof-of-concept modeling of coal unit replacements,"[5] but disclosed little about the study or its specific results. The study was not used to inform the action plan or concurrent capital expenditures.

Around 2011, Ventyx (now ABB), the model vendor for System Optimizer, upgraded the ability of the capacity expansion model to allow for "endogenous" coal retirements. In other words, the model became capable of choosing if existing thermal units should be operated, retired, or changed (i.e., converted to natural gas), independent of user choice. This capacity had not been used by PacifiCorp in the 2011 IRP, but under regulatory pressure, PacifiCorp expanded the study in the 2011 IRP Update (March 2012) to review investments at Naughton, Jim Bridger, Hunter, Craig, and Hayden.[6] In this study, PacifiCorp reviewed the economics of retiring or retrofitting individual units. In addition, PacifiCorp began testing the model's ability to endogenously retire coal units.

PacifiCorp's IRP methodology peaked in 2013, when PacifiCorp significantly improved its transparency and logic.[7] In that IRP, low gas prices and high CO_2 prices led to the retirement of the vast majority of

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[3] Results from 2015 IRP, Core Case CO5a-3Q. 2015.

[4] 20000-384-ER-10

[5] Termed the "coal plant utilization study." 2011 IRP, p180

[6] 2011 IRP Update, p67.

[7] In the 2013 IRP, PacifiCorp expanded the endogenous retirement capability of System Optimizer. Each unit was allowed to continue operation, or retire or convert to natural gas. The same endogenous retirement capacity was then used by PacifiCorp to examine investments in individual coal units for the purposes of Certificates of Public Convenience and Necessity in Wyoming and Pre-Approvals in Utah.

PacifiCorp's fleet.[8] Stakeholders suggested that, following this IRP, various sensitivities should be evaluated to assess the economic robustness of the fleet. The IRP had raised questions about units that had not previously been considered economically vulnerable.

The 2015 IRP provided an opportunity to refine PacifiCorp's IRP methodology, and start an informed conversation about ratepayer costs and benefits towards transitioning to a cleaner fleet. PacifiCorp found an opportunity in the Clean Power Plan to circumnavigate this conversation and to decide, without explanation, which units they felt should be retired and over what timeframe. PacifiCorp completely eliminated the endogenous retirement capacity of System Optimizer in all but one core case (C14a). In the remainder of the IRP, PacifiCorp instead chooses a "Regional Haze Scenario" in which some units are retrofit and others are converted or retired early. In every case, PacifiCorp simply programs in the retirement schedule, denying the opportunity for the model to choose an optimal path under environmental constraints. This complete turnaround is a shortfall in the 2015 IRP, and represents a significant step backwards by the utility in finding a least-cost plan to meet environmental compliance requirements.

Allowing the model to choose to retire units optimally results in a lower cost plan than when retirements are guessed by planners. PacifiCorp confirms this outcome for the case in which a CO_2 cost is also imposed: "When allowing endogenous coal unit retirements beyond those assumed for Regional Haze scenarios (core case C14a), costs are lower than the C14 portfolios developed with specific timing for assumed coal unit retirements."[9] In the 2015 IRP, PacifiCorp removed the opportunity for ratepayers to evaluate one of the most important elements of their fleet and the singular, key decision of the IRP.

2. Overview of Synapse's Analysis

The Synapse team acquired System Optimizer to explore the impact of correcting the modeling deficiencies in PacifiCorp's IRP. We used the model to begin the process of constructing an optimized long-range resource plan, complete with economic coal unit retirements, mass-based CPP compliance,

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[8] From the 2013 IRP, p161: "Building upon modeling techniques developed in the 2011 IRP and 2011 IRP Update, environmental investments required to achieve compliance with known and prospective regulations at existing coal resources have been integrated into the portfolio modeling process for the 2013 IRP. Potential alternatives to environmental investments associated with known and prospective compliance obligations are considered in the development of all resource portfolios. Integrating potential environmental investment decisions into the portfolio development process allows each portfolio to reflect potential early retirement and resource replacement and/or natural gas conversion as alternatives to incremental environmental investment projects on a unit-by-unit basis. This advancement in analytical approach marks a significant evolution of the IRP process as it requires consideration of potential resource contraction while simultaneously analyzing alternative resource expansion plans."

[9] 2015 IRP, p210.

and with lower criteria emissions than the PacifiCorp plan. The assessment built upon the Company's 2015 IRP System Optimizer database with four incremental changes to the model:

- **Mass-Based CPP Approach** via implementation of an annual CO_2 price in $/ton;
- **Endogenous Coal Unit Retirements** by relaxing of constraints imposed by PacifiCorp on the model to prevent units from being retired;
- **Incorporation of Avoidable O&M** where major capital expenditures in the two years prior to retirement were assumed to be avoidable, and deducted from "decommissioning" costs; and
- **Lower Renewable Energy Costs** based on recent cost estimates, in order to test the sensitivity of new build options to costs.

We discuss these incremental changes in further detail below.

2.1 Mass-Based CPP Approach via Carbon Pricing

PacifiCorp's System Optimizer model is not configured to determine a least-cost plan for CPP rate-based compliance. As described above, a mass-based approach would be much simpler to model and fit into the existing construction of the System Optimizer framework without requiring so many opaque steps. A straightforward way to model a mass-based target is via a CO_2 price. The Synapse team used the Synapse Low CO_2 Price forecast—representative of a Clean Power Plan compliance structure that is relatively lenient—to incorporate the CPP compliance requirement in PacifiCorp's long-range resource planning.[10]

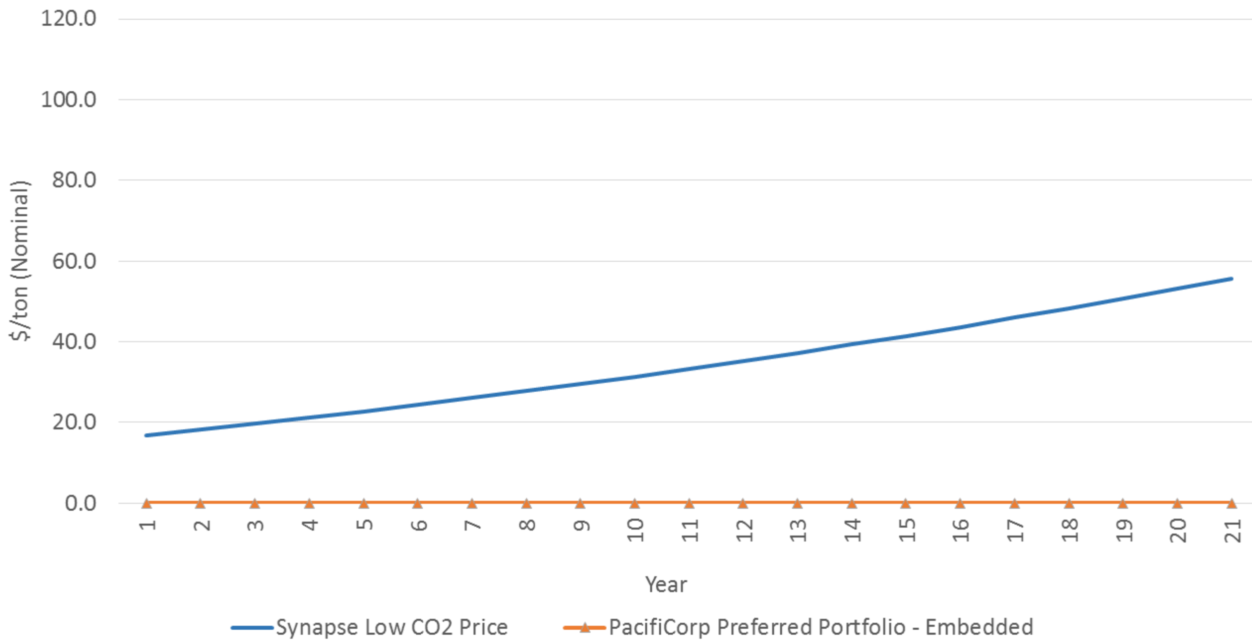
Figure 2 shows the Synapse Low CO_2 Price applied: from $16.7/ton in 2020[11] to approximately $41.4/ton in 2035 (nominal dollars). This is in comparison to the default Core 14a case price of $22/ton in 2020 rising to $76/ton by 2034. CO_2 prices in $/ton were modeled as a direct emissions cost at the unit-level, and translated into an equivalent $/MWh adder for market level transactions, including spot purchases and sales, and front office transactions (FOTs).[12]

[10] Luckow, P., E. A. Stanton, S. Fields, B. Biewald, S. Jackson, J. Fisher, R. Wilson. 2015. *2015 Carbon Dioxide Price Forecast*. Synapse Energy Economics.

[11] Modeling was performed prior to the release of the final Clean Power Plan rule, which moves compliance requirements to 2022.

[12] We assumed an incremental electricity price ($/MWh) adder to PacifiCorp's Preferred Portfolio market price, based on an implied tons CO_2/MWh from Core Case 14a (a case that *included* a carbon price) and Synapse's Low CO_2 price in $/tons CO_2.

Figure 2. Synapse CO_2 Low Price forecast



2.2 Endogenous Coal Unit Retirement

As noted above, in the 2015 IRP, PacifiCorp also completely eliminated the endogenous retirement capacity of System Optimizer in all but one core case (C14a), in which it allowed five coal units to be endogenously retired.[13] The Synapse team built upon this case, and the straightforward mass-based CPP compliance implementation described above, to enable the model to choose investments and retirements at all plants in 2020 and beyond.

Results for generation capacity and coal unit retirements, summarized below in

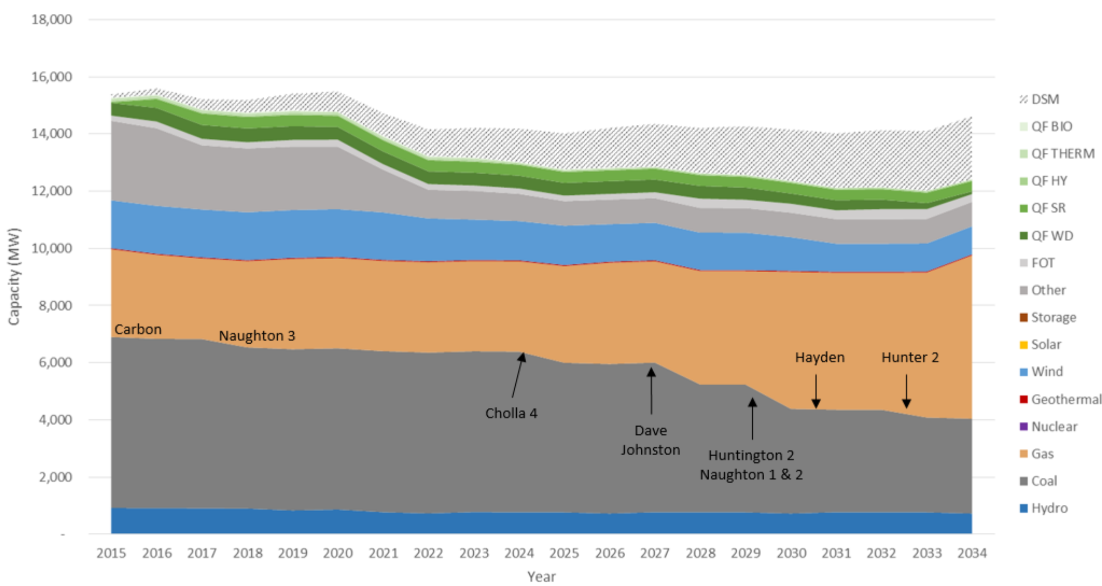
Figure 3, show that System Optimizer chooses a drastically different coal unit retirement schedule when allowed to choose retirements based on costs. The effect of allowing System Optimizer to find a least-cost resource plan by *choosing* which units to retire and build rather than *telling* it which units to retire and build, under a straightforward mass-based CPP compliance pathway, retires units earlier—beginning in 2020 with Hayden 1 & 2 and Craig 1, and followed by the retirement of Hunter 1, Naughton 2 and Cholla 4 in 2021, and Hunter 2 in 2022.

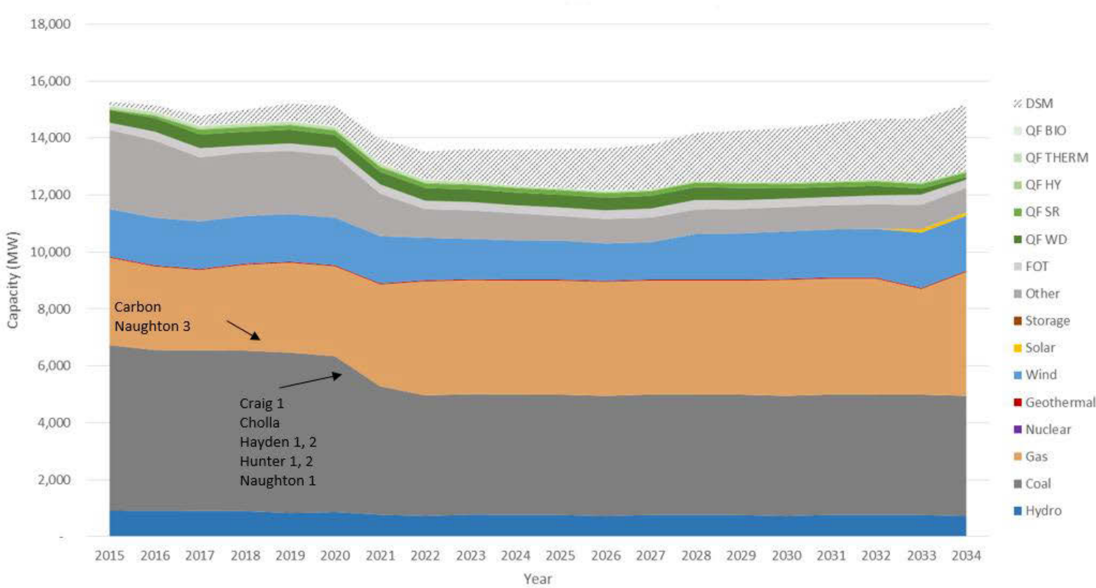
This is important because Hunter and Naughton are not identified in any of PacifiCorp's Regional Haze scenarios as potential near-term retirements, yet they are clearly marginal units in this analysis. Hayden,

[13] C14a only allowed Hunter 1 & 3, Bridger 3 & 4, and Wyodak to be retired endogenously.

Craig, and Cholla are all the subject of recent PacifiCorp assessments and are similarly removed from consideration in the Core Cases of the 2015 IRP.

Figure 3. Generation capacity by year: PacifiCorp Preferred Portfolio (top) and Alternative IRP with 1) endogenous retirements and 2) mass-based CPP compliance (low CO_2 price)





Source: Synapse analysis.

2.3 Adjustment to Decommissioning Costs to Capture Avoidable O&M

Sound least-cost utility resource planning should appropriately avoid major capital expenditures immediately before a retirement. The decommissioning costs PacifiCorp included in its 2015 IRP include both the costs to actually retire and dismantle the plant, as well as recovery of any stranded costs incurred during the analysis period. For example, incurring a capital expense in one year entails a de-facto hurdle to retire the next year, because the model assumes that stranded capital investments are moved into a regulatory asset and recovered in full. Aside from the open question of if PacifiCorp can or should assume that stranded costs are recoverable for retiring units (or should be considered a forward-going cost), the assumption makes little sense in context of logical forward planning. In the years leading up to a unit's phase-out, it would not be reasonable to incur many major capital expenditures. Why invest in life extension measures for a unit that has only a few years of life remaining?

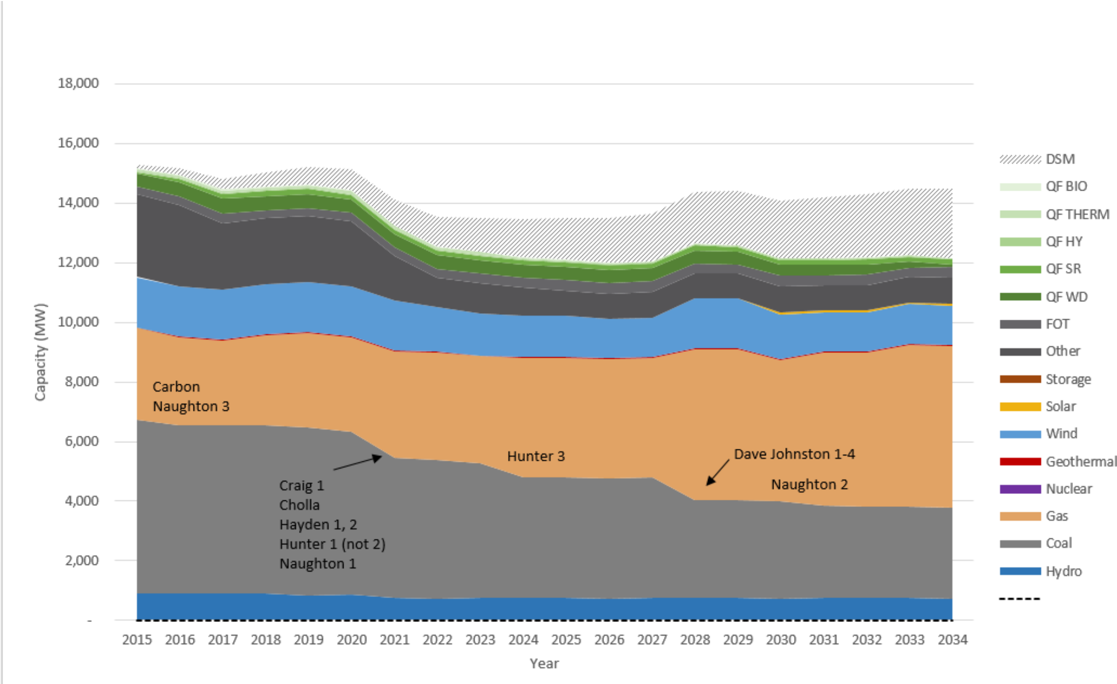
To account for this reality, the Synapse team added a third cost term to the total decommissioning cost of a unit: avoidable fixed O&M and run rate capital. We assume that in the two years prior to a unit going offline, retirement is known and major capital expenditures can be avoided. Ongoing fixed O&M expenses are still incurred (although major outages are avoided), as are known and potential future requirements for SCRs on most units (Synapse's endogenous retirement case assumes Reference Regional Haze assumptions of the IRP).[14]

By adjusting the decommissioning costs in this manner, we continue to assume that PacifiCorp recovers stranded investments in existing units when they retire, but allow unit retirements to be primarily driven by their economics. These units can now be used to contribute towards compliance requirements, if it is least-cost to do so, in a way that is more consistent with the System Optimizer framework than PacifiCorp's in-house tool. We assume the Dave Johnston units 1-4 retire at the end of their book life in this case, as well, to establish consistency with realistic expectations about this plant's operational usefulness in the existing portfolio at 2027. Other units that reach the end of their economic life after 2027 are not forced into retirement.

As shown in Figure 4, below, this adjustment advances the retirement of Hunter 2 by one year, to 2021.

[14] Due to time and expense limitations, Synapse made the simplifying assumption that capital expenditures two years prior to retirement could be avoided, but not expenses in earlier years. A more advanced version of this might include evaluating the merits of specific capital expenditures relative to the timing of the retirement decision.

Figure 4. Generation capacity by year: Alternative IRP with 1) endogenous retirements, 2) mass-based CPP compliance (low CO_2 price), and 3) adjusted decommissioning costs



2.4 Lower Renewable Energy Costs

The capital costs for renewable energy, specifically wind and solar, in PacifiCorp's System Optimizer model are not indicative of commonly held costs for these technologies. PacifiCorp includes a range for new wind builds at $2135-$2188/kW and new solar builds at $2546-$2829/kW (see Table 1). In addition, there is no new wind added to PacifiCorp's system in its 2015 IRP, and very little solar (7 MW in Oregon in 2016). The combination of these two facts calls into question whether new renewable energy is being excluded from the Company's IRP due to its high costs. To test this hypothesis, Synapse modeled alternative capital costs for both new wind and solar technologies, as recommended by Utah Clean Energy (UCE).

Table 1. Alternative wind and solar resource capital

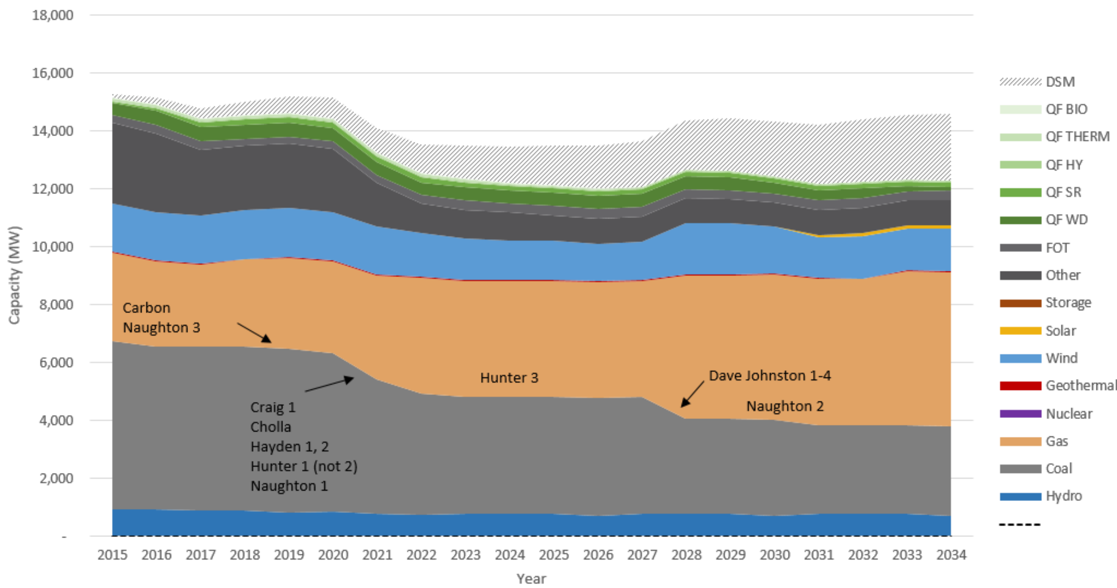
PacifiCorp's (PAC) Resource Assumptions (IRP Table 6.1)	Capacity	PAC's Capital Cost	UCE Recommended Capital Cost [1,2]
Wind			
2.0 MW turbine 29% CF WA/OR	100 MW	$2,135/kW	$1,747/kW
2.0 MW turbine 31% CF UT/ID	100 MW	$2,188/kW	$1,800/kW
2.0 MW turbine 43% CF WY	100 MW	$2,156/kW	$1,768/kW
Solar			
PV Poly-Si Fixed Tilt 26.5% CF	50.4 MW	$2,546/kW	$1,717/kW
PV Poly-Si Single Tracking 31.6% CF	50.4 MW	$2,702.kW	$1,873/kW
PV Poly-Si Fixed Tilt 25.4% CF	50.4 MW	$2,659/kW	$1,830/kW
PV Poly-Si Single Tracking 29.2% CF	50.4 MW	$2,829/kW	$2,000/kW

[1] *Wind values are based on US DOE Wind Vision Report, Chapter 2, pages 12-13, available at: http://www.energy.gov/sites/prod/files/wv_chapter2_wind_power_in_the_united_states.pdf.*
[2] *Solar values are based on IHS Outlook for US Solar PV Capital Costs and Prices, 2014–2030 / October 2014.*

To test the impact of the updated renewable energy costs, Synapse applied the costs provided by UCE as incrementally lower $/kW costs to a modified version of the case described above, with endogenous retirements, mass-based CPP compliance through a low CO_2 price, improved decommissioning costs, and assumed phase-out of the Dave Johnston plant in 2028. Applying the improved renewable energy costs to the previous case with a forced retirement of the Dave Johnston units (1-4) in 2028 was important: new wind farm opportunities are possible and economic at the Dave Johnston brownfield site. The case Synapse models continues to select no new renewable energy until either Dave Johnston retirement is forced or new transmission is added.

Overall, improved renewable energy costs do not untangle the layers of constraints PacifiCorp has included in its application of System Optimizer for its IRP. Even highly economic wind and solar fails to replace even new gas and existing coal (see Figure 5), suggesting that there are additional constraints beyond those identified here. Results show that under the current underlying structure of PacifiCorp's System Optimizer model, Wyoming is represented as highly transmission constrained between all nodes, and from Wyoming to Utah and Idaho. It is unclear if this constraint alone limits new renewable additions.

Figure 5. Generation capacity by year: Alternative IRP with 1) endogenous retirements, 2) mass-based CPP compliance (low CO_2 price), 3) adjusted decommissioning costs, 4) improved wind and solar capital cost assumptions, and 5) forced Dave Johnston 1-4 retirement in 2028



3. Constraints in the System Optimizer Model

System Optimizer is a highly complex modeling structure that allows extensive flexibility, yet also allows layers of constraints to dictate outcomes. PacifiCorp's use of the System Optimizer model layers in multiple overlapping constraints, some of which are not readily apparent. The model generally allows users to modify the model through scenarios, which have a different meaning in the System Optimizer framework than in common IRP parlance. Scenarios in the System Optimizer model are specific tweaks that cover any form of change in the model, from costs to transmission options, buildout constraints, or operational constraints.

To create an IRP scenario (i.e., 5a-3Q, the Preferred Portfolio), PacifiCorp layered nearly 20 scenarios covering transmission changes, market price changes, Regional Haze scenarios, CPP compliance options, system updates, and various other constraints in the system. These scenarios may (and often do) overlap and negate each other, making it difficult to track at any given time the series of constraints that may either prevent or require specific units to be built or retire. For example, PacifiCorp applies a number of "technology groups" to various scenarios, which individually limit cumulative and annual wind and solar buildout. These are overlaid with other scenarios that also limit or eliminate completely buildout options. Scenarios that eliminate or limit transmission are layered with scenarios that change when units are retired, and scenarios that impart (or remove) emissions costs. Ultimately, modifying PacifiCorp's System Optimizer model requires significant knowledge of the model, a detailed mapping of the scenarios and their meaning, and significant time. It is feasible, or likely, that in our short engagement, we did not find all of the relevant constraints that prevented the System Optimizer model from creating a reasonable buildout.

4. SUMMARY RESULTS

We summarize total costs and emissions for each of the cases explored by Synapse, and compare them to the Company's Preferred Portfolio. In the tables below, the cases are identified as:

A) Endogenous Retirements + Low CO_2 Price (Mass-based CPP Compliance) (**Section 2.2**),

B) Endogenous Retirements + Low CO_2 Price (Mass-based CPP Compliance) + Improved Decommissioning Costs + DJ 1-4 Retires 2028 (**Section 2.3**), and

C) Endogenous Retirements + Low CO_2 Price (Mass-based CPP Compliance) + Improved Decommissioning Costs + DJ 1-4 Retires 2028 + Utah Clean Energy Recommended Renewable Costs (**Section 2.3**).

These cases correspond to the sub-sections in Chapter 2, as noted. All of the cases considered reduced emissions below the PacifiCorp Preferred Portfolio. While CO_2 emissions in the Preferred Portfolio itself are likely compliant with the final Clean Power Plan targets, it is likely that over-compliance will generate credits that could be sold to other parties, within the states in which PacifiCorp operates or beyond. Therefore, the correct CO_2 price is one that correctly represents regional compliance, and not necessarily the one that produces the exact mass reductions required by PacifiCorp alone.

The Synapse team used the Reference Case Regional Haze scenario, a conservative emissions scenario designed to reach compliance with possible Regional Haze requirements, assuming that EPA federal plans are rigorous (i.e., assuming that PacifiCorp does not prevail in litigation loosening the requirements). The resulting state-by-state NOx and SO_2 emissions are well below the Preferred Portfolio, and serve to demonstrate that the Synapse scenarios are also likely to be compliant with Regional Haze requirements.[15]

[15] PacifiCorp did not implement changes in NOx and SO_2 emissions rates associated with the various Regional Haze Scenarios, and thus the SO model does not track NOx and SO_2 emissions correctly. Thus, to generate state-by-state NOx and SO_2 emissions, we mapped unit-specific heat input SO results to unit-specific NOx and SO2 emissions rates from PacifiCorp-provided workpapers.

Table 2. Summary of emissions in PacifiCorp Preferred Portfolio and Synapse cases (2015-2034)

Emissions	PAC Preferred	Case A	Case B	Case C
Total CO_2 (Mt)	878	865	832	826
Total NOx (Kt)	551	552	515	514
Total SO_2 (Kt)	546	500	491	486

In reporting costs, we have included the PVRR both with and without the costs of CO_2 allowance purchases. The logic in doing so is that CO_2 pricing could be simply an internal dispatch adder that PacifiCorp uses to adjust dispatch, without actually incurring costs to consumers. Similarly, CO_2 revenues could be returned directly back to customers in rebates, or used (as in RGGI) to offset energy efficiency or renewable energy programs, thus effectively remaining "inside" the system. Either way, we see these largely as transfer payments that would not be reflected in the overall system costs.

A large part of the differences in costs between the Synapse scenarios and the PacifiCorp Preferred Portfolio is the assumption of Reference Case Regional Haze assumptions. This case is a conservative case with regards to compliance, and installs SCR's on five more units than assumed under Regional Haze 3, the assumptions used in the Preferred Portfolio. Overall, the Reference Case has over $730 million (NPV) of capital costs that are not incurred in Regional Haze Scenario 1, but accomplishes significantly deeper reductions.

Table 3. Summary of costs in PacifiCorp Preferred Portfolio and Synapse cases

Costs (M$ NPV)	PAC Preferred	Case A	Case B	Case C
PVRR (2015-2034)	$28,095	$36,233	$36,363	$36,323
PVRR (CO_2 cost excluded)	$28,095	$28,137	$28,678	$28,720
Difference from PAC Pref.		$42	$541	$583

5. Discussion and Conclusions

The Synapse System Optimizer analysis considered a number of improvements to allow the model to better optimize decisions in the face of planning constraints faced by PacifiCorp. Our runs considered endogenous retirements, a major PacifiCorp omission, as well as alternative means of CPP compliance and sensitivity to renewable cost assumptions.

The endogenous retirement sensitivity demonstrated clearly that the units chosen by PacifiCorp for retirement under the Preferred Portfolio are not necessarily the most economic units to retire under a more flexible approach. Hunter, Huntington, and Naughton all appeared potential candidates for retirement, but were not explored in the PacifiCorp's IRP.

Implementing Clean Power Plan compliance via a mass-based approach proved to be a more transparent and easily optimized planning process than PacifiCorp's in-house compliance tool. When coupled with endogenous retirements, this resulted in distinctly different retirement trajectories than PacifiCorp's Preferred Portfolio. While both the Preferred and Alternative Plans appear to be compliant with the final rule, allowing more flexibility allows a broader array of planning decisions and uses the model as it was designed for: to find least-cost planning solutions.

By forcing units to retire based on *a priori* assumptions, PacifiCorp's IRP development process violates basic principles of least cost resource planning, and represents a major step backwards from the significant progress made by PacifiCorp in its 2013 IRP.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1794

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Cost Purchases from Qualifying Facilities	)
of 10,000 kW or Less.	)
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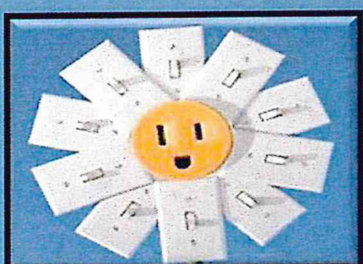
EXHIBIT REC-CREA/203

EXCERPT FROM 2015 IRP PUBLIC INPUT MEETING 3

May 30, 2017



2015 Integrated Resource Plan

Public Input Meeting 3

August 7-8, 2014

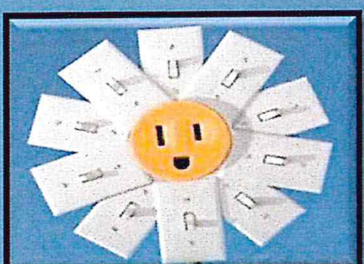
PACIFICORP
Rocky Mountain Power
Pacific Power
PacifiCorp Energy

Agenda

Day 1
- Introductions
- Supply-Side Resources
  - Includes Energy Storage Study
- *Lunch Break (1/2 hour) 11:30 PT/12:30 MT*
- Needs Assessment
- Distributed Generation Study
- Plant Efficiency Study

Day 2
- Portfolio Development
- Wind Integration
- *Lunch Break (1/2 hour) 11:30 PT/12:30 MT*
- Planning Reserve Margin
- Wind & Solar Capacity Contribution

August 26 Conference Call



2015 Integrated Resource Plan

Portfolio Development Sensitivity Analysis

PACIFICORP
Rocky Mountain Power
Pacific Power
PacifiCorp Energy

Regional Haze Scenarios

Reference Scenario (Stringent Regional Haze)

- Forced installation of controls for known, reasonably expected, and hypothetical stringent Regional Haze compliance obligations where agency action has not yet been taken; utilizes current depreciable life when shutdown is modeled as alternate compliance approach

Scenario RH-1

- Fleet-trade & inter-temporal scenario reflecting potential negotiated outcomes across the fleet; agency/regulator/litigant/joint owner perspectives on acceptability have not been determined

Scenario RH-2

- Fleet-trade & inter-temporal scenario reflecting potential negotiated outcomes across the fleet falling somewhere between the Reference Scenario and Scenario RH-1; agency/regulator/litigant/joint owner perspectives on acceptability have not been determined

Underlying Assumptions

- Fleet-trade & inter-temporal scenarios attempt to provide alternative environmental benefits that would be viewed as reasonable compliance alternatives by agencies and consider remaining depreciable life of assets, where practical

- Fleet-trade & inter-temporal scenarios consider alignment with future Regional Haze planning periods and anticipated compliance deadlines for other emerging environmental regulations where information is reasonably available

- Fleet-trade & inter-temporal scenarios attempt to recognize existing long-term commitments, ownership structures, and current environmental compliance position of individual units/facilities where those inputs would impact economic assessment of alternatives

- Fleet-trade & inter-temporal scenarios are intended to provide insight into potential alternate compliance approaches that may best serve customers while also addressing environmental compliance obligations; agency/regulator/litigant/joint owner perspectives on acceptability have not been determined nor are final outcomes expected to directly align with the scenarios assessed

Regional Haze Scenarios: Reference (C01-R)

Coal Unit	Description	Coal Unit	Description
Carbon 1	Shut Down Apr 2015	Hunter 1	SCR by Dec 2021
Carbon 2	Shut Down Apr 2015	Hunter 2	SCR by Dec 2021
Cholla 4	SCR by Dec 2017	Hunter 3	SCR by Dec 2024
Colstrip 3	SCR by Dec 2023	Huntington 1	SCR by Dec 2022
Colstrip 4	SCR by Dec 2022	Huntington 2	SCR by Dec 2022
Craig 1	SCR by Aug 2021	Jim Bridger 1	SCR by Dec 2022
Craig 2	SCR by Jan 2018	Jim Bridger 2	SCR by Dec 2021
Dave Johnston 1	Shut Down Dec 2027	Jim Bridger 3	SCR by Dec 2015
Dave Johnston 2	Shut Down Dec 2027	Jim Bridger 4	SCR by Dec 2016
Dave Johnston 3	SCR by Mar 2019, Shut Down Dec 2027	Naughton 1	Shut Down by Dec 2029
Dave Johnston 4	Shut Down Dec 2027	Naughton 2	Shut Down by Dec 2029
Hayden 1	SCR by Jun 2015	Naughton 3	Conversion by Jun 2018; Shut Down by Dec 2029
Hayden 2	SCR by Jun 2016	Wyodak	SCR by Mar 2019

Regional Haze Scenarios: RH-1

Coal Unit	Description	Coal Unit	Description
Carbon 1	Shut Down Apr 2015	Hunter 1	SCR by Dec 2021
Carbon 2	Shut Down Apr 2015	Hunter 2	Shut Down by Dec 2032
Cholla 4	Conversion by Jun 2029	Hunter 3	SCR by Dec 2024
Colstrip 3	SCR by Dec 2023	Huntington 1	Shut Down by Dec 2036
Colstrip 4	SCR by Dec 2022	Huntington 2	Shut Down by Dec 2021
Craig 1	SCR by Aug 2021	Jim Bridger 1	Shut Down by Dec 2023
Craig 2	SCR by Jan 2018	Jim Bridger 2	Shut Down by Dec 2032
Dave Johnston 1	Shut Down Mar 2019	Jim Bridger 3	SCR by Dec 2015
Dave Johnston 2	Shut Down Dec 2027	Jim Bridger 4	SCR by Dec 2016
Dave Johnston 3	Shut Down Dec 2027	Naughton 1	Shut Down by Dec 2029
Dave Johnston 4	Shut Down Dec 2032	Naughton 2	Shut Down by Dec 2029
Hayden 1	SCR by Jun 2015	Naughton 3	Conversion by Jun 2018; Shut Down by Dec 2029
Hayden 2	SCR by Jun 2016	Wyodak	Shut Down by Dec 2039

Regional Haze Scenarios: RH-2

Coal Unit	Description	Coal Unit	Description
Carbon 1	Shut Down Apr 2015	Hunter 1	SCR by Dec 2021
Carbon 2	Shut Down Apr 2015	Hunter 2	Shut Down by Dec 2024
Cholla 4	Conversion by Jun 2025	Hunter 3	SCR by Dec 2024
Colstrip 3	SCR by Dec 2023	Huntington 1	Shut Down by Dec 2024
Colstrip 4	SCR by Dec 2022	Huntington 2	Shut Down by Dec 2021
Craig 1	SCR by Aug 2021	Jim Bridger 1	Shut Down by Dec 2023
Craig 2	SCR by Jan 2018	Jim Bridger 2	Shut Down by Dec 2028
Dave Johnston 1	Shut Down Mar 2019	Jim Bridger 3	SCR by Dec 2015
Dave Johnston 2	Shut Down Dec 2023	Jim Bridger 4	SCR by Dec 2016
Dave Johnston 3	Shut Down Dec 2027	Naughton 1	Shut Down by Dec 2029
Dave Johnston 4	Shut Down Dec 2032	Naughton 2	Shut Down by Dec 2029
Hayden 1	SCR by Jun 2015	Naughton 3	Conversion by Jun 2018; Shut Down by Dec 2029
Hayden 2	SCR by Jun 2016	Wyodak	Shut Down by Dec 2032

BEFORE THE PUBLIC UTILITY COMMISSION

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Cost Purchases from Qualifying Facilities	)
of 10,000 kW or Less.	)
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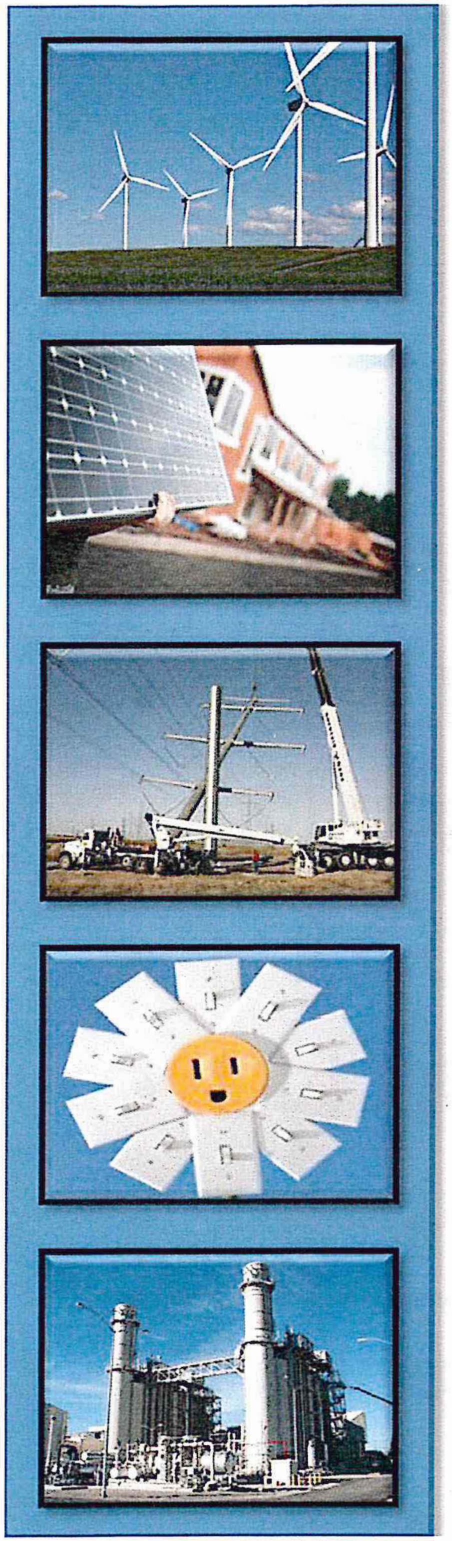
EXHIBIT REC-CREA/204

EXCERPT FROM 2015 IRP PUBLIC INPUT MEETING 5

May 30, 2017



2015 Integrated Resource Plan

Public Input Meeting 5
November 14, 2014

PACIFICORP
Rocky Mountain Power
Pacific Power
PacifiCorp Energy

Agenda

- Introductions
- EIM Update
- Price Curve Scenarios
- Portfolio Development Draft Results
- *Lunch Break (1/2 hour) 11:30 PT/12:30 MT*
- Portfolio Development Draft Results

Portfolio Development Update

- 50 System Optimizer runs required to develop 30 resource portfolios.
- Draft results have been completed for each core case.
  - Completed cases meet assumed 111(d) compliance obligations and state RPS compliance obligations, as applicable.
  - Completed cases reflect estimated costs for new resource transmission integration costs and transmission reinforcement costs, as applicable.

- Core Case Fact Sheets (handout)
  - Documents key input assumptions for each case.
  - Documents draft results for each case (*New!*).
    - PVRR System Costs
    - Resource Portfolio Summary
    - System CO_2 Emissions
    - 111(d) Compliance Profile, as applicable
  - Notice will be sent via the IRP Mailbox when spreadsheet results are posted to the IRP website.

Core Case Definitions

Case	111(d) Rule	111(d) Compliance Priority	CO_2 Price	FOTs	Price Curve
C01	None	None	None	Base	Base/No 111(d)
C02	All States, Emis. Rate	Re-dispatch + Base EE	None	Base	Sep 2014 OFPC
C03	All States, Emis. Rate	Re-dispatch + Inc. EE	None	Base	Sep 2014 OFPC
C04	All States, Emis. Rate	Renewable + Inc. EE	None	Base	Sep 2014 OFPC
C05	Retail States, Emis. Rate	Re-dispatch + Base EE	None	Base	Sep 2014 OFPC
C05a	Retail States, Emis. Rate	Re-dispatch + Base EE	None	Base	Sep 2014 OFPC
C06	Retail States, Emis. Rate	Re-dispatch + Inc. EE	None	Base	Sep 2014 OFPC
C07	Retail States, Emis. Rate	Re-dispatch + Inc. EE	None	Base	Sep 2014 OFPC
C09	Retail States, Emis. Rate	Re-dispatch + Base EE	None	Limited	Sep 2014 OFPC
C11	Retail States, Emis. Rate	Re-dispatch + Acc. EE	None	Base	Sep 2014 OFPC
C12	Mass Cap, New+Existing	None	None	Base	Sep 2014 OFPC
C13	Mass Cap, Existing	None	None	Base	Sep 2014 OFPC
C14	Retail States, Emis. Rate	Re-dispatch + Base EE	Yes	Base	Base/CO2 Adjusted
C14a	Retail States Emis. Rate	Re-dispatch + Base EE	Yes	Base	Base/CO2 Adjusted

- Cases C01 and C05a are replicated among three different Regional Haze Scenarios.
- All other cases are replicated among two different Regional Haze Scenarios.

Case Definition Updates

- Cases C05 through C07
  - No longer assume physical allocation of renewable resources by state boundary (not likely).
  - A key 111(d) uncertainty is how states might address fossil generation that does not serve retail load in the state, and the Company continues to engage with parties in these states to identify acceptable 111(d) compliance plans (i.e. reflecting PacifiCorp's plans to stop operating Cholla Unit 4 as a coal-fired asset by the end of 2024).
  - Consequently, cases C05 through C07 are defined as variants of cases C02 through C04 by removing Arizona, Colorado, and Montana from PacifiCorp's 111(d) compliance solution.
  - Cases C02 through C04 will inform PacifiCorp's 2015 IRP acquisition path analysis and continued discussions with stakeholders in these states.

- Cases C08 and C10 were eliminated (both assumed physical allocation of renewable resources by state boundary).

- Cases C09 (constrained FOTs) and C11 (accelerated DSM) are aligned with 111(d) assumptions per Case C05.

- Based on stakeholder feedback, Case C13 was added (note, the previous Case C13 has been renamed as Case C14) to provide a second mass cap case applicable to only existing fossil resources.

- Added alternatives to Cases C05 and C14
  - Cases C05a-1 and C05a-2 were added to analyze an Oregon unbundled REC RPS compliance strategy.
  - Upon reviewing Regional Haze retirement assumptions on the timing of new resources, Case C05a-3 was added to replicate the Oregon RPS unbundled REC strategy with alternative coal retirement assumptions.
  - Case C14a replicates Case C14, but allows endogenous retirement of coal units not already assumed to have an early retirement date under the applicable Regional Haze Scenario.

Regional Haze Scenarios

Coal Unit	Reference	RH-1	RH-2	RH-3
Dave Johnston 1	Shut Down Dec 2027	Shut Down Mar 2019	Shut Down Mar 2019	Shut Down Dec 2027
Dave Johnston 2	Shut Down Dec 2027	Shut Down Dec 2027	Shut Down Dec 2023	Shut Down Dec 2027
Dave Johnston 3	SCR by Mar 2019; Shut Down Dec 2027	Shut Down Dec 2027	Shut Down Dec 2027	Shut Down Dec 2027
Dave Johnston 4	Shut Down Dec 2027	Shut Down Dec 2032	Shut Down Dec 2032	Shut Down Dec 2027
Hunter 2	SCR by Dec 2021	Shut Down by Dec 2032	Shut Down by Dec 2024	Shut Down by Dec 2032
Huntington 1	SCR by Dec 2022	Shut Down by Dec 2036	Shut Down by Dec 2024	SCR by Dec 2022
Huntington 2	SCR by Dec 2022	Shut Down by Dec 2021	Shut Down by Dec 2021	Shut Down by Dec 2029
Jim Bridger 1	SCR by Dec 2022	Shut Down by Dec 2023	Shut Down by Dec 2023	SCR by Dec 2022
Jim Bridger 2	SCR by Dec 2021	Shut Down by Dec 2032	Shut Down by Dec 2028	SCR by Dec 2021
Wyodak	SCR by Mar 2019	Shut Down by Dec 2039	Shut Down by Dec 2032	Shut Down by Dec 2039

Common to All Scenarios:
Carbon 1&2 shutdown 2015; Cholla 4 gas conversion 2025; Colstrip 3&4 SCR 2023/2022, respectively; Craig 1&2 SCR 2021/2018, respectively; Hayden 1&2 SCR 2015/2016, respectively; Naughton 1&2 shutdown 2029; Naughton 3 gas conversion 2018, shutdown 2029; Hunter 1&3 SCR 2021/2024, respectively; and Bridger 3&4 SCR 2015/2016, respectively

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OF OREGON

UM 1794

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PACIFICORP, dba PACIFIC POWER's	)
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of 10,000 kW or Less.	)
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EXHIBIT REC-CREA/205

SIERRA CLUB DATA REQUEST 1.4
IN OREGON DOCKET LC-62, 2015 IRP

May 30, 2017

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

April 23, 2015

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Jeremy Fisher
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RE: OR Docket No. LC 62
Sierra Club 1st Set Data Request (1.1-1.9)

Please find enclosed PacifiCorp's Responses to Sierra Club 1st Set Data Requests 1.1-1.9. Provided electronically are Attachments Sierra Club 1.2, 1.5, and 1.7-2. Provided on the enclosed Confidential CD are Confidential Attachments Sierra Club 1.5 and 1.7-1. The confidential attachment is designated as confidential under Order No. 14-416 and may only be disclosed to qualified persons as defined in that order. Provided on a separate Confidential CD to Sierra Club only is Confidential Ventyx Attachment Sierra Club 1.8. This confidential attachment is provided subject to the terms and conditions of the applicable Ventyx mutual confidentiality agreement and is being provided to the requesting party only.

If you have any questions, please call me at (503) 813-6583.

Sincerely,

Natasha Siores/lm

Natasha Siores
Director, Regulatory Affairs & Revenue Requirement

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LC 62/PacifiCorp
April 23, 2015
Sierra Club Data Request 1.4

Sierra Club Data Request 1.4

Please refer to Table 7.2 (page 148) of the PacifiCorp 2015 IRP, Volume I. For each of the 10 units shown here:

a. Please explain why the Company assumed the SCR dates shown in column "Reference."
b. Please explain why the Company assumed the "shut down" dates shown in column "Reference."
c. Please explain why the Company assumed the "shut down" dates shown in column "Scenario 1."
d. Please explain why the Company assumed the "shut down" dates shown in column "Scenario 1."
e. Please explain why the Company assumed the SCR dates shown in column "Scenario 2."
f. Please explain why the Company assumed the "shut down" dates shown in column "Scenario 2."
g. Please explain why the Company assumed the SCR dates shown in column "Scenario 3."
h. Please explain why the Company assumed the "shut down" dates shown in column "Scenario 3."

Response to Sierra Club Data Request 1.4

As stated on page 148 of PacifiCorp's 2015 IRP, Volume I, the Regional Haze scenarios reflected in Table 7.2 were built around both known and prospective Regional Haze compliance requirements for the purpose of analyzing potential Regional Haze compliance scenarios. While PacifiCorp cannot speak for the state of Utah, the state of Wyoming, nor the United States (U.S.) Environmental Protection Agency (EPA) regarding intended future Regional Haze actions, PacifiCorp developed the hypothetical Regional Haze compliance alternative cases reflected in Table 7.2 based primarily upon PacifiCorp's general understanding of past state and federal Regional Haze rulemaking actions and timelines realized across the industry, with consideration given to the potential legal proceedings that may follow. PacifiCorp's hypothetical Regional Haze compliance alternative cases developed will prove informative in the IRP setting regardless of the timing and ultimate compliance requirements of each state's or EPA's ultimate Regional Haze actions. The hypothetical alternative shutdown dates used in the Company's IRP Regional Haze scenarios were selected to provide a range of portfolio assessment information that either aligns with the earliest assumed SCR installation dates or a range of shutdown dates leading up to the currently approved depreciable lives of these units. The Company clearly communicated throughout development of the IRP that the hypothetical Regional Haze scenarios are intended to provide information for stakeholder review and consideration, but they may or may not be driven by current obligations and, in the case of inter-temporal and fleet-trade-off compliance alternatives, have not been reviewed for acceptability with any agencies, regulators, or joint owners of affected facilities. The provided scenarios reflect *hypothetical* Regional Haze compliance scenarios for the purpose of assessing relative portfolio impacts.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1794

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER's	)
Investigation into Schedule 37 - Avoided	)
Cost Purchases from Qualifying Facilities	)
of 10,000 kW or Less.	)
	)
	)

EXHIBIT REC-CREA/206

2016 RESOURCE & REC RFP
PUBLIC UTILITY COMMISSION OF OREGON
SPECIAL PUBLIC MEETING

May 30, 2017

2016 Resource & REC RFP
Public Utility Commission of Oregon
Special Public Meeting

July 26, 2016

Agenda

- Background
  - PacifiCorp's IRP and RPIP
  - SB-1547
  - Federal Tax Incentives
  - Proxy Resource Costs
- RFP Overview
  - Timeline
  - Resource/REC RFPs
  - Market Response
- Initial Shortlist
  - Bid Selections
- Final Shortlist
  - Bid Selections
  - Evaluation Updates
  - Inter-Temporal Analysis
- Confidential Session

Key Messages

- PacifiCorp will be purchasing RECs from 13 renewable energy facilities—11 of them new, and 10 located in Oregon.
- REC opportunities are currently lower cost than resource opportunities, particularly when considering potential continuing cost declines and on-going availability of the investment tax credit.
- PacifiCorp's RFP process cast a wide net and produced near-term procurement opportunities that will lower long-term RPS compliance costs.
- Procurement of final shortlist REC opportunities will extend PacifiCorp's initial RPS compliance shortfall in Oregon from 2025 to 2028 with rate impacts less than 0.1%.
- PacifiCorp will pursue bi-lateral renewable resource opportunities if cost effective for customers.

Background

PacifiCorp's IRP and RPIP

- **March 31, 2015**, PacifiCorp filed its 2015 IRP, which calls for procurement of renewable energy credits (RECs) to achieve Oregon renewable portfolio standard (RPS) targets through the 20-year planning horizon.

- **February 29, 2016**, Commission acknowledged PacifiCorp's 2015 IRP (Order No. 16-071).

- **March 8, 2016**,Governor Brown signs SB-1547, which, among other things, sets a 50% RPS target for Oregon.

- **March 31, 2016**, PacifiCorp files its 2015 IRP Update with an updated action item to issue renewable resource and REC RFPs.

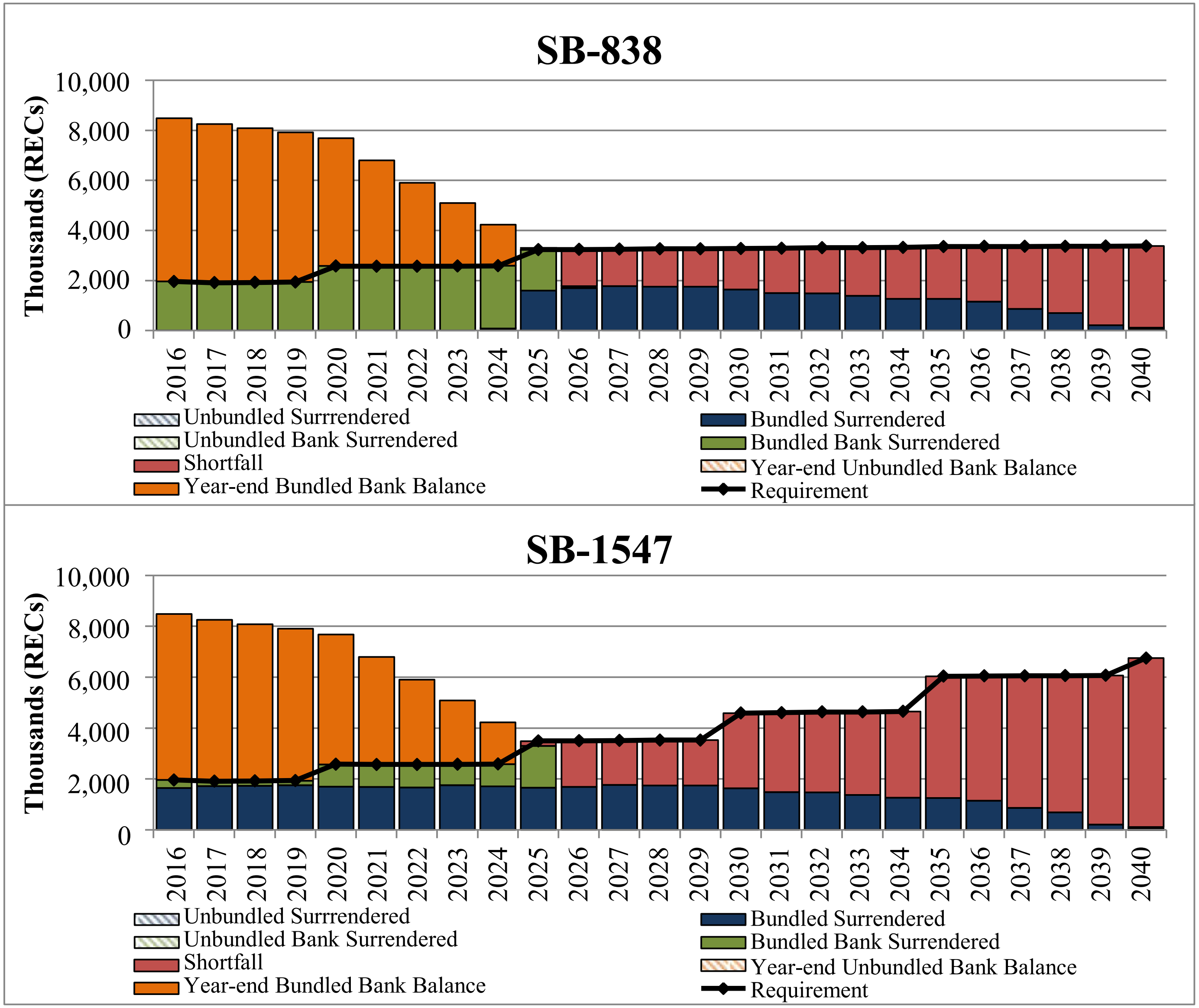
- **July 15, 2016**, PacifiCorp files an updated RPIP, which among other things, includes analysis of SB-1547.

SB-1547 RPS Provisions

Year	SB-838	SB-1547
2016	15%	15%
2020	20%	20%
2025	25%	27%
2030	25%	35%
2035	25%	45%
2040	25%	50%

- REC life (bundled or unbundled) limited to five years (previously unlimited).
- Exceptions:
  - Long-term resources coming online between March 8, 2016, and end of 2022, generate RECs with an unlimited life for the first five years of the resource life.
  - RECs generated before March 8, 2016 have an unlimited life.
- SB-1547 provides flexibility to manage the five-year REC life provisions by eliminating “first-in, first-out” requirements.
- No change to limitation on use of unbundled RECs (no more than 20% of annual RPS target; QFs in Oregon do not contribute to unbundled REC limit).

Impact on PacifiCorp's RPS Compliance Position



Federal Tax Incentives
(Production Tax Credit & Investment Tax Credit)

Construction Begins	Wind (PTC)	Solar (ITC)
Prior to 1/1/2017	100%	30%
Prior to 1/1/2018	80%	30%
Prior to 1/1/2019	60%	30%
Prior to 1/1/2020	40%	30%
Prior to 1/1/2021	0%	26%
Prior to 1/1/2022	0%	22%
On or After 1/1/2022	0%	10%

- Full value of PTC yields between $102 million and $124 million in federal tax benefits over ten years for a 100 MW project.
- This represents between 57% and 69% of initial capital, assuming an initial investment at $1,800/kW.
- A 20% reduction in the PTC reduces these savings by $20 million to $25 million.
- The phase out for the ITC differs from the PTC—the PTC phase out makes near-term procurement opportunities time-sensitive.

Oregon Proxy Wind Resource Cost and Performance

Construction Begins	2015 IRP (Summer 2014)	2015 IRP Update (Spring 2016)
Capital (2014$/kW)	$2,135	$1,672
Capacity Factor	29%	35%
First-Yr Real Lev. Cost ($/MWh)	$60.43	$36.44
Nom. Lev. Cost (2018$/MWh)	$79.48	$47.92

- Market conditions and competition have reduced proxy wind resource capital cost assumptions.
- Technological advancements have improved performance.
- RFP bids are reasonably aligned with 2015 IRP Update assumptions without any third-party wheeling costs, which are significantly lower than current QF prices.
- Projects priced at 2015 IRP levels, or any project that might incur third-party wheeling costs would not be cost-effective as a near-term procurement opportunity.

Resource and REC RFP Overview

Timeline

- April 11, 2016 – RFPs issued to market (*complete*)
- April 19, 2016 – bidder workshop (*complete*)
- May 20, 2016 – RFP proposals due (*complete*)
- June 27, 2016 – finalize initial shortlist bid evaluation (*complete)*
- July 1, 2016 – determination of initial shortlist (*complete*)
- July 8, 2016 – best and final pricing from shortlisted bids (*complete*)
- July 22, 2016 – updated analysis and final bid selection (*complete*)
- August 8, 2016 – complete negotiations (REC RFP)
- August 15, 2016 – execution of agreements (REC RFP)
- September 2, 2016 – complete negotiations (Resource RFP)
- September 16, 2016 – notice to proceed/execution (Resource RFP)

Renewable Resource RFP

- Seeking cost-competitive proposals for renewable resources that can be used to meet state RPS requirements in Oregon, Washington, and/or California.
- While wind PTC benefit in 2016 is driving the near-term opportunity, the RFP targets any resource technology that can qualify for Oregon, Washington, and/or California RPS compliance.
- No aggregate capacity cap or individual project capacity limit.
- Directly interconnecting and delivering to PacifiCorp's west balancing authority area (BAA), or capable of delivering to PacifiCorp's west BAA with the use of third-party firm transmission service.
- Broad range of structures allowed.
  - Asset Purchase and Sale Agreement (APSA)
  - Power Purchase Agreement (PPA), with or without purchase option
  - Alternative structures (i.e., sale lease-back)
- RFP website: http://www.pacificorp.com/sup/rfps/2016-renewables-rfp.html

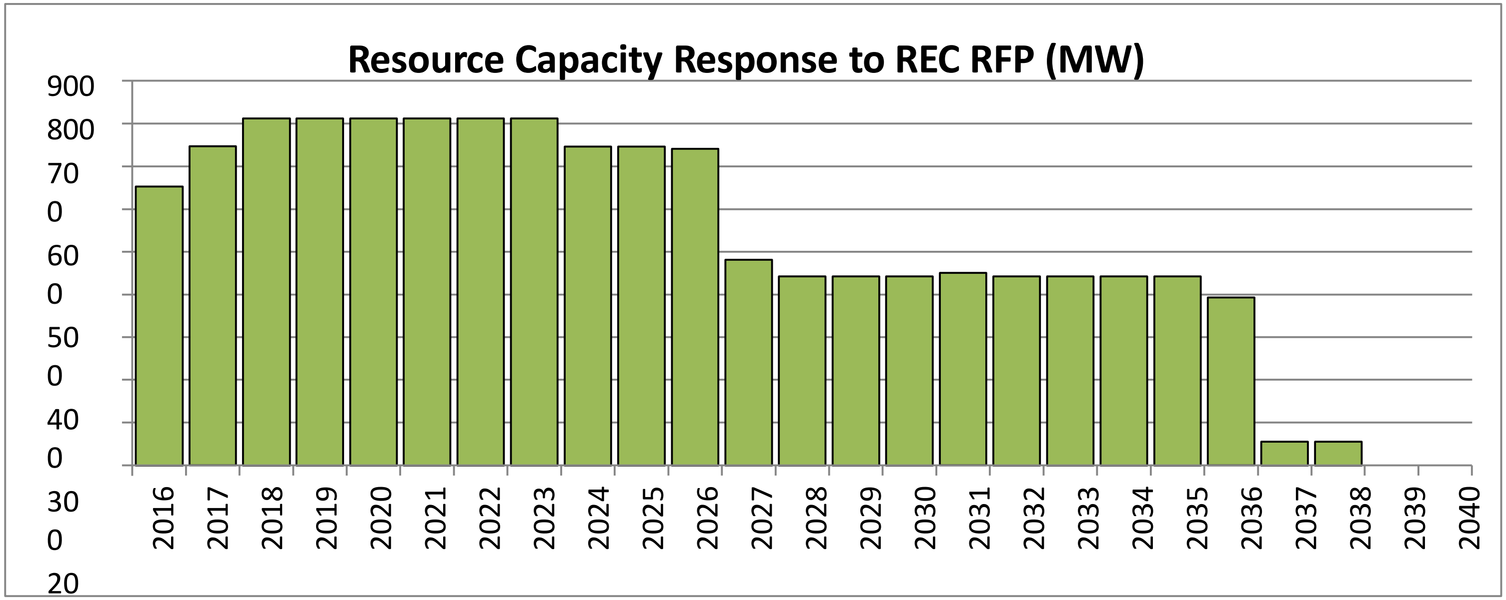
REC RFP

- Seeking cost-competitive bids for RECs that can be used to meet state RPS requirements in Oregon, Washington, and/or California.
- RECs must be sourced from a facility located in Western Electricity Coordinating Council (WECC) territory.
- No maximize size limit, 1,000 REC per calendar year minimum size limit.
- Facility must be registered or will need to be registered in WREGIS.
- RECs must have a vintage on or after January 1, 2007.
- RECs can be firm or resource contingent.
- Broad range of products that align with SB-1547 REC banking provisions.
- RFP website: http://www.pacificorp.com/sup/rfps/2016-rec-rfp.html

Market Response
Resource RFP

Bid Type Resource Type	Number of Projects	Total Capacity (MW_{AC})	Size Range (MW_{AC})
Total Wind	19	3,012	10 – 402
Total Solar	43	2,987	2 – 400
Total Geothermal	4	55	10 – 17
Grand Total	66	6,054	2 – 402

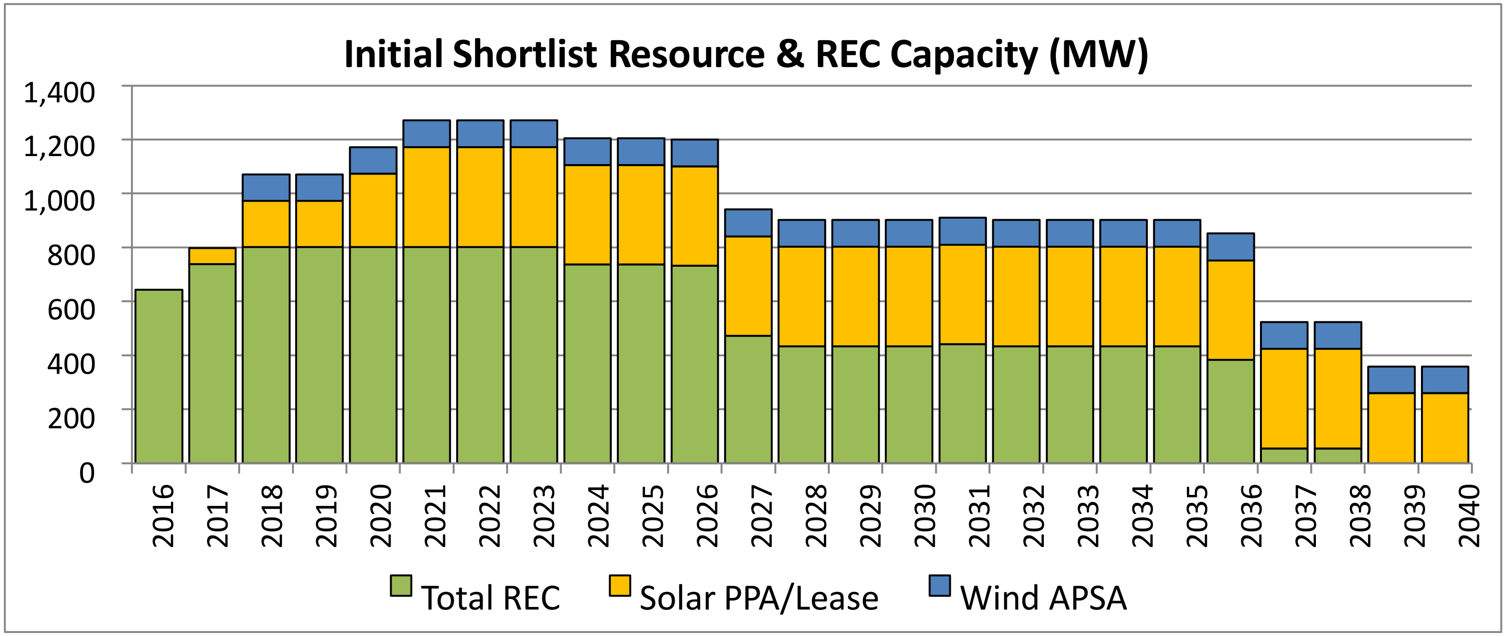
Market Response
REC RFP



- Total volume over 31.2 million RECs from over 800 MW of capacity.
- Approximately 10.5 million of the total REC volume would qualify as “Golden RECs”.
- Approximately 90% of the REC volume is from QF projects.
- If the entire volume were procured to meet the Oregon RPS, PacifiCorp could meet its compliance needs through 2035.

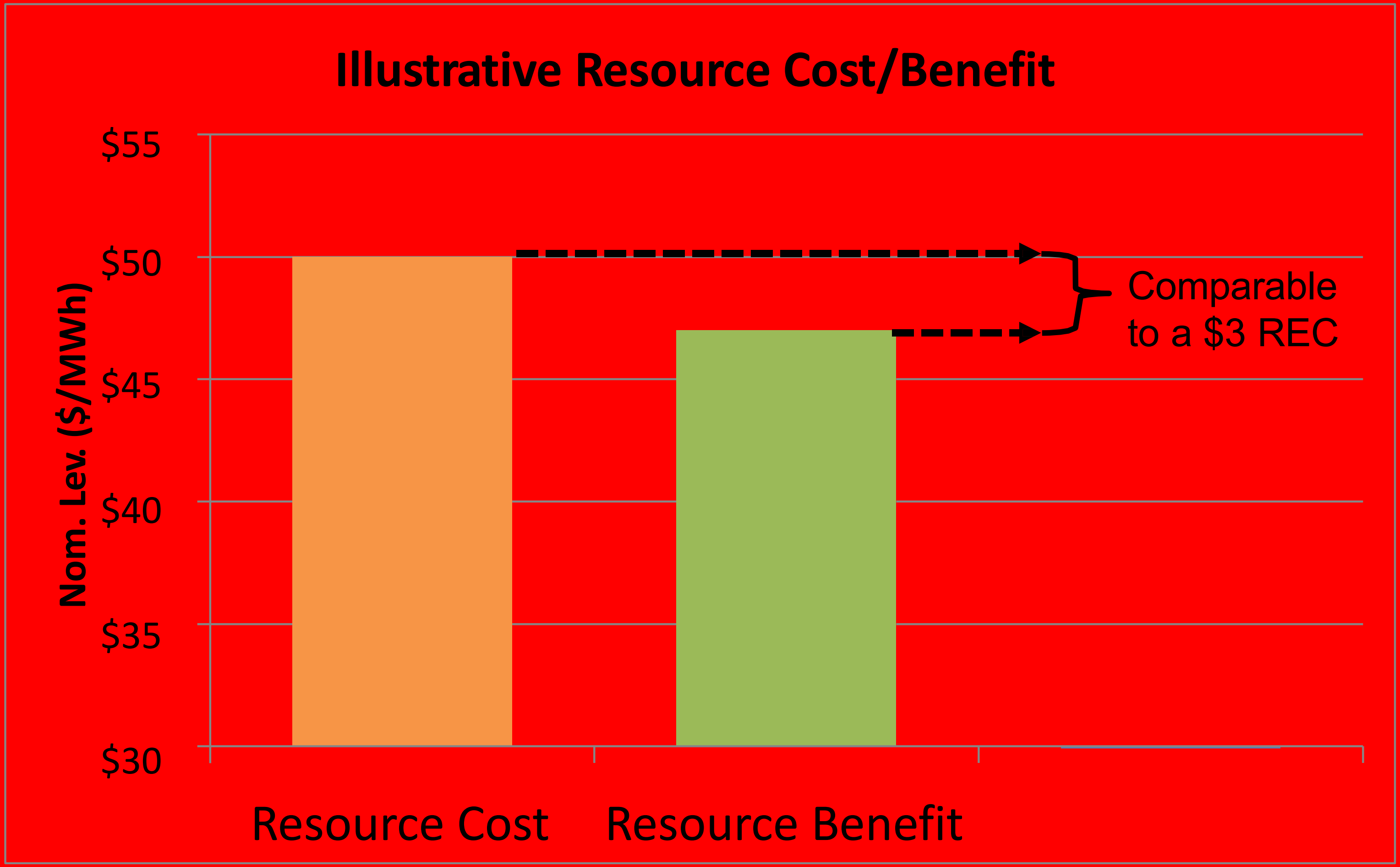
Initial Shortlist

Initial Shortlist



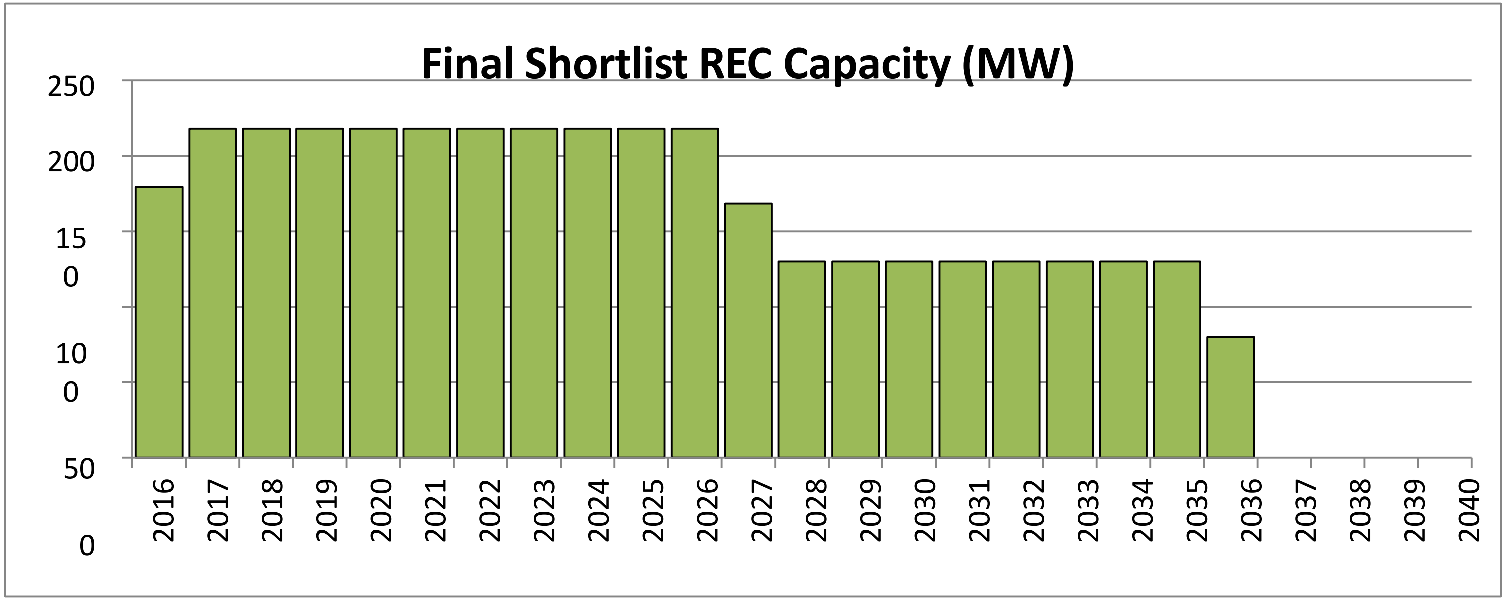
- Eleven resource projects from six bidders totaling just under 470 MW.
- Twenty-nine REC projects from over 800 MW of capacity (~30.5 million RECs).
- The initial shortlist group was selected to be larger than anticipated final shortlist selection to provide opportunity for the most economic bidders to improve their bids before making final bid selections.

Comparing REC and Resource Costs



Final Shortlist

Final Shortlist



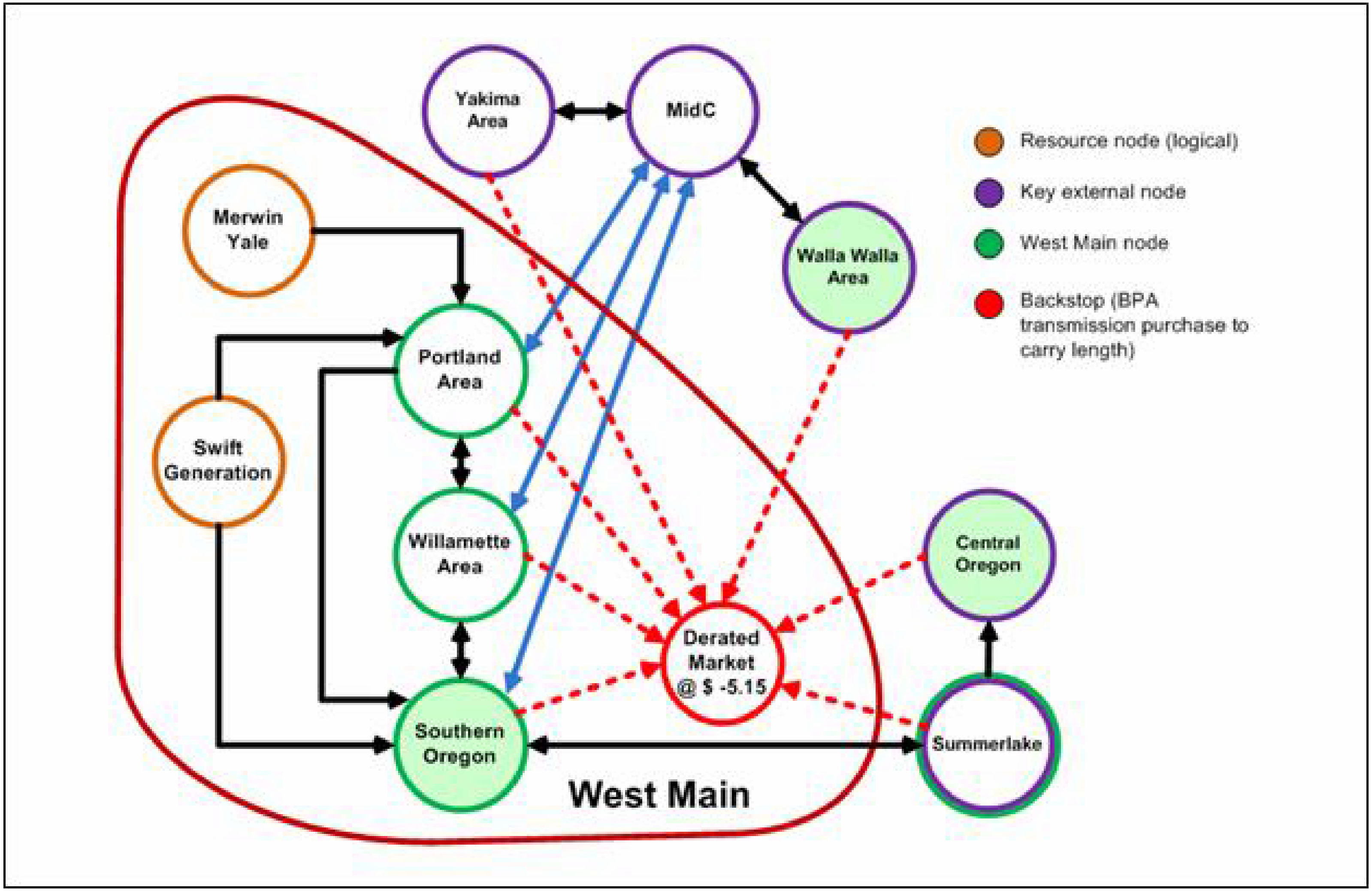
- Initial Oregon RPS shortfall deferred from 2025 to 2028.
- Rate impact for Oregon customers is less than 0.1%.
- No resource bids are in the final shortlist.
  - Uneconomic relative to REC bids.
  - With potential solar cost declines and on-going availability of the ITC, there is no need to lock-in resource bids at this time.

Final Shortlist Evaluation Updates

- All bids were refreshed to incorporate the most recent official forward price curve (June 2016).
- Bids were updated to include capacity factor adjustments based on recommendations from an independent third-party consultant.
- Bids were updated to reflect best and final pricing.
- Bid evaluations include transmission deliverability cost and third-party transmission wheeling costs, as applicable.
- QF bids offering projects under an APSA structure would not reduce costs for Oregon customers.
- Inter-temporal trade-off analysis was used to identify a low-risk, low-cost level of procurement.

Transmission Deliverability Analysis

REC-CREA/206
Fisher/22



Resource and REC Procurement Levels for Inter-Temporal OR RPS Compliance Analysis

Near-Term Procurement Scenario	Description	Oregon-Allocated* Resource RFP Capacity (MW)	Average Annual Oregon-Allocated* Renewable Capacity Offering RECs (MW)
Scenario RFP-A	Lowest Cost	0	72
Scenario RFP-B	Costs > A	0	243
Scenario RFP-C	Costs > B	94	381
Scenario RFP-D	Costs > C	189	504
Scenario RFP-E	Costs > D	241	504
Scenario RFP-F	Costs > E	388	504

*Bids are allocated among Pacific Power states using multi-state protocol system generation (SG) factors. Bids are included in WA only up until the point where RECs would go unused, given the one-year banking limitation. Bids less than 10-years in duration with deliveries beginning 2016 are not included for the CA RPS given limitations for carrying forward RECs from “short- term” transactions across compliance periods.

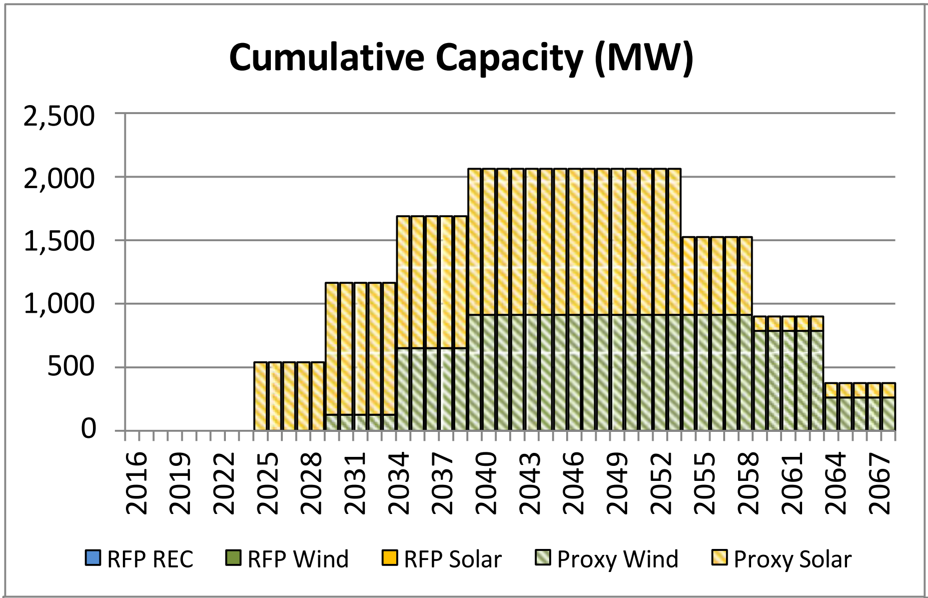
Just-in-Time Compliance Resource Cost and Performance Assumptions

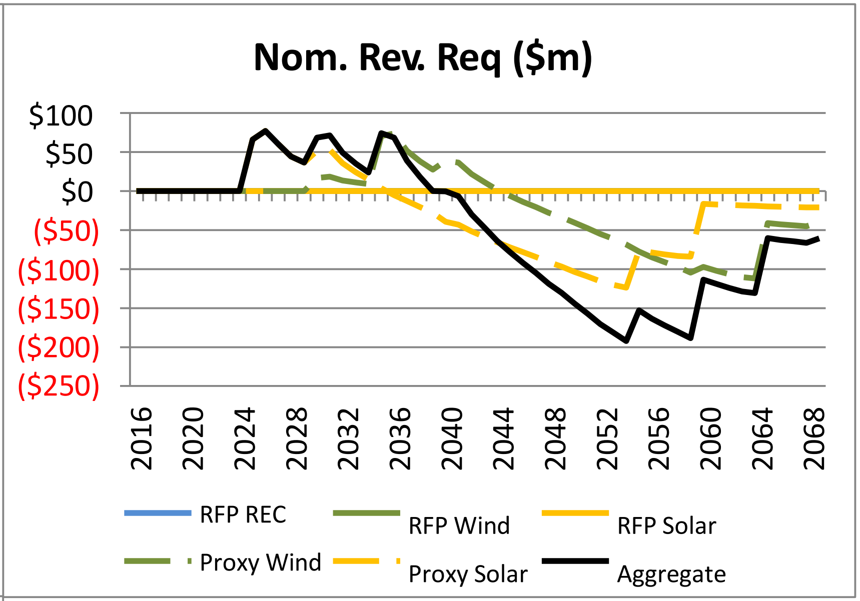
Variable	Scenario JIT-1	Scenario JIT-2	Scenario JIT-3
OR Wind CapEx (2018$/kW)	$1,826	$1,792	$1,757
WY Wind CapEx (2018$/kW)	$1,895	$1,860	$1,823
Wind CapEx Ann. Esc. Rate	2.3%	1.7% through 2025, then 0.0%	1.0% through 2025, then 0.0%
Wind O&M (2018$/kW-yr)	$40.19	$38.80	$38.50
Wind O&M Ann. Esc. Rate	2.3%	2.0%	2.0%
OR/WA Wind Capacity Factor	35.0%	35.0%	35.0%
WY Wind Capacity Factor	43.0%	43.0%	43.0%
OR Solar PV CapEx (2018$/kW)	$2,429	$2,352	$2,019
UT Solar PV CapEx (2018$/kW)	$2,318	$2,244	$1,927
Solar CapEx Ann. Esc. Rate	0.0%	-1.1% through 2025, then 0.0%	-6.0% through 2025, then 0.0%
Solar PV O&M (2018$/kW-yr)	$20.93	$20.81	$20.81
Solar PV O&M Ann. Esc. Rate	2.3%	2.0%	2.0%
OR Solar PV Capacity Factor	29.2%	29.2%	29.2%
UT Solar PV Capacity Factor	31.6%	31.6%	31.6%
Solar PV Degradation	0.5%	0.5%	0.5%

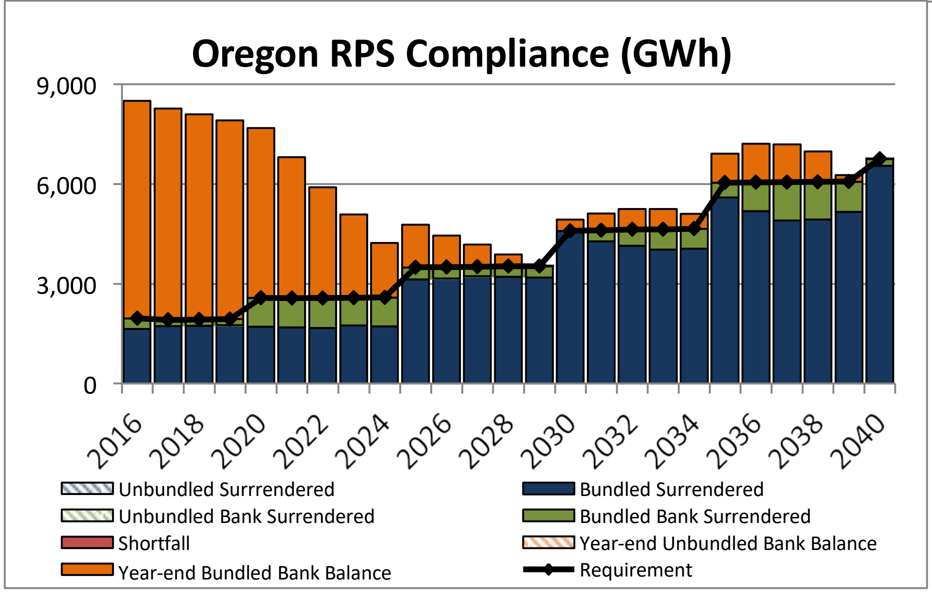
Just-in-Time Proxy Resource Types and Availability

Period	Resource	Limit (MW)	Third Party Transmission	Transmission Network Upgrade
2025 – 2028	OR Wind	400	BPA	None
2025 – 2028	OR Solar	250	None	None
≥ 2028	WY Wind	760 (DJ Retirement)	None	None
≥ 2030	UT Solar	450 (HTG 2 Retirement)	None	None
≥ 2033	UT Solar	+466 (HTR 2 Retirement)	None	None
≥ 2036	UT Solar	+459 (HTG 1 Retirement)	None	None
≥ 2040	WY Wind	+268 (WYD Retirement)	None	None

JIT-3 Summary Results (No RFP Bids)





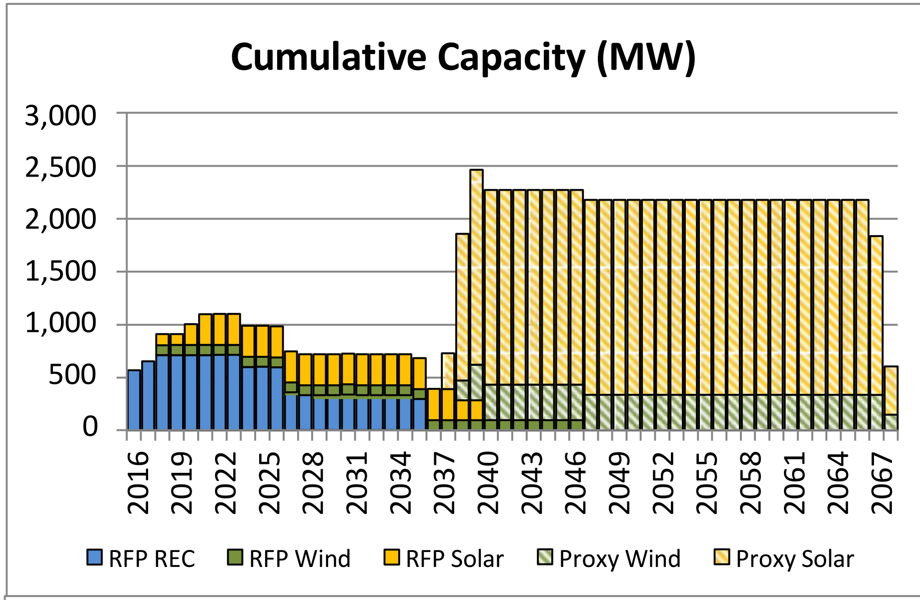


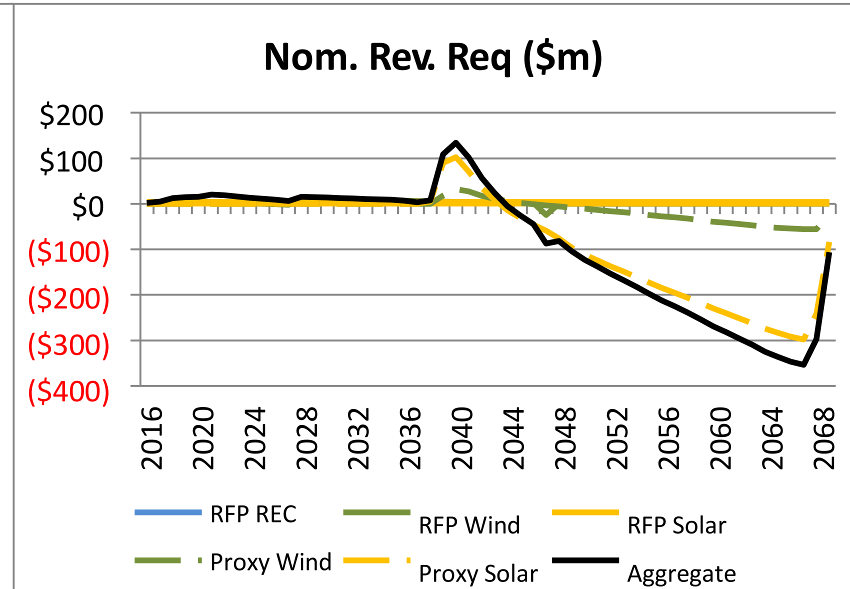
- PVRR = $3m customer cost

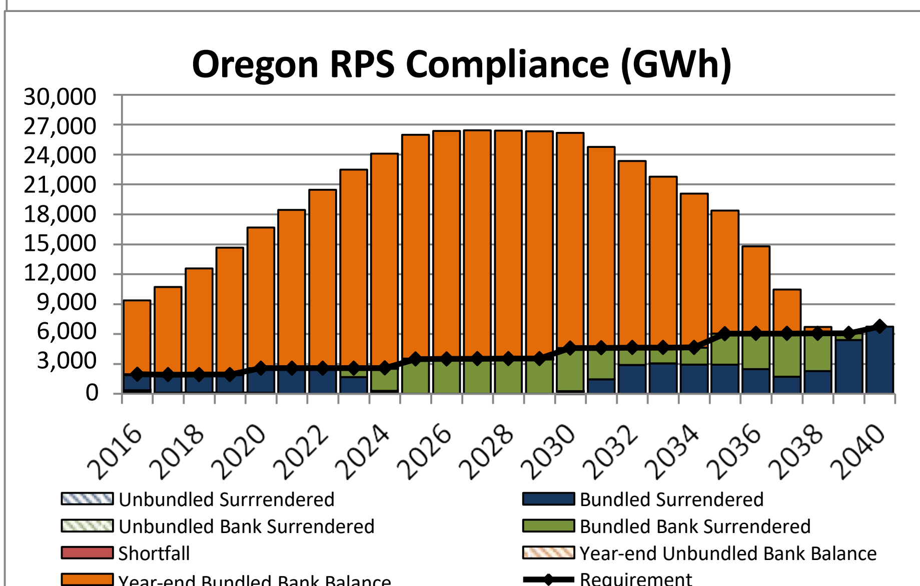
Resource	OR Share of Capacity (MW)	Nom. Lev. Cost/(Benefit) $/MWh
OR Proxy Solar 2025	62	($0.55)
UT Proxy Solar 2025*	477	$12.66
UT Proxy Solar 2030	499	($12.68)
WY Proxy Wind 2030	126	$6.92
WY Proxy Wind 2035	524	$1.04
UT Proxy Solar 2040	113	($23.57)
WY Proxy Wind 2040	262	($1.41)

*Includes $218m for assumed network upgrade costs.

JIT-3 Summary Results (RFP-D)







- PVRR = $101m customer benefit

Resource	OR Share of Capacity (MW)	Nom. Lev. Cost/(Benefit) $/MWh
UT Proxy Solar 2038	340	($22.95)
WY Proxy Wind 2039	188	($1.31)
UT Proxy Solar 2039*	750	($8.04)
UT Proxy Solar 2039*	296	$15.44
UT Proxy Solar 2040	454	($23.57)
WY Proxy Wind 2040	148	($1.41)

*Includes $300m for assumed network upgrade costs.

Inter-Temporal PVRR(d) Matrix
Base Case

REC-CREA/206
Fisher/28

Customer Cost/(Benefit) ($m)	Scenario JIT-1	Scenario JIT-2	Scenario JIT-3
Scenario RFP-A	($107)	($114)	($44)
Scenario RFP-B	($329)	($335)	($52)
Scenario RFP-C	($354)	($391)	($89)
Scenario RFP-D	($372)	($427)	($159)
Scenario RFP-E	($390)	($427)	($152)
Scenario RFP-F	($400)	($409)	($104)

Inter-Temporal PVRR(d) Matrix Emission Benefit Sensitivity

Customer Cost/(Benefit) ($m)	Scenario JIT-1	Scenario JIT-2	Scenario JIT-3
Scenario RFP-A	($109)	($112)	($42)
Scenario RFP-B	($318)	($340)	($34)
Scenario RFP-C	($337)	($370)	($68)
Scenario RFP-D	($356)	($404)	($133)
Scenario RFP-E	($376)	($408)	($129)
Scenario RFP-F	($395)	($398)	($89)

Inter-Temporal PVRR(d) Matrix Wholesale Market Price Sensitivity

REC-CREA/206
Fisher/30

Customer Cost/(Benefit) ($m) – 10% Higher Market	Scenario JIT-1	Scenario JIT-2	Scenario JIT-3
Scenario RFP-A	($110)	($112)	($43)
Scenario RFP-B	($320)	($321)	($37)
Scenario RFP-C	($339)	($373)	($70)
Scenario RFP-D	($357)	($406)	($138)
Scenario RFP-E	($376)	($409)	($134)
Scenario RFP-F	($390)	($393)	($88)

Customer Cost/(Benefit) ($m) – 10% Lower Market	Scenario JIT-1	Scenario JIT-2	Scenario JIT-3
Scenario RFP-A	($104)	($116)	($45)
Scenario RFP-B	($338)	($349)	($68)
Scenario RFP-C	($369)	($409)	($109)
Scenario RFP-D	($387)	($447)	($179)
Scenario RFP-E	($403)	($446)	($171)
Scenario RFP-F	($411)	($424)	($120)

Inter-Temporal PVRR(d) Matrix Future Proxy Resource Sensitivity

Customer Cost/(Benefit) ($m)	Scenario JIT-3 (Base Case)	Scenario JIT-3a (Resource Sensitivity)
Scenario RFP-A	($44)	($32)
Scenario RFP-B	($52)	($198)
Scenario RFP-C	($89)	($196)
Scenario RFP-D	($159)	($173)
Scenario RFP-E	($152)	Not Analyzed
Scenario RFP-F	($104)	Not Analyzed

Conclusions

- PacifiCorp initiated the resource and REC RFP process to explore potential low-cost, near-term procurement opportunities that could lower RPS compliance costs over the long-term.
- Considering uncertainties in future resource costs and transmission availability, near-term procurement levels are limited to opportunities that provide customer benefits among a broad range of inter-temporal scenarios.
- The inter-temporal analysis supports a final shortlist for bids priced below those in RFP Scenario-B, which yields customer benefits even if one assumes steep cost declines for future renewable resource opportunities with sufficient transmission.
- Bids submitted into the REC RFP that provide sufficient volume to defer PacifiCorp's initial shortfall to 2028, which coincides with the assumed retirement date of the Dave Johnston coal unit in eastern Wyoming, are at or below the cost of bids in RFP Scenario-B.
- Given potential for continued declines in solar resource costs and on-going availability of the investment tax credit, PacifiCorp can continue to assess solar and other renewable resource procurement opportunities in future RFPs.

Next Steps

- PacifiCorp will continue to test REC market through future RFPs, thereby taking advantage of dollar-cost averaging.
- PacifiCorp will pursue bi-lateral renewable resource opportunities if cost effective for customers.
- PacifiCorp will submit a filing with the Commission to recover the cost of REC purchases through tariff Schedule 203—Renewable Resource Deferral Supply Service Adjustment.
  - The total estimated rate impact for Oregon customers, based on final shortlist volumes and pricing, is less than 0.1%.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1794

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER's	)
Investigation into Schedule 37 - Avoided	)
Cost Purchases from Qualifying Facilities	)
of 10,000 kW or Less.	)
	)
	)

RESPONSE TESTIMONY OF

GARY MARCUS

ON BEHALF OF THE

RENEWABLE ENERGY COALITION

AND

COMMUNITY RENEWABLE ENERGY ASSOCIATION

May 30, 2017

I. INTRODUCTION

Q Mr. Marcus, please state your name and business address.

A My name is Gary Marcus. I am the owner and General Partner of Falls Creek Hydroelectric Project, LP ("Falls Creek" or "Falls Creek Project"), which is a member of the Renewable Energy Coalition (the "Coalition"). My business address is Falls Creek H.P., LP, PO Box 23508, Eugene, Oregon 97402. The office address is 23858 Butler Rd, Elmira, Oregon 97437.

Q Please describe your background and experience.

A I received a B.A. from Evergreen State College in 1975, an M.S. in Interdisciplinary Studies in History, Economics, and Political Science from the University of Oregon in 1977, and a J.D. in Law from the University of Oregon in 1980. I am a lawyer and a member of the Oregon State Bar, OSB # 810078. I worked as an Oregon legislative assistant in 1977 to State Senator George Wingard, and in 1981 was a full-time volunteer staff member of the Oregon House Environment and Energy Committee. I have 33 years of comprehensive experience in permitting, developing, staffing, owning, and operating a hydroelectric power plant. Additionally, I purchased, owned and operated a wood waste to energy plant in North Power, Oregon and have 12 years' experience permitting natural gas-fired power plant sites in Oregon, Washington, and India. My qualifications pertaining to business development include: founding a knee brace manufacturing company, the Marquette Knee Stabilizer II (MKS II) that I sold in 1987; and the financing, ownership, and operation of a Japanese restaurant with 54 employees in Bellevue, Washington that I sold in 2007. Further details are included on Exhibit REC-CREA/301.

Q On behalf of who are you appearing in this proceeding?

A I am testifying on behalf of the Coalition and the Community Renewable Energy Association in this Oregon Public Utility Commission (the "Commission" or "OPUC") proceeding.

Q Have you previously testified before the Commission?

A No, I have never testified before the Commission. However, in the summer of 1983 Falls Creek Project had a contract dispute with PacifiCorp (then Pacific Power & Light) regarding its initial Power Purchase Agreement ("PPA"). At that time, PacifiCorp had offered a 35-year contract, which I accepted. After I had accepted PacifiCorp's offer, the company retracted the offer due to an internal "change of policy" and offered contracts of a shorter term, for examples terms ranging from 30-years to 34-years. I arbitrated the issue before the OPUC, and the Commission ruled that PacifiCorp had to honor my original 35-year contract term.

Q What topics will your testimony address?

A My testimony will provide background information about the Falls Creek Project that sells its power to PacifiCorp as a qualifying facility ("QF") under a PPA that will expire December 31, 2019. It will also address PacifiCorp's Schedule 37 prices beyond 2020, which will cause the closure of Falls Creek.

Q Please provide a general description of the Falls Creek Project.

A "As built", the Falls Creek Project is a 4.9 MW hydropower project that produces an average annual output of 15,500 MWh. It is a run-of-river project with a 5-

foot high diversion structure and 7,380 foot-long steel penstock (pipe) buried in the mountainside. It has 2,381 feet of vertical head and spins a Pelton wheel turbine, 1,200 RPM. The turbine is connected to a shaft which spins a rotor in a General Electric generator that has a nameplate rating of 4.1 MW, but installed capacity of 4.9 MW produced at 4,160 KV. The voltage is transformed in the switchyard to 20.8 KV where it interconnects to PacifiCorp's distribution line. The point of delivery is PacifiCorp's Foster substation about 20 miles west of the Falls Creek Project, near Sweet Home, Oregon.

Q Please describe the Falls Creek Project with more specificity.

A The Falls Creek Project is an award-winning hydroelectric project that was completed in 1984. I conceived this project in the early 1980s, because I wanted to build a renewable energy project that was environmentally friendly and would take advantage of the latest technologies in power generation. The Falls Creek Project is located 25 miles east of Sweet Home, Oregon in the Willamette National Forest. The project was designed to have a 100-year life expectancy and little or no impact on the environment. Falls Creek has operated efficiently and reliably for 32 years, since 1985. In 1986, the Falls Creek Project won the Oregon Governor's Energy Award in recognition of its environmental compatibility in conjunction with its generating a significant amount of power averaging 15,500 MWH a year, all free of carbon emissions. Falls Creek was the first project in Oregon, and the fourth project nationally, to be certified "Low Impact" by the Low Impact Hydropower Institute ("LIHI") in 2002. LIHI certification is the gold standard for environmentally sound projects with negligible impacts on fish, wildlife, and aesthetics. Because of its low impact status, Falls Creek generates 15,500 renewable energy certificates ("RECs") each year in addition to its 15,500 MWh of electricity. These RECs qualify for Oregon's renewable portfolio standard, which requires small hydro projects of this vintage to have LIHI certification.

Falls Creek is a run-of-the-river project, making use of available streamflow. Water is delivered through 7,380 feet of 30, 24, and 20-inch welded steel penstock, dropping 2,381 feet down the mountainside, one of the highest heads in the United States, to the powerhouse on the south bank of the South Santiam River. The entire length of the pipe is buried, with natural vegetation allowed to cover the route, thus concealing it from sight. The project is located on Forest Service land, and the powerhouse is located directly across the river from a campground.

The powerhouse was designed to blend into the natural environment and not affect campground users. This was successfully accomplished by a camouflaging earthen berm, sound control, and screening the powerhouse and switchyard with native vegetation. The tailrace was designed to look like a natural stream. The tailrace conveys the outfall water from the powerhouse to the South Santiam River. The tailrace camouflage is so successful, that campers prefer to camp directly opposite the tailrace since they think they are camping across from a natural stream. There is virtually no impact on the fisheries' resources, no visual impact from the penstock, nor any interference with the Forest Service's management of its resources or other public uses of the forest.

Additionally, the project is located on the Old Santiam Wagon Road ("SWR"), listed on the National Register of Historic Places in September 2010. SWR was designated as a historic trail by state law (ORS 358.057), which passed in 1995. Falls Creek maintains the road, according to Forest Service wishes to preserve the roadway corridor appearance as it may have looked in 1880. Falls Creek conducts annual tours for area schools, typically third and fourth grade students, with presentations on hydroelectric power production, electricity production and uses, and the historic area where the project is located.

When water traveling through the 2,381-foot penstock reaches the powerhouse, it creates a pressure of approximately 1030 psi. The turbine-generator rotates at 1200 RPM and generates 4.9 megawatts at full-load. It can operate as low as 200 kW, and as high as 4,930 kW.

Since coming online in 1985, Falls Creek has made significant improvements to its original design and equipment to increase production and project life. For example: fish friendly, self-cleaning screens on its diversion structure; improvements to the turbine housing to decrease water splash and outfall that can impede turbine efficiency; state-of-the art Recloser and Generator Relay controls; improvements to our ball valve, lube oil system, bearing Resistance Temperature Detectors and Safety Valve, and installation of a Cathodic Protection System for the penstock to prevent corrosion of the external metal pipe and increase its life by 60 years. We are proud of the care we take of the Falls Creek Project and employ modern and sophisticated equipment and technology that both improve our generation and extend the useful life of the project.

Q Please describe your current QF contract with PacifiCorp.

A Falls Creek's current 35-year term contract was executed in 1983 with power deliveries beginning in December 1984. It will terminate on December 31, 2019. This contract contains both energy and specific capacity payments, based upon demonstrated capacity, and is the original type of non-bifurcated power purchase and interconnection agreement. In addition to negotiating a new contract, Falls Creek will likely need to negotiate a new interconnection agreement before the current contract expires. It is possible that PacifiCorp may require interconnection upgrades for the Falls Creek Project, which would impact its economics. Those potential costs are not accounted for in this testimony.

II. PACIFICORP'S SCHEDULE 37 PRICES ARE TOO LOW TO ALLOW THE FALLS CREEK PROJECT TO REMAIN IN BUSINESS

Q Why are you testifying about PacifiCorp's Schedule 37 prices?

A The Falls Creek Project will be forced to shut down on January 1, 2020, if our only option to is to sell power under PacifiCorp's August 24, 2014 Schedule 37 prices. The prices per kWh PacifiCorp is offering on January 1, 2020 are so low that the project will lose between $325,000 and $400,000 a year during eight of the 15 years of the proposed contract. The accumulated financial loss from 2020 through 2027 will be over $2 million. See Exhibit REC-CREA/302 (Schedule demonstrating the project's losses under the current pricing schedule).

Q Why do you believe the Commission should order PacifiCorp to increase its Schedule 37 prices?

A Falls Creek should be part of PacifiCorp's capacity portfolio. PacifiCorp has included Falls Creek as part of its capacity resources since 1985. PacifiCorp relied on Falls Creek's capacity as part of PUC acknowledged integrated resource plan because PacifiCorp knew Falls Creek would physically operate for those years. Falls Creek has a plant life of another 75 years. Other facilities currently included as PacifiCorp's capacity resources have not been in PacifiCorp's system as long as Falls Creek, and none of the gas-fired plants that are currently part of PacifiCorp's capacity plans will last another 75 years, as Falls Creek could. Falls Creek, therefore, is better suited to be counted in PacifiCorp's capacity sufficiency because of its primacy in the past and longevity in the future. In other words, Falls Creek has been part of PacifiCorp's capacity longer than other projects in that system and can physically outlast existing PacifiCorp projects in that system. Falls Creek is interconnected to PacifiCorp's distribution lines and is in PacifiCorp's service territory. It is logical that Falls Creek should sell to PacifiCorp and not incur the expense to wheel out of PacifiCorp's service territory. It is also logical that PacifiCorp should pay Falls Creek the energy and capacity prices it would pay for a project that has been and will continuously sell to PacifiCorp without interruption. Instead, this 35-year-old project, that should last almost until the next century, is somehow paid like a "new project" without capacity payments from 2020 to 2028.

Q What is the advantage of PacifiCorp retaining Falls Creek as part of its capacity requirements?

A According to current EPA regulations, new natural gas-fired power plants are allowed to emit no more than 1,000 pounds of CO_2 per MWH. Because of its clean energy production, Falls Creek prevents at least 7,750 tons of CO_2 from entering the atmosphere every year from natural gas, and considerably more from coal-fired electricity. Coal-fired plants currently make up over 33% of Oregon's energy mix. The effects of CO_2 emissions on global warming and ocean acidification have been well documented. CO_2 emissions are cumulative; 65% to 80% are dissolved into the oceans causing ocean acidification. The remainder may persist in the atmosphere for over 100 years. Many European countries have imposed a carbon dioxide tax ranging from $7 to $68 per metric ton. If the reduction of CO_2 were valued at $25 ton, then Falls Creek would be paid an additional $193,000 to $339,000 a year to offset natural gas or coal, respectively. This additional money represents the monetization of global warming and ocean acidification and should be added to payments to non-CO_2 producing facilities such as Falls Creek. Furthermore, this is not an experimental technology, but a proven technology from a plant with 32 years of operating experience. To construct any new facility, regardless of its technology, that would produce 15,500 MWH a year free of CO_2 would cost the ratepayers considerably more than retaining an existing and proven facility on-line. Falls Creek cost $4.5 million to build in 1984. It would cost over $15 million to build today. It does not make sense to force the shutdown of an award-winning plant employing successful emission-free technology given the potential future carbon regulation.

Q What pricing schedule do you recommend as an alternative to PacifiCorp's Schedule 37?

A I do not have a specific recommendation, but a modest change in the capacity and energy prices would allow Falls Creek to continue to operate without interruption. Under the August 24, 2016 Schedule 37 prices, Falls Creek will have to shut down on January 1, 2020. Currently, prices under Schedule 37 improve in 2028. This is not tenable for Falls Creek. However, if Falls Creek received prices of about 8.6 cents per KWh beginning in 2022, the owner is willing to go into debt $700,000 to maintain the project. In that case, the project will break even in 2025. Until that time the owner will have to restore reserves to remain in business.

There are other ways in which Falls Creek could potentially operate, if PacifiCorp was directed to collaboratively work with QFs. For example, if Falls Creek could sign a 15-year contract with PacifiCorp in 2020, permitting the project not to operate until prices exceed 7.5 cents. In other words, we would have a 15-year contract, but sit idle for the first eight years, and operate from years nine through fifteen. Under this scenario, Falls Creek can keep the plant warm but not operating for a $50,000 per year loss. The company is willing to absorb that loss while suspending operations until it can generate with a profit. This would make PacifiCorp and the ratepayers revenue neutral since PacifiCorp prices are market-based until 2028. Therefore, PacifiCorp is cost indifferent if it buys power from the grid or Falls Creek during that time. PacifiCorp could then pay Falls Creek according to the existing Schedule 37, operating from 2028 through the next seven years when PacifiCorp says it needs capacity.

Levelization of rates would also be instrumental in allowing the Falls Creek Project to continue to operate.

Q Do existing QFs need to make capital improvements?

A Yes. Falls Creek makes capital improvements on a continuous basis. Capital improvements rely on reserves and under PacifiCorp's Schedule 37, not only will there be insufficient cash flow to operate the plant for a reasonable cost, there will be no cash flow to set aside for capital improvements or to pay debt if capital improvements are required.

III. CONCLUSION

Q Does this conclude your testimony?

A Yes

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1794

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER's	)
Investigation into Schedule 37 - Avoided	)
Cost Purchases from Qualifying Facilities	)
of 10,000 kW or Less.	)
	)
	)

EXHIBIT REC-CREA/301

QUALIFICATIONS OF GARY MARCUS

May 30, 2017

Gary Marcus

Independent Power Producer, Owner, Developer

Education
J.D. University of Oregon School of Law, Eugene, Oregon, 1980.
M.S. Interdisciplinary Studies in History, Economics, and Political Science, University of Oregon, 1977.
B.A., Evergreen State College, Olympia, Washington, 1975.

Companies
President, Frontier Technology, Inc.
General Partner, Falls Creek HP Limited Partnership

Professional Registration
Attorney, member of the Oregon State Bar

Qualifications Pertaining Primarily to Energy Facilities
- 34 years of comprehensive experience, permitting, developing, staffing, owning and operating a hydroelectric power plant.
- Reconnaissance in over 100 hydro power sites in Oregon and Washington.
- Recipient of the Oregon Governor's Energy Award in 1986 for the Falls Creek Hydroelectric Project
- Recipient of the Low Impact Hydropower Institute's renewable energy certificates for the Falls Creek plant.
- Worked as an Oregon legislative assistant in 1977 to State Senator George Wingard, and in 1981 was a full-time volunteer staff member of the Oregon House Environment and Energy Committee.
- Purchased, owned and operated a wood waste to energy plant, in North Powder, Oregon.
- 12 years of experience permitting natural gas fired power plant sites in Oregon, Washington and India.
- Industry advisor to the Low Impact Hydropower Institute 2011 to 2014.

Qualifications Pertaining to Business Development
- Founded a knee brace manufacturing company and brought to market a high-performance knee brace, the Marquette Knee Stabilizer II (MKS II). Sold company in 1987.
- Financed and eventually owned a Japanese restaurant with 54 employees in Bellevue, Washington. Sold restaurant in 2007.

Community Involvement
- Served for six years on the board of directors of the Eugene Symphony
- Past Treasurer of the Jewish Federation of Lane County

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1794

In the Matter of	)
	)
PACIFICORP, dba PACIFIC POWER's	)
Investigation into Schedule 37 - Avoided	)
Cost Purchases from Qualifying Facilities	)
of 10,000 kW or Less.	)
	)
	)

EXHIBIT REC-CREA/302

ECONOMIC ANALYSIS

May 30, 2017

EXHIBIT REC-CREA/302

	Existing Schedule 37		
	Melded Prices Cents/kWh	Annual Losses or Gains	Cumulative Balance
2020	2.85	(352,321)	(352,321)
2021	3.05	(416,295)	(768,617)
2022	3.34	(330,140)	(1,098,756)
2023	3.75	(414,354)	(1,513,110)
2024	4.14	(351,331)	(1,864,442)
2025	4.35	(353,333)	(2,217,774)
2026	4.52	(343,446)	(2,561,220)
2027	4.72	(334,861)	(2,896,081)
2028	**8.69**	130,364	(2,765,717)
2029	**8.87**	116,222	(2,649,495)
2030	**9.07**	130,065	(2,519,431)
2031	**9.26**	134,969	(2,384,462)
2032	**9.47**	143,705	(2,240,757)
2033	**9.68**	150,451	(2,090,306)
2034	**9.89**	158,170	(1,932,136)
2035	**10.11**	165,405	(1,766,731)

	Sustainable Prices 2022		
	Melded Prices Cents/kWh	Annual Losses or Gains	Cumulative Balance Break Even
2020	2.85	(352,321)	(352,321)
2021	3.05	(416,295)	(768,617)
2022	**8.69**	317,383	(451,234)
2023	**8.87**	178,852	(272,382)
2024	**9.07**	234,073	(38,309)
2025	**9.26**	236,395	198,086
2026	**9.47**	264,645	462,731
2027	**9.68**	286,349	749,079
2028	**9.89**	312,045	1,061,125
2029	**10.11**	338,154	1,399,278
2030	**10.11**	338,407	1,737,685
2031	**10.11**	339,075	2,076,760
2032	**10.11**	339,070	2,415,830
2033	**10.11**	338,669	2,754,498
2034	**10.11**	337,743	3,092,241
2035	**10.11**	336,281	3,428,522

Keep in mind that at all times Falls Creek meeds at Least a $500,000 reserve to withstand a drought year or major equipment failure. In other words the plant is not financial secure until 2026 if it starts getting sustainable prices in 2022.