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V. Denise Saunders
Associate General Counsel

March 31, 2017

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
PO Box 1088
Salem OR 97308-1088

Re: LC 66 – Portland General Electric Company's 2016 Integrated Resource Plan (IRP)

Dear Filing Center:

Enclosed for filing in the above-referenced docket are an original and five (5) copies of Portland General Electric Company's ("PGE") Reply Comments. Attachment F and confidential portions of Attachment D will be provided under separate cover under the General Protective Order No. 16-408.

Thank you in advance for your assistance.

Sincerely,

V. Denise Saunders

V. Denise Saunders
Associate General Counsel

VDS:bop

Enclosures

CERTIFICATE OF SERVICE

I hereby certify that I served the foregoing **PORTLAND GENERAL ELECTRIC COMPANY'S REPLY COMMENTS ATTACHMENT D (Confidential)** on the following qualified named persons subject to General Protective Order 16-408, and whose addresses appear on the attached OPUC service list for Docket No. LC 66.

Dated this 31[th] day of March, 2017.

Barbara Parr

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CERTIFICATE OF SERVICE

I hereby certify that I served the foregoing **PORTLAND GENERAL ELECTRIC COMPANY'S REPLY COMMENTS CONFIDENTIAL ATTACHMENT F (two Confidential CDs)** on the OPUC and Commission Staff subject to General Protective Order 16-408 and whose addresses appear on the attached service list from OPUC Docket No. LC 66.

Dated this 31[th] day of March, 2017.

Barbara Parr

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SERVICE LIST
OPUC DOCKET # LC 66

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C = Confidential

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

DOCKET NO. LC 66

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2016 Integrated Resource Plan.	**PORTLAND GENERAL ELECTRIC COMPANY's** **REPLY COMMENTS**

Table of Contents

1. Introduction

Pursuant to the Prehearing Conference Memorandum issued on November 2, 2016, Portland General Electric Company (PGE or the Company) submits these comments in response to the nine parties that filed comments regarding PGE's 2016 Integrated Resource Plan (IRP). PGE also responds to comments and questions raised by parties and Commissioners at the February 16, 2017 Public Utility Commission of Oregon (Commission or OPUC) workshop.

PGE appreciates the interest parties have shown in its IRP. Many of these parties participated in some or all of PGE's nine IRP Public Meetings and workshops conducted over a sixteen-month period. The development of the IRP benefits from stakeholder collaboration and suggestions, particularly as the Company assesses increasingly complex resource planning issues. Their collective contributions helped improve the 2016 IRP and resulting Action Plan, and provided ideas to inform the next IRP. PGE remains convinced the 2016 IRP Action Plan offers the best balance of cost and risk for its customers. It will allow PGE to continue reducing its environmental impact while meeting customers' needs for safe, reliable, and affordable power.

The IRP projects a significant shortfall of resources to meet PGE's customers' future needs. The Action Plan calls for first bringing on more energy efficiency, demand response and renewable resources. Beyond that, it calls for capacity resources to complement renewables, meet periods of peak demand, and help fill the shortfall PGE faces when contracts expire and the Boardman Plant ceases coal-fired operations. The Action Plan is agnostic regarding technology and supply options, and is open to a variety of diverse resources that can meet customers' future electricity needs.

PGE notes that many of the issues raised by parties are considered at length in the IRP and responses to data requests, which PGE will separately incorporate into the record of this IRP docket. In addition, some of the issues raised by parties can be addressed prospectively as enhancements to the next IRP.

In responding to specific issues raised by parties and Commissioners, PGE includes the following new analyses and sensitivities in these Reply Comments:

- Early renewable portfolio standard (RPS) actions
- Analysis of the impacts of PGE's most recent load forecast
- New Energy Trust of Oregon (Energy Trust) energy efficiency forecasts
- Analysis of Stranded Asset Risk
- Additional sensitivities for the planning horizon and end effects
- Additional scoring sensitivities
- Evaluation of additional nine low natural gas price futures

These analyses and sensitivities continue to show that PGE's proposed IRP Action Plan presents the best combination of expected costs and associated risks for the Company and its customers.

PGE also includes a discussion of a potential benchmark resource to be submitted in a renewable request for proposals (RFP). Finally, PGE includes findings from the market research, conducted at the suggestion of the Commission, Staff and other parties to determine if capacity from existing resources may be available for purchase by PGE.

PGE provides a summary of its Reply Comments in **Attachment J**.

2. Action Plan

The Action Plan is the culmination of the IRP. It shows the resource activities that PGE intends to take by 2021 which will allow it to acquire resources that will provide the electric services and performance attributes identified by the preferred portfolio. Because issues related to the Action Plan are at the crux of many of the parties' comments, PGE begins by addressing them first.

PARTIES' COMMENTS:

Many concerns about the Action Plan appear to stem from a lack of clarity about the relationship between PGE's IRP and its proposed RFP(s). One concern that has been raised is that PGE's Action Plan appears "open-ended," since it does not specify generation technologies or fuel sources, and therefore, could result in deferring IRP-type decisions to a later procurement process. OPUC Staff believes the analyses contained in the IRP offer little guidance for (1) the subsequent development of one or more RFPs to fill the claimed capacity needs, and (2) the assessment of the wide range of bids, which may differ significantly in their technologies, durations, and other terms, that may potentially be submitted to the RFP(s)."[1] Similarly, the Northwest Intermountain Power Producer's Coalition (NIPPC) states that the "IRP does not place interested potential bidders on notice as to what kind of resources PGE needs …" and expresses concern that it will lead to an "unworkable RFP…"[2] Sierra Club also raises concerns that PGE has not proposed a clear resource decision. [3]

Several parties make the assertion that the IRP is biased towards utility ownership.[4] Some parties assume use of generic resources for long-term planning will in some way bias an RFP process. The heart of the concern seems to be that PGE has an undisclosed intent to develop a new natural gas combined-cycle plant and that PGE has constructed the Action Plan in a way that will allow it to do so.[5] At the February 16, 2017 Commission workshop, Staff questioned PGE's compliance with the Guideline 13a requirement that the IRP, "[a]ssess the advantages and

[1] Staff's Initial Comments at 3.
[2] NIPPC's Comments at 6-7.
[3] Sierra Club's Comments at 1 and 3.
[4] *See e.g.,* NIPPC at 3; Invenergy at 3-4; Sierra Club at 11.
[5] *See, e.g.,* Sierra Club at 1.

disadvantages of owning a resource instead of purchasing power from another party." Invenergy asserts that the inclusion of this assessment demonstrates bias towards utility ownership.

There were several comments about the types of resources that PGE proposes to procure. Sierra Club suggests that PGE "remove the requirement for minimum 'dispatchable' capacity."[6] Sierra Club also suggests PGE has "dismiss(ed) out-of-state wind as a resource." Invenergy recommends that, "candidate resources should not be evaluated purely on a standalone basis…"[7]

The Citizen's Utility Board (CUB) suggests the Commission "require PGE to issue an RFP for resources that are between 2 and 10 years in length, with no minimum size, and with seasonal products allowed."[8]

A number of parties raise issues pertaining to the design and conduct of PGE's proposed RFP(s): (Sierra Club, NIPPC, Renewable Northwest (RNW), Northwest Energy Coalition (NWEC), and Invenergy). RNW and Invenergy suggest that PGE be required to allow bidders to use PGE transmission in an upcoming RFP.[9] Sierra Club recommends that stakeholders be involved in bid scoring.[10]

PGE's RESPONSE:

2.1. Action Plan Conformance with IRP Guidelines

> ***Consistent with the Commission's IRP Guidelines, the Action Plan identifies resources to be procured and a proposed acquisition strategy***

PGE's goal in developing its Action Plan is to provide specificity about the electric and environmental attributes that it proposes to acquire to fill the needs identified in the IRP. At the same time, PGE aims to ensure that the Action Plan does not limit the types of resources that could compete to provide those services in an RFP.[11]

The Commission's IRP Guidelines, as set forth in Order No. 07-002, are meant to work in tandem with the RFP Guidelines set forth under Order 14-149. The primary goal of the IRP is the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.[12] The IRP is to provide an Action Plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources with the key attributes of each resource specified in portfolio testing.[13] The utility should also identify its proposed acquisition strategy for each resource in its Action

[6] *Id.* at 46.
[7] Invenergy LLC's Comments at 2.
[8] CUB Comments at 11.
[9] RNW at 2; Invenergy at 4.
[10] Sierra Club Comments at 4.
[11] *See* Section 13.3 of PGE's 2016 IRP for discussion of resource acquisition.
[12] Order No. 07-002, Guideline 1c.
[13] *Id.* at Guideline 4n.

Plan.[14] To keep the IRP process separate from the procurement process, the Commission prefers to acknowledge general, not specific, resources in the IRP process.[15]

The RFP Guidelines require a utility to issue an RFP for all Major Resource acquisitions identified in its last acknowledged IRP.[16] Major Resources are resources with duration greater than 5 years and quantities greater than 100 MW.[17] The utility files a draft RFP in a new docket for Commission and stakeholder review.[18]

In the 2016 IRP, PGE, consistent with IRP Guideline 1c, identifies a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for PGE and its customers. The portfolio, *Efficient Capacity 2021,* is described in detail in Section 10.5 of the 2016 IRP. As required by IRP Guideline 4n, the IRP includes an Action Plan with resource activities that PGE intends to take by 2021 which will allow it to acquire resources that would provide the electric services and performance attributes identified by the preferred portfolio. In keeping with the Commission's stated preferences, the Action Plan proposes general, not specific resources.[19] Consistent with Guideline 13a, PGE proposes an acquisition strategy which includes the issuance of RFPs to meet the renewable and capacity needs identified in the IRP.

2.2. Flexibility within the Action Plan

> ***The Commission and stakeholders have historically favored flexible procurement plans.***

The Commission generally does not address the need for specific resources, when reviewing IRPs.[20] Consequently, PGE designed its 2016 Action Plan to allow for flexibility in future resource acquisitions.

The Action Plan identifies a capacity need of up to 850 MW. Updated load forecasts, additional Qualifying Facility (QF) contracts, and other executed contracts may reduce the identified need. Recognizing these potential adjustments, PGE developed a flexible Action Plan designed to meet expected system demand for electricity.

First, PGE is requesting up to 175 MWa (or 515 MW) of renewable resources, through either physical resources or Renewable Energy Certificates (REC). The capacity contribution of the selected resources, if physical, would reduce PGE's identified capacity need as determined in PGE's Renewable Energy Capacity Planning (RECAP) modeling.

Second, PGE is seeking 375–550 MW of dispatchable capacity available annually and the balance available either on an annual or seasonal (winter and summer) basis. As discussed in

[14] *Id.* at Guideline 13a.
[15] *Id.* at 25.
[16] *See*, Guideline 1, Order 14-149, Appendix A at 1.
[17] *Id.*
[18] *See id.* at Guideline 6.
[19] Order No. 07-002 at 25.
[20] Order 14-415 at 2; Order No. 14-358, Appendix A at 15; Order No. 10-457 at 2; Order No. 10-392 at 2.

Section 5.3 of the 2016 IRP, this dispatchability requirement is not tied to a specific technology, as the Renewable Energy Flexibility (REFLEX) analysis found that the three dispatchable technologies tested (a combined-cycle combustion turbine, frame simple-cycle turbines, and reciprocating engines) had similar impacts on upward flexibility imbalances. As stated in the IRP, "though not explicitly tested, other dispatchable low variable cost resources, like hydro or energy storage, would likely contribute to meeting this dispatchability requirement if they are available to be called in anticipation of flexibility challenges in the day-ahead and re-dispatched within the day."[21]

PGE also based this flexible action plan strategy on prior direction from the Commission and comments from stakeholders in previous IRP and RFP dockets. For example, in Docket No. UM 1535, PGE's most recent capacity RFP docket, NIPPC and the Industrial Customers of Northwest Utilities (ICNU) argued for a combined RFP, which would provide additional flexibility to allow the company to look at combined flexible capacity and baseload energy at a single site. Parties in the docket also argued for additional flexibility in the technologies that would be permitted to bid into the RFP. The Commission agreed with the combined RFP approach[22] and also agreed that the RFP should be open to all technologies that could demonstrate an ability to meet certain performance standards.[23] When the Commission approved the combined RFP, it directed PGE to offer more flexibility in selection of baseload turbine manufacturers.[24]

Based on the parties' positions and the Commission's orders in PGE's most recent RFPs, PGE believed it was appropriate and desirable to draft the 2016 Action Plan so that it allowed for flexibility in any subsequent resource procurement process. The Action Plan maintains flexibility in the types of technologies that can be acquired under an RFP, but provides specificity as to the electric and environmental attributes that will be sought in an RFP. PGE has not prejudged the technologies that might be acquired under the RFP, but has provided guidance in the Action Plan as to the nature of the resource need and the electric and environmental characteristics that are necessary to meet the need.

The following table shows the relationship between the resources and operating characteristics identified in the Action Plan and the technologies that could bid into an RFP:[25]

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[21] PGE's 2016 IRP at 146.
[22] Order No. 11-371 at 2.
[23] *Id*. at 5.
[24] Order No. 12-215 at 4.
[25] PGE recognizes that the Commission does not have jurisdiction in this IRP docket to rule on the design of a future RFP and the Company is not asking it to do so here.

TABLE 1. Action Plan need and potential resource attributes

Action Plan	Size	Electric and Environmental Attributes	Technologies Eligible to Bid
Renewable	175 MWa	Oregon RPS eligible, including RECs	Wind, Solar, Geothermal, Eligible Hydro, Biomass
Dispatchable Capacity	375-550 MW	Operational capabilities similar to or more flexible than dispatchable thermal capacity, including: ▪ Annual Availability (and) ▪ Real-time re-dispatchability (and) ▪ Sub-hourly response	Combined Cycle CTs, Combustion Turbine, Reciprocating Engines, Hydro, Geothermal, Energy Storage, Biomass
Capacity (Peak)	Up to 400 MW	Dispatchable product (or) Non-dispatchable, day-ahead firm product, including: ▪ Call limited (or) ▪ Seasonally limited contracts	Day-ahead Capacity Products, Combustion Turbines, Hydro, Energy Storage, Biomass, Geothermal

As the table demonstrates, PGE proposes to issue an RFP to procure the renewable and capacity resource attributes identified in the IRP Action Plan by specifying the electric and environmental characteristics described in the IRP. There are a number of technologies with such attributes that would be eligible to submit proposals to meet PGE's need. The Commission and stakeholders would, consistent with the Commission's RFP Guidelines, review the RFP design in the RFP docket. PGE believes this approach is consistent with the IRP/RFP structure adopted by the Commission in its IRP and RFP Guidelines.

2.3. Ownership Structure

The IRP Action Plan is agnostic to ownership structure and is not biased against out-of-state wind.

PGE's 2016 IRP is agnostic to ownership structure. It does not express a preference for utility-owned generation, power purchase agreements, or any other particular ownership structure. The Commission's IRP Guideline 13 requires utilities to "assess the advantages and disadvantages of owning a resource instead of purchasing power from another utility." PGE includes this discussion in Chapter 7 of the 2016 IRP. The level of detail in this discussion is commensurate with previously acknowledged IRPs. For comparison, Section 9.4 of PGE's 2009 IRP is similar to, albeit shorter than, the discussion in PGE's 2016 IRP.[26]

[26] PGE references the 2009 IRP, as it is the last PGE IRP that preceded an RFP process. Note also that, pursuant to the Commission's Competitive Bidding Guideline 10d, in the RFP process the independent evaluator (IE) will review the risks and advantages of Benchmark Resources and may do the same for third-party bids.

Invenergy's assertion that the discussion of the advantages and disadvantages of resource ownership versus power purchase agreements indicates a PGE's ownership bias is misplaced.[27] PGE included this assessment to comply with the Commission IRP Guideline 13.

Sierra Club's assertion that PGE has dismissed out of state wind as a potential procurement option is false. The Company has enabled a wide array of resources to compete in one or more RFPs by recommending an Action Plan that does not preclude resources based on their technology or location. In fact, PGE conducted extensive analysis in the 2016 IRP to provide insights into the relative value of a wind resource located in Montana compared to a Pacific Northwest (PNW) wind resource.[28] PGE discusses this further in Section 7.2.1 of these Reply Comments.

2.4. Proposal for Mid-Term Procurement Strategy

A term-limited procurement strategy is problematic.

CUB's suggestion that PGE conduct an RFP for resources two to ten years in duration and no minimum size is outside the scope of the Commission's Competitive Bidding Guidelines. Under those Guidelines, the Commission requires the utility to conduct an RFP for resources that are 100 MW or greater in size and are for durations over five years, unless a waiver is granted.[29] The Guidelines do not require an RFP for resources smaller in size or shorter in duration.

While the Commission's Competitive Bidding Guidelines do not prohibit resources smaller than 100 MW or with a duration less than two years from bidding into an RFP, CUB's proposal is problematic from a process standpoint. PGE's capacity needs (identified as up to 850 MW) would not be easily met with bids of one, five, or ten MW contracts (or even smaller). PGE must have the ability to set reasonable minimum sizes. In addition, resources of a short duration (less than five years) would not be available for sufficient time to get through a typical planning and procurement cycle, which combined can take more than four years to complete. Based on the extended time it takes to conduct an IRP and develop an RFP, shorter duration resources would terminate prior to PGE's ability to replace the contract in a future RFP.

Finally, a term-limited RFP likely would reduce the bidding pool and therefore may have the unintended effect of increasing costs to PGE's customers by not achieving the best combination of cost and risk.

2.5. Impact of New Contracts

The renewal of existing hydro contracts and execution of new QF contracts does not change the IRP Action Plan

[27] Invenergy LLC's Comments at 4.
[28] See Section 12.3.4 of PGE's 2016 IRP.
[29] *See*, Guideline 1, Order 14-149, Appendix A at 1.

At the Commission workshops, parties and Commissioners questioned how PGE's renewal of existing hydro contracts might affect the IRP Action Plan. When PGE filed its IRP, the Company had two expiring contracts for hydro resources subject to renewal, i.e., contracts for the Wells and Portland Hydro projects. PGE has executed a contract for output from the Wells hydroelectric project, contemporaneous with the filing of these Reply Comments.[30] The details of the contract are provided in Attachment A.

The execution of the Wells contract does not change PGE's proposed acquisition strategy. PGE still proposes to issue one or more RFPs to acquire the resources identified in the IRP Action Plan. The execution of the Wells contract will simply reduce PGE's need and the amount of resources that PGE ultimately acquires through future procurement efforts. Likewise, if PGE were to renew the Portland Hydro contract, it would also serve to reduce the need and the amount that PGE later acquires (likely by less than 10 MW of capacity). Similarly, PGE has executed new QF contracts since issuing the IRP which also lower the amount to be procured.[31]

In seeking acknowledgement of an IRP Action Plan, the utility should not have to suspend ongoing forecasting efforts or short- and mid-term procurement activities for a sustained period (from IRP filing to subsequent procurement) to ensure constancy in resource needs. Rather the utility should be encouraged to ensure that the amounts ultimately procured reflect actual needs. This cannot be done however if the utility has to restart the acknowledgement process every time a forecast is updated or a new contract is signed. Such a process would place the utility in a position in which, despite the need to acquire resources to serve customer needs, no actual procurement could take place due to the desire to continuously re-examine the Action Plan prior to acknowledgement. In PGE's view, the regulatory process does not mandate such a result. Adjustments for evolving resource needs and procurement targets can, and should, be made in the RFP process. Under the Commission's Competitive Bidding Guidelines, the Commission (and stakeholders) will have several opportunities to review the amounts being procured through the RFP. These include review and acknowledgement of the RFP itself under Guideline 7; and review and acknowledgement of the shortlist under Guideline 13. In PGE's last capacity RFP, the Commission also had the Independent Evaluator review "whether the products sought in the RFP would still be able to meet PGE's needs as they have changed since the issuance of the IRP."[32]

2.6. Existing Bilateral Opportunities

PGE is exploring opportunities to acquire existing capacity

PGE is always open to exploring opportunities to acquire reliable and cost-effective energy and capacity for its customers. During this IRP process the Commissioners, Staff and other stakeholders encouraged PGE to explore whether there are any opportunities to acquire capacity in the marketplace from existing resources, in particular existing hydro generation. PGE agrees

[30] Execution of the contract is consistent with PGE's 2013 IRP Action Plan

[31] **Figure 5** illustrates the relative impacts of these updates on the capacity need as well as a breakdown of the drivers of the remaining capacity need

[32] Addendum to the Final Report of the Independent Evaluator dated January 31, 2013 and filed on February 14, 2013 in Docket UM 1535.

that it makes sense to explore any compelling and time-limited opportunity to acquire existing capacity, particularly while market prices are historically low.

Accordingly, PGE has contacted owners of existing dispatchable generation in the Pacific Northwest to discuss whether they have any available capacity starting in 2021 and, if so, whether they would be willing to submit a bid into a future PGE RFP. These conversations confirmed that there is available capacity in the region for sale to meet the capacity need identified in PGE's Action Plan. PGE's market outreach revealed that generally, volumes between 100 to 400 MW are available from multiple potential sellers. Potential capacity purchase durations vary by seller, but are generally available for five to fifteen years. These discussions were preliminary and did not address important concepts like pricing, deal structure, flexibility, seasonality, and operating and market risk allocation between buyer and seller.

Importantly, most potential sellers of hydro capacity expressed structural concerns about bidding into a utility RFP primarily due to the unique nature of the resources and the seller entities (generally consumer owned utilities and/or government agencies), and their need to demonstrate that any sale achieves the best value for their constituents. The latter concern is difficult to overcome through bidding into another utility's RFP. Given these concerns, PGE was not able to definitively confirm or refute whether the owners of existing hydro capacity would bid into a future PGE RFP. However, the Company's prior RFP history indicates an unwillingness of owners of hydro capacity to bid into PGE's competitive solicitations. In fact, only one owner of capacity from a hydro facility bid into PGE's 2011 capacity RFP.

PGE intends to continue to pursue bilateral discussions to determine the feasibility for developing executable contracts. This will ensure that the Company is able to evaluate potential capacity acquisitions from as many existing resources in the region as possible, including hydro projects, as requested by the Commission, Staff and stakeholders. If successful, PGE will attempt to negotiate one or more transactions with existing dispatchable generation owners in the region to meet its capacity needs. Because any such bilateral transactions would occur outside of an RFP process, PGE will submit executed contracts to the Commission for review along with a request for waiver of the Commission's Competitive Bidding Guidelines. If any such contracts are executed and the Commission waives the RFP Guidelines for such contracts, then, as with the renewal of the Wells hydro contract, the amount to be procured under a subsequent RFP will be reduced by the amount of the new capacity acquired through bilateral negotiations. PGE will commit to providing the Commission with a report on the status of its bilateral negotiations and an update on the amount of capacity that it needs to procure (based on newly executed contracts and approved waivers) before issuing an RFP for capacity.

2.7. RFP Docket

> ***Issues pertaining to the design and conduct of the RFP should be considered in the RFP docket.***

The parties have raised several issues that pertain to the design and conduct of PGE's proposed RFPs. Consistent with the Commission's RFP Guidelines, these issues will be considered in a new docket when PGE files a draft RFP with the Commission. The docket will be a public process with workshop(s) and the opportunity for stakeholder comments. As such, RFP design and implementation issues should not be considered in an IRP docket, but instead addressed at the RFP stage.

2.8. Benchmark Resources

> ***PGE has identified a potential benchmark wind resource and is exploring the development of an energy storage site.***

PGE continues to explore the possibility of submitting a benchmark bid in a future renewable resource RFP.[33] Since issuing the IRP, PGE has identified a potential benchmark resource—a wind project with a nameplate capacity of up to approximately 500 MW and located in eastern Oregon. This project, which qualifies for the Production Tax Credit (PTC), would help PGE meet its RPS requirements, as well as provide a portion of PGE's identified capacity needs. PGE will inform the Commission and parties if, and when, it signs definitive agreements enabling it to submit the project as a benchmark bid.

PGE is no longer considering the submittal of a large-scale energy storage resource as a benchmark bid. PGE is exploring the possibility of developing a site with technical specifications for energy storage (using battery technology) that the Company could offer to potential bidders in an RFP as a PGE ownership option.

3. RPS Analysis

PGE received several comments from parties regarding the plan to pursue early RPS action in order to capture the benefits of Production Tax Credits (PTCs). While some Parties expressed strong support for this item in PGE's Action Plan, others question the sensitivity of PGE's findings to input assumptions and PGE's ability to utilize PTCs. In the sections that follow, PGE demonstrates that the value of early RPS action is robust in a wide range of additional sensitivities and that pursuit of early RPS action continues to present a valuable opportunity for meeting the Company's RPS obligations at the lowest cost to customers.

<u>PARTIES' COMMENTS:</u>

NWEC, RNW, and the Oregon Department of Energy (ODOE) indicate support for PGE's conclusion that procurement of 175 MWa of PTC-eligible renewable resources is preferable on the basis of cost and risk to a strategy of deferred renewable procurement.[34]

ICNU notes that PGE did not test alternative RPS resource addition sizes in the 2018 time frame to explicitly show that 175 MWa was least cost relative to other resource sizes.[35]

ICNU also states that the Company "exaggerates the economic benefits of near-term RPS compliance" by: calculating the net present value revenue requirement (NPVRR) over a 34-year

[33] See PGE's 2016 IRP, Section 13.4.1.3 for further discussion of PGE's potential benchmark bid.
[34] NWEC Comments at 1, 10-11; RNW Comments at 1-3; ODOE Comments at 2.
[35] ICNU at 6-7.

planning horizon,[36] excluding an analysis of PGE's ability to utilize PTCs associated with a utility-owned asset,[37] applying the minimum REC bank constraint,[38] and using the 34% capacity factor assumption provided by DNV GL.[39] ICNU points to a supplemental portfolio analysis conducted by Mr. Mullins to make the assertion that early RPS action "will cost customers nearly $500 million on an NPVRR basis."[40]

OPUC Staff articulates several concerns regarding PGE's RPS strategy, including the ability of PGE to capture the full benefit of PTCs,[41] the current balance of PGE's REC bank, the minimum REC bank constraint applied in renewable portfolio construction,[42] uncertainty around future wind cost reductions,[43] and PGE's unbundled REC breakeven analysis.[44] Staff makes three suggestions for incremental actions regarding PGE's renewable energy strategy: (1) include portfolios that consider delayed RPS procurement in portfolio scoring; (2) develop "a more transparent and realistic unbundled REC analysis for future resource evaluations;" and (3) "revise the Minimum REC Bank strategy."[45]

PGE's RESPONSE:

PGE appreciates the comments from parties seeking to better understand the nature of the economic justification for early RPS action in the IRP. The Company recognizes that the findings in the IRP regarding early RPS procurement to capture the PTC may be counterintuitive given the downward trajectories of renewable technology costs, the typical value of asset deferral, and PGE's current REC bank position. Nevertheless, PGE's analysis shows the value of the PTC to customers is substantial and strongly justifies early RPS action.

In considering PGE's analysis and parties' comments, it is useful to bear in mind the value of the PTC relative to a typical Pacific Northwest wind resource's project economics. The PTC is equal to $23/MWh[46] and is provided in the first ten years of a project's operations. The revenue requirement impact of this tax credit is equal to the PTC value, grossed up for the federal tax rate, which results in a significant cost savings for the project. For example, the levelized cost of energy (LCOE) of a wind resource under IRP assumptions with a commercial online date (COD) between 2018 and 2020 is $75/MWh without the PTC and $55-56/MWh with the 100% PTC. The 100% PTC benefit on real-levelized basis is equal to $20/MWh, or 26% of the cost of the project. This federal tax benefit is significant when compared to the value of other factors that favor delayed procurement, including those discussed in parties' comments.

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[36] *Id.* at 9.
[37] *Id.* at 10.
[38] *Id.* at 11-14.
[39] *Id.* at 14-15
[40] *Id.* at 9.
[41] Staff at 16.
[42] *Id.* at 18-19.
[43] *Id.* at 17.
[44] *Id.* at 20.
[45] *Id* at 21.
[46] Value of PTC provided in 2016. This value escalates over time with inflation.

PGE responds to the specific concerns identified by stakeholders in the sections that follow, including the implications of PTC carryforwards on IRP analysis.[47] In the sections that follow, PGE will demonstrate:

- The value of early RPS action is robust for 100% and 80% PTC-eligible resources with CODs of 2020 and 2021 and is not significantly impacted by the minimum REC bank constraint.
- Procurement of 175 MWa of incremental renewables balances near-term and net present value economic views.
- The benefits of early RPS action remain after accounting for more rapid LCOE declines.
- PGE's findings for early RPS action are robust across additional sensitivities, including zero minimum REC bank, zero load growth, and 20-year NPV assumptions.
- PTC carryforward balances would not eliminate the benefits of early RPS action.
- Short-term reliance on unbundled RECs does not offset the value of early RPS action and a long-term strategy of relying on unbundled RECs introduces additional price risk.

As part of its response, PGE provides a number of sensitivity analyses that serve as a complement to the analysis contained in PGE's 2016 IRP. These sensitivity analyses incorporate PGE's December 2016 load forecast update (see Section 4.1.2 of these Reply Comments for additional discussion of the load forecast update) as well as QF contracts signed through the end of 2016.

3.1. PTC Eligibility, Resource Timing, and Minimum REC Bank

> ***The value of early RPS action is robust for 100% and 80% PTC-eligible resources with CODs of 2020 and 2021 and is not significantly impacted by the minimum REC bank constraint.***

PGE's supplemental analysis first seeks to provide additional information regarding the economics of RPS resource procurement in the 2018-2021 timeframe with various levels of PTC eligibility. The IRS provided guidance regarding safe harbor provisions for PTC eligibility in 2016 in IRS Notice 2016-31.[48] This guidance indicates that a wind project placed "in service by the later of (1) a calendar year that is no more than four calendar years after the calendar year during which construction of the facility began or (2) December 31, 2016… will be considered to satisfy the Continuity Safe Harbor." Under these rules, a resource that meets all other requirements for safe harbor could come online by December 31, 2020 and qualify for 100% PTC eligibility. Some projects in the Pacific Northwest are known to have already satisfied these

[47] In response to Staff's comments regarding the inclusion of RPS Timing portfolios in portfolio scoring, please see **Section 6.4.6**.
[48] IRS Notice 2016-31, June 6, 2016, https://www.irs.gov/irb/2016-23_IRB/ar07.html.

requirements for 100% PTC eligibility in anticipation of a potential drive to develop projects prior to 2021.

PGE considered RPS early action portfolios with various combinations of COD and potential PTC eligibility with a constant RPS addition size of 175 MWa. For each strategy, PGE evaluated the NPVRR difference between the early action portfolio and a Delay Portfolio, in which PGE relies on the REC bank to defer incremental renewable procurement until the REC bank reaches the risk-based minimum levels identified in the IRP. Due to the load forecast update and additional QF contracts,[49] the Delay Portfolio in this supplemental analysis does not require procurement until 2029. More information about the early action and delay portfolios can be found in Attachment B, Supplemental RPS Analysis.

Table 2 lists the resulting NPVRR cost impacts relative to the Delay Portfolio for each combination of COD and PTC eligibility under Reference Case assumptions. As in the IRP, the NPVRR assumes complete utilization of generated PTCs on a contemporaneous basis. Section 3.5 (below) discusses the potential impact of PTC carryforwards. Negative values signify cost savings relative to the Delay Portfolio.

TABLE 2. NPVRR impact of early RPS action relative to delay portfolio

2016$, millions	COD 2018	COD 2019	COD 2020	COD 2021
100% PTC	-72.7	-116.8	-172.8	
80% PTC		-28.4	-88.1	-150.2
60% PTC			-3.4	-68.7
40% PTC				12.7

As shown in Table 2, the value of early RPS action depends on both the COD year and the level of PTC eligibility. Unsurprisingly, the value of early RPS action increases for projects that are eligible for a larger portion of the PTC. In addition, the analysis shows that if the PTC eligibility is held constant, additional savings can be achieved by deferring the resource construction and COD to later years through safe harbor provisions. For example, a project that comes online in 2020 and captures 100% of the PTC through safe harbor provides an additional $100 million in savings relative to a project that comes online in 2018 and also captures 100% of the PTC. Similar to any other asset deferral, the time value of money primarily drives this savings.

In response to Parties' questions regarding the minimum REC bank, PGE also tested the sensitivity of the findings in Table 2 to the minimum REC bank level utilized in portfolio construction. Under this sensitivity, the minimum REC bank constraint is dynamic with resource additions in the portfolio and encompasses fewer RPS compliance risks. These assumptions

[49] PGE assumes that all executed QF contracts through the contract snapshot date result in successful projects. This assumption potentially overestimates the impact of QF contracts on RPS economics given the risk that some of these projects may not come online.

result in a minimum REC bank level of 274 MWa in 2040 (relative to the IRP assumption of 730 MWa) and 83-240 MWa between 2020 and 2035 depending on the portfolio.[50] Table 3 summarizes the NPVRR impacts calculated under this sensitivity under Reference Case assumptions. The analysis demonstrates that the minimum REC bank constraint employed in the 2016 IRP is not a significant driver of the value of early RPS action.

TABLE 3. NPVRR impact of early RPS action relative to delay portfolio under minimum REC bank sensitivity

2016$, millions	COD 2018	COD 2019	COD 2020	COD 2021
100% PTC	-58.8	-102.8	-158.8	
80% PTC		-14.5	-74.1	-141.7
60% PTC			10.5	-60.3
40% PTC				21.1

This supplemental analysis supports the conclusion identified within the IRP that the procurement of a 100% PTC-eligible resource results in a lower NPVRR relative to a strategy of relying on the REC bank to delay RPS procurement.

PGE's supplemental analysis also shows that the highest NPVRR savings can be achieved through procurement of a wind resource with a 2020 COD that captures 100% of the PTC or a wind resource with a 2021 COD that captures 80% of the PTC through safe harbor. PGE notes that the resource modeled in the 2016 IRP with a 2018 COD is a proxy for any resource that is 100% PTC-eligible; thus, procurement of a 2020 COD resource with 100% PTC eligibility is consistent with the IRP Action Plan. The directional findings are also robust across futures for both minimum REC bank sensitivities, as shown in Attachment B.

3.2. RPS resource Sizing

> ***Procurement of 175 MWa of incremental renewables balances near-term and net present value economic views.***

The Company acknowledges that the IRP did not explicitly consider alternative sizes of additions in 2018 to capture 100% of the PTC. In the economic evaluation conducted for PGE's Petition for a Partial Waiver of Competitive Bidding Guidelines and Approval of RFP Schedule, filed with the Commission on May 4, 2016 in Docket UM 1776, PGE tested the relative value of early action using an out-board model under various assumptions regarding resource addition sizes and found that early action was lower cost than 2025 physical compliance at resource addition sizes up to and beyond 253 MWa. This analysis was shared publicly at IRP Roundtable #16-2 on May 16, 2016. The Company limited the 2018 resource addition size to 175 MWa in the IRP on the basis of operational and business judgement given the incremental RPS need identified for 2020 and 2025 in the IRP.

[50] See Attachment B for more information about the minimum REC bank sensitivity.

In response to comments regarding the size of the proposed RPS addition, PGE conducted additional sensitivities in which the addition size was varied for both COD 2018 and COD 2020 resources (both with 100% PTC eligibility). In this analysis, additions in subsequent years were sized to ensure that the minimum REC bank constraint was met in 2034 and 2039, the same approach used for portfolio construction in the 2016 IRP. **Table 4** lists the NPVRR impact of each of these sensitivities relative to the Delay Portfolio. Negative values signify cost savings relative to the Delay Portfolio.

TABLE 4. RPS addition size sensitivities with 100% PTC eligibility

Early Action COD	Addition Size (MWa)	NPVRR Impact Relative to Delay Portfolio (2016$, millions)
2018 COD Portfolios		
2018	125	-72.2
2018	150	-82.4
2018	175	-72.7
2018	200	-62.7
2020 COD Portfolios		
2020	175	-172.8
2020	250	-185.8
2020	300	-193.1
2020	350	-184.3

For both 2018 and 2020 CODs, PGE identified a lowest cost procurement size – approximately 150 MWa and 300 MWa, respectively. There are competing factors driving the economics of early RPS action in the IRP that offset each other at this cost minimizing point. The PTC and the opportunity to defer later RPS procurement both drive increased value for procuring a larger project. The time value of money and decreasing costs of technology put downward pressure on the value as project size increases. The tipping point arises due to a complex interaction between these factors and others less easily understood, like the energy value of wind over time and the avoided capacity additions associated with the ELCC of wind within the portfolio. This tipping point occurs at larger resource addition sizes for COD 2020 resources than for COD 2018 resources—consistent with the finding that deferral of a 100% PTC eligible resource to a later COD brings additional value.

PGE acknowledged at IRP Roundtable #16-2 that 175 MWa was not solely a cost minimizing resource addition size, but that balancing cost and risk was considered. The Company considered many quantitative and qualitative factors in choosing to model this resource size in the IRP, and discusses these factors below.

At the time of portfolio construction, PGE noted that a 175 MWa addition would achieve an RPS level approximately half-way between the 2020 and 2025 RPS obligations. Given uncertainty in both load forecasts and the execution and long-term viability of QF contracts, PGE contended that this was a reasonable target for capturing the value of the PTC. The sensitivities described above support this judgement, as a 175 MWa addition with 100% PTC eligibility remains lower cost than the Delay Portfolio even under a lower load forecast and with additional QF contracts. Moreover, the 300 MWa portfolio with COD 2020 is large enough to defer the majority of incremental RPS resources needed by 2040 to a 2040 COD. While compelling on an NPVRR basis, this strategy may introduce additional risks not quantified in the IRP, including creating a large "cliff" impact where the future procurement requirement is very large due to increased deferral volumes.

While the REFLEX study suggested that PGE could integrate a volume of renewables similar to the 175 MWa wind addition (plus executed QF contracts) with incremental dispatchable resources, PGE did not explore the operational requirements for adding significantly more renewables (although a 50% RPS was found to introduce substantial operational challenges without additional integration solutions). A resource sized at the NPVRR-minimizing point (300 MWa = 882 MW) could introduce integration and operational challenges over such a short period of time.

The IRP evaluates portfolios on an NPVRR basis, as required by IRP Guideline 1c. However, annual cost impacts to customers are also an important consideration. While PGE has incorporated projects in the past that are similar in size to the 515 MW addition, adding nearly 900 MW of new wind by 2020 or 2021would likely present significant procurement, operating and rate impact challenges. PGE notes that the variation in NPVRR impacts across a wide range of sizes are small (on the order of $10-20 million) relative to the total NPVRR savings of early RPS action (on the order of $100-$200 million). The Company maintains that the incremental NPVRR savings associated with "perfect sizing" the addition, based on analytical assumptions, may not be worth the potential adverse impacts in the near term, nor feasible in the market. This position represents a more dramatic, though qualitative, weighting to the near-term impacts to customers than is practiced in the IRP through discounting at the after-tax cost of capital. Nevertheless, PGE contends that an addition of approximately 175 MWa represents a reasonable compromise between managing near-term impacts and net present value economic views.

3.3. Resource Cost Assumptions

> ***The benefits of early RPS action remain after accounting for more rapid LCOE declines.***

While PGE appreciates the opportunity to further discuss technology cost forecasting as it applies to the IRP, PGE notes that technology cost forecasting is outside of the expertise of PGE's IRP staff and that PGE has traditionally relied on third parties to provide technology cost assumptions for the IRP. Based on feedback from stakeholders, PGE engaged DNV GL to provide renewable resource costs and incorporated declining technology cost curves in the 2016 IRP. The Company discussed this topic at Public Meeting #2 on July 16, 2015 and in PGE's Response to OPUC Data Request No. 058.

In response to Staff's comments regarding future onshore wind cost trajectories, PGE reviewed the referenced LBNL report referenced by Staff[51] and compared the median forecast from the LBNL report to the assumptions in the 2016 IRP.[52] The LBNL report discusses four primary components of the levelized cost of wind energy (LCOE) and evaluated how expert forecasts for each of these components would impact the LCOE of wind. These components are: capital cost on a $/kW basis, operating costs on a $/kW per year basis, capacity factor, and project life. **Table 5** shows the median forecasts for each of these components from the report juxtaposed to the assumptions used in the 2016 IRP in.[53] All costs are listed in 2016$.

TABLE 5. Comparison of wind costs and performance parameters.

	Overnight capital cost ($/kW)	Operating cost ($/kW-yr)	Capacity Factor	Project Life (years)
LBNL Study (source: Figure 7, page 20), converted to 2016$				
2014 Onshore Wind (mean baseline)	1,856	61.4	35.4%	20.7
Median forecasted % change (2014-2030)	-12%	-9%	+10%	+10%
Implied 2030 Onshore Wind	1,633	55.9	38.9%	22.8
Implied Average Annual % Change	-0.80%	-0.59%	+0.60%	+0.60%
2016 IRP				
2018 Vintage Onshore Wind	1,667	45.9	34%	27
2030 Vintage Onshore Wind	1,499	45.9	34%	27
Average Annual % Change	-0.88%	0%	0%	0%

While PGE cannot comment on the reasonableness of the forecast in the LBNL report, the median forecast described above provides useful context for understanding the IRP assumptions. The capital cost assumptions in the 2016 IRP are both lower than the median forecast and decline more rapidly (-0.80%/yr. in the LBNL forecast versus -0.88%/yr. in the 2016 IRP). While the 2016 IRP does not contemplate changes in the operating costs (in real terms) or the capacity factor of wind resources, the LBNL median forecast includes a 0.59%/yr. <u>reduction</u> in operating costs and a 0.60%/yr. <u>increase</u> in capacity factors. The LBNL median forecast also includes an increase in the mean project life from 20.7 years to 22.8, while the 2016 IRP wind project life is 27 years regardless of the online date.

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[51] Staff at 17.

[52] LBNL,"Forecasting Wind Energy Costs and Cost Drivers," June 2016, https://emp.lbl.gov/sites/all/files/lbnl-1005717.pdf.

[53] *See* PGE's 2016 IRP, Section 7.4.1.

To consider the potential effect of LBNL's forecast, PGE evaluated LBNL's assumptions in PGE's IRP revenue requirement model. LBNL's median forecast operating cost reductions and capacity factor increases lower the LCOE of a 2030 Pacific Northwest (PNW) wind resource by 8.2%, resulting in an LCOE of $66/MWh (in 2016$) in 2030. This also represents a 13% reduction in LCOE between 2018 and 2030.[54] This analysis did not incorporate the LBNL capital cost reduction forecast because the IRP assumptions are more aggressive. Nor did it include the project life forecast because the 27 year life already exceeds LBNL's 2030 project life forecast.

As noted by OPUC Staff, more rapid reductions in the LCOE of wind may have implications for the value of early RPS action. To test the magnitude of this impact, PGE incorporated the LBNL median operating cost declines and capacity factor improvements into an additional sensitivity on the value of early RPS action. In this sensitivity, the Company found that there is still a $121 million benefit to early RPS action (assuming a 175 MWa COD 2020 RPS resource with 100% PTC eligibility) after accounting for more rapid LCOE declines than are associated with the cost and technology performance data provided by DNV GL. Furthermore, PGE tested even more aggressive cost reductions and found that an LCOE reduction of 30% between 2018 and 2030 would be required to completely offset the value of early RPS action. In addition to the capacity factor and operating cost improvements described above, this would require capital cost reductions of approximately 40% between 2018 and 2030, or about 4% per year. This rapid cost reduction scenario is approximately five times the capital cost reduction rate in LBNL's median forecast and more than double the capital cost reduction rate in LBNL's low forecast.[55]

While the IRP analysis and the LBNL report focus on long-term technology-based trends, PGE acknowledges that these forecasts do not always align with prices seen in the market in a given year. Discrepancies between forecasts and market prices can arise due to a number of factors, including the behavior of labor and commodity markets, the behavior of manufacturers, changes in demand related to policy or other factors, and broader economic phenomena, all of which are highly uncertain and may be transient. For example, a recent U.S. Department of Energy (DOE) report noted that wind turbine prices peaked in 2008/2009 due to several factors, "including a decline in the value of the U.S. dollar relative to the Euro; increased materials, energy, and labor input prices; a general increase in turbine manufacturer profitability due in part to strong demand growth; increased costs for turbine warranty provisions; and an up-scaling of turbine size, including hub height and rotor diameter."[56]

The capital cost declines observed since the 2009/2010 peak[57] may be the result of both the transient factors described above and continued technology and process improvements like those reflected in the long-term forecast provided to PGE by DNV GL. The DOE report also identified no evidence that the short-term cost reduction trends observed between 2010 and 2015 had

[54] If the effect of the PTC is excluded.
[55] PGE's work papers supporting this sensitivity analysis are available upon request.
[56] Wiser, Ryan, Mark Bolinger, Galen Barbose, Naim Darghouth, Ben Hoen, Andrew Mills, Joe Rand, et al. 2016. "2015 Wind Technologies Market Report," p. 53. United States. doi:10.2172/1312474. Accessed March 27, 2017: https://energy.gov/sites/prod/files/2016/08/f33/2015-Wind-Technologies-Market-Report-08162016.pdf
[57] *Id.* The DOE study noted that project cost trends lagged turbine cost trends consistent with "the normal passage of time between when a turbine supply agreement is signed."

continued into 2016: "[e]arly indications from a limited sample of 18 projects (totaling 3.4 GW) currently under construction and anticipating completion in 2016 suggest no material change in capacity-weighted average installed costs in 2016."[58] For these reasons, PGE contends that it would be highly speculative to assume that these short term capital cost trends continue into the future, especially when industry experts (both DNV GL and those interviewed for the LBNL study) tend to forecast more modest capital cost reductions that are in line with the long-term trends.

PGE appreciates the learning curve analysis provided by NWEC for declining solar cost curves and looks forward to continuing to discuss resource cost assumptions with stakeholders in the public processes of future IRPs.

3.4. Additional Sensitivities

> ***PGE's findings for early RPS action are robust across additional sensitivities, including zero minimum REC bank, zero load growth, and 20-year NPV assumptions.***

Stakeholders were also interested in the impacts of more extreme sensitivities on the value of early RPS action, including: zero minimum REC bank, zero load growth, and 20-year planning horizon assumptions. PGE conducted these sensitivities for the portfolio incorporating a 175 MWa COD 2020 RPS addition with 100% PTC eligibility. **Table 6** summarizes these findings. Negative values signify cost savings of early RPS action relative to the corresponding Delay Portfolio and unique Delay Portfolios were designed for each combination of load growth and minimum REC bank assumptions.

TABLE 6. Additional sensitivities for COD 2020 with 100% PTC eligibility

Load Growth Assumption	Min. REC Bank Assumption	NPVRR Planning Horizon	NPVRR Impact Relative to Delay Portfolio (2016$, millions)
Zero load growth (2017-)	2016 IRP Min. REC Bank	34 years (2016 IRP)	-149.2
Dec. 2016 Forecast	**Zero Min. REC Bank**	34 years (2016 IRP)	-144.4
Dec. 2016 Forecast	2016 IRP Min. REC Bank	**20 years (truncated)**	-186.7
Dec. 2016 Forecast	2016 IRP Min. REC Bank	34 years (2016 IRP)	-172.8

[58] *Id.*

While the zero load growth and zero minimum REC bank sensitivities reduced the value of early RPS action by a small amount, the sensitivities show that these assumptions were not significant drivers of the economic value of early RPS action.

Adjusting the net present value calculation so that it considers only the first 20 years of the revenue requirement has a small positive impact on the value of early RPS action because a 20-year horizon does not account for resource additions made in 2040. The early action portfolios and the Delay portfolios have different sized additions in the 2040 time frame because the long-term REC bank management strategy is impacted by near-term actions. This is an important reason for ensuring that the planning horizon is, at a minimum, long enough to encompass the year 2040.

3.5. PTC Carryforwards

PTC carryforward balances will not eliminate the benefits of early RPS action.

At the February 16, 2017 Commission workshop, the Commission asked PGE to provide its analysis of the potential carrying costs that customers may incur should the RFP result in PGE ownership of a resource to meet its RPS compliance obligations. PGE customers receive the benefit of the PTC in the year generated. PGE receives the cash benefit of the PTC in the year the Company utilizes the PTC and reduces tax liability on its tax return, which could be in the current year or a future year depending on numerous factors that impact corporate income and tax liability, many of which are not related to the PTC generating resource.

In this section, PGE provides a complete description of PTC carryforwards and assesses the impact that PTC carryforwards can have on its analysis of early RPS action. While the tax complexities described in this section are important to understand, it is PGE's opinion that priority consideration should be given to the role that the IRP serves in determining resource actions.

PGE's IRP is agnostic with respect to ownership structure and instead focuses on the inherent cost and performance attributes of generic resources. In this context, the IRP identifies resource actions that provide the best balance of costs and risks to customers, and with respect to the PTC, appropriately assumes that wind resources will qualify for PTC benefits that are consistent with IRS guidelines.[59] The IRP does not seek to forecast the detailed financial positions of the utility or potential contractual counterparties, which ultimately determine an entity's ability to utilize or monetize PTCs. To do so would contradict the IRP's common framework used to evaluate generic resources and would introduce assumptions that are difficult, if not impossible, to substantiate or support. Furthermore, PGE notes that while discussed in this section for the purposes of providing clarity, the IRP does not address the regulatory mechanisms to recover PTC benefits.

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[59] IRP guideline 1c establishes the present value of revenue requirement as the key cost metric to use in IRP analysis.

A. PTC Terminology, Accounting, and Ratemaking Treatment

In addition to defining a PTC carryforward, it is important to understand the component parts that determine a carryforward balance. PGE provides the following definitions and accounting and ratemaking concepts related to PTCs and PTC carryforward balances.

1. Generated PTCs: As established by the Internal Revenue Service ("IRS"), this is the credit rate (e.g., $23/MWh in 2016) multiplied by the actual MWh produced by PTC eligible resources.

   - For regulatory purposes, PGE customers receive 100% of forecasted[60] PTCs in the year they are generated through a reduction to expense[61], regardless of the actual amount generated or utilized on PGE's income tax return.

   - PGE's ability to utilize PTCs on its annual tax return has no impact on the amount of generated PTCs.

   - Because the ratemaking benefits provided to customers are based on forecasted generation, the customer is not exposed to the risk that actual generation comes in lower than expected.[62]

   - PTC Generation ends for the three phases of Biglow Canyon Wind Farm by 2018, 2020, and 2021, respectively

   - PTC Generation ends at Tucannon River Wind Farm by 2025

2. Utilized PTCs: This represents the PTCs utilized on PGE's relevant tax return.

3. PTC Carryforward: The PTC carryforward represents the amount of historical year and current year generated PTCs that are not fully utilized on the current year tax return, but are available to be used on future tax returns to offset future tax liability.

   - As allowed by the IRS, PTCs can be carried forward and utilized over a 20 year period from the date of generation. PGE anticipates utilizing all tax credits well before the 20 year carry forward period.

   - PTC carryforwards result in a deferred tax asset and increase rate base.

4. Financial Accounting Considerations: The actual amount of utilized PTCs in any given year will depend on corporate net income, permanent tax differences (i.e., AFDC,[63]

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[60] The forecasted amount of PTCs is the rolling 5 year average of actual generation. In the case of a wind farm that does not have 5 years of actual results, wind studies completed prior to the project's commercial operation date are used.

[61] Oregon Senate Bill 1547 changed the way PTCs are reported. Instead of being treated as a credit to tax expense within a general rate case, they are now included as a credit to variable costs in the annual AUT filing. They are still reported in the AUT on an as generated basis so customers will still receive the benefit of 100% of the forecasted PTC's generated. The 2017 AUT filed in November of 2016 is the first year the PTCs are included.

[62] Now that PTCs are included in the AUT, the difference between forecasted and actual generation is included in the calculation of whether the Power Cost Adjustment Mechanism (PCAM) is triggered.

meals & entertainment), state taxes, and temporary/timing differences (i.e. depreciation, pension expense) between book (GAAP) and tax (IRS) accounting treatment.

- Book and tax temporary accounting differences (GAAP) result in deferred tax assets (increases to rate base) and deferred tax liabilities (reductions to rate base).
- Accelerated tax depreciation (i.e. Wind resources have a 5 year tax life and 27.5 year book life) results in a deferred tax liability and reduces rate base.
    - Accelerated tax depreciation associated with Biglow Canyon (totaling $847 million) has been fully recognized prior to 2016
    - Accelerated tax depreciation associated with Tucannon River Wind Farm (totaling $450 million) will be fully recognized by 2020

B. PGE's Response to Staff and ICNU Comments

Staff claims that customers may not receive the benefits from generated PTCs[64] should an RFP result in PGE ownership, and, as shown in Staff's Response to PGE's Data Request 002, relies on an analysis conducted by ICNU to support its claim.[65] However, ICNU's analysis does not suggest that PTC benefits are withheld from PGE's customers. Instead, ICNU's analysis suggests that carrying costs associated with its forecast of PTC carryforward balances could erode the NPVRR benefit PGE identifies through RPS early action. These are important distinctions to understand.

Contrary to Staff's claims, customers do realize the benefits from generated PTCs. Customers also realize other costs and benefits of wind facilities, including the deferred tax liability resulting from accelerated depreciation, carrying cost associated with any PTC carryforward balance, in addition to the generated PTCs themselves.

For the purposes of illustration, PGE has estimated the benefit customers receive for the generated PTCs and deferred tax liability resulting from a PGE-owned resource. The estimate assumes a 515 MW 100% PTC qualifying wind farm.

- Production Tax Credits – The amount of the credit grossed up for its tax impact is returned to customers in the year generated regardless of PGE's ability to utilize it on its tax return. This decrease to the revenue requirement is the benefit PGE is trying to capture for customers through early procurement of a renewable resource. On an NPVRR basis, this benefit to customers is $414 million for a 515 MW wind farm with COD 2020 and 100% PTC eligibility (See **Attachment D, Table 10**).
- Deferred Tax Liability –A wind farm's tax depreciation is based on 5-year Modified Accelerated Cost Recovery (MACRS) method. This accelerated tax depreciation outpaces book depreciation, which assumes an asset life for wind of 27 years. This timing difference results in a deferred tax liability, which represents future taxes that

[63] Allowance for Funds used During Construction (AFDC).
[64] Staff at 16.
[65] *See* Attachment C, Staff's Response to PGE DR 002.

will be have to be paid when the effects of the accelerated tax depreciation reverse. The deferred tax liability is a significant reduction to rate base during the first 5 years the resource is in service. On an NPVRR basis, this benefit to customers amounts to $191 million for a 515 MW wind farm with COD 2020 (**See Attachment D, Table 11**).

ICNU's reply comments include analysis prepared by Mr. Mullins that attempts to quantify the impact to customers of the carrying cost on a PTC carryforward balance. Mr. Mullins' analysis rests on information that is now out-of-date, having relied on assumptions used in PGE's 2016 General Rate Case (GRC).

The following updates and corrections should be made to Mr. Mullins' analysis to ensure accuracy:

- The commercial operation date should be delayed to 2020 based on IRS guidance that extended 100% PTC eligibility to resources whose construction began prior to 12/31/2016 and achieves commercial operation by 12/31/2020. The updated commercial operation date is more accurate under the current planning timeline.
- The 2016 PTC information should be updated to reflect actual results.
- The PTC generation should be updated to align with current forecasts of both timing of credits as well as forecasted credits. This update also fixes an error in Mr. Mullins' analysis which overestimated credits generated by Tucannon by $86 million.
- The tax liability assumption should be aligned with the IRP assumption of 2.0% inflation. Without this inflation adjustment, Mr. Mullins' analysis effectively assumes that PGE's federal taxes (prior to PTC utilization) are decreasing in real terms over time.
- The NPV calculation should be aligned with the assumptions used in the IRP (2016 NPV with 6.204% after tax weighted average cost of capital).

These updates and corrections to Mr. Mullins' analysis reduce the incremental impact of carrying costs on a forecast of PGE's PTC carryforward balance approximately in half from $233 million to $127 million. In addition to the updates and corrections listed above, PGE disagrees with Mr. Mullins' assumptions on PGE's ability to utilize tax credits.

The tax credit utilization assumption made by Mr. Mullins is simplified and as a result makes his analysis more illustrative in nature than representative of a true forecast of potential carrying costs associated with PTC carryforward balances. Mr. Mullins' analysis assumes tax credit utilization is fixed at the level that PGE assumed for its test year forecast in the 2016 GRC filing. In **Attachment D, Confidential Tables 3 – 9**, PGE includes an analysis that takes into account multiple factors that influence PGE's ability to utilize PTCs, including annual capital growth for items included in the 2018 GRC, accelerated depreciation schedules for both existing resources and a new RPS compliant resource, and other factors that influence PGE's tax position over time. When the analysis is updated to take into account these more current assumptions, the incremental present value revenue requirement (PVRR) associated with carrying costs on PTC carryforwards due to a 515 MW wind resource with COD 2020 and 100% PTC eligibility decreases to roughly $33 million.

PGE provides results for scenarios that consider varying levels of PTC qualification that correspond with the phase out of the credit. PGE's analysis also examines different CODs including 2020 and 2021 which are identified as the most beneficial to customers for early procurement in the results displayed in both **Table 2** and **Table 3** above. **Table 7** presents the incremental NPVRR impact of including the carrying costs of the PTC under each scenario when compared to a scenario where the utility does not have credit carryforwards. Across all scenarios, the forecasted NPVRR impacts of PTC carryforwards are small relative to the NPVRR benefits of early RPS action.

TABLE 7. NPVRR impact of PTC carryforwards associated with a 515 MW wind resource with different PTC eligibility and COD assumptions

COD	PTC Eligibility	Incremental NPVRR (2016$ millions)
2020	100%	32.7
	80%	18.7
	60%	8.6
2021	80%	4.7
	60%	1.3
	40%	0.1

PGE notes that while this PTC carryforward analysis is specific to a utility-owned resource, the IRP does not presume the ownership structure of any of the evaluated resources.

3.6. Unbundled RECs

> ***Short-term reliance on unbundled RECs does not offset the value of early RPS action and a long-term strategy of relying on unbundled RECs introduces additional price risk.***

PGE discusses unbundled RECs in Section 12.3.2 of the 2016 IRP. In that section, the Company presents a comparison of the NPVRR of three portfolios: *Efficient Capacity 2021*, the Preferred Portfolio; *Efficient Capacity 2021 Minimum REC Bank*, which relies on the REC bank to delay RPS action to 2025; and *Efficient Capacity 2021 20% Unbundled RECs*, which delays RPS action to 2025 and incorporates unbundled REC purchases equal to 20% of the RPS obligation during the period 2016-2021, at zero cost. Based on this comparison, PGE concluded that it was lower cost to pursue early RPS action to capture the PTC than it would be to buy unbundled RECs and to defer the next RPS resource acquisition even if unbundled RECs were free. At the request of stakeholders, PGE included a REC "breakeven" analysis, which found that if early RPS action is not pursued (i.e., if PGE relies on the REC bank to defer RPS procurement), unbundled RECs may lower the cost of RPS compliance at prices up to approximately $15/MWh.

PGE does not make RPS procurement recommendations in the IRP on the basis of forecasted REC prices or availability. As stated in the 2016 IRP, "the absence of an organized market enabling efficient pricing of RECs makes it difficult to propose a long-term strategy predicated on unbundled RECs."[66] While a temporary misalignment in timing between resource procurement and increasing RPS obligations throughout the West has resulted in low unbundled REC prices, there is no indication that this environment will persist. Particularly as California approaches a 50% RPS obligation by 2030 and grapples with the prospect of solar-driven renewable curtailment and associated RPS obligation cost increases, and as Oregon approaches a 50% RPS obligation by 2040, an assumption of persistently low unbundled REC prices in the West would be highly speculative. This is exactly the assumption that Mr. Mullins makes in ICNU's supplemental RPS analysis, which claims that early RPS action will result in $472 million of costs to customers relative to a strategy of deferred RPS procurement.

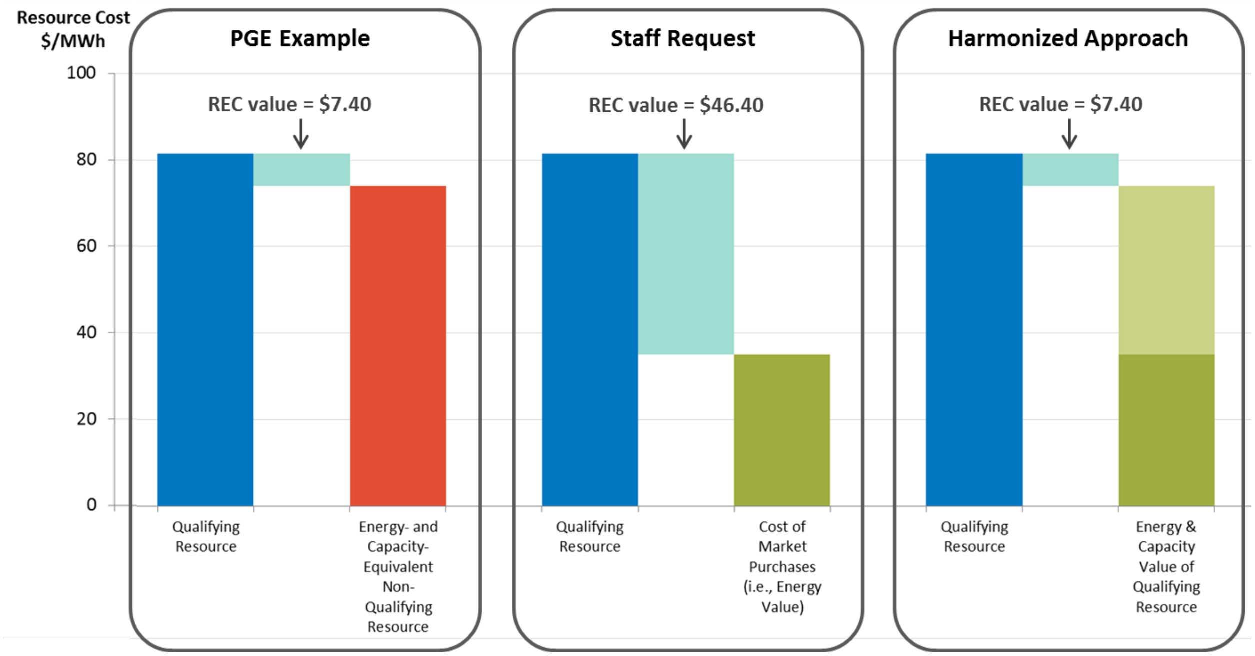
Mr. Mullins' analysis makes two critical assumptions that drive his findings. First, it assumes that PGE will be able to acquire unbundled RECs at a price of $10/MWh to meet 20% of the RPS obligation in every year through 2040. Mr. Mullins' own analysis shows that this assumption drives $283 million of the savings identified for deferred RPS action. Second, as discussed in the prior section, Mr. Mullins' analysis assumes that any resources procured for early RPS action are owned by PGE and that PGE ownership results in an additional $233 million in costs to customers due to PTC carryforwards. As described above, Mr. Mullins' carryforward analysis relies on stale and incorrect data and overly simplistic assumptions regarding PGE's ability to utilize PTCs on a forward basis. PGE's own forecast puts the NPVRR impact of potential PTC carryforwards at roughly $33 million. Additional differences between Mr. Mullins' and PGE's findings may be driven by different assumptions regarding the capacity contribution of renewables and Mr. Mullins' practice of planning to a different and varying reliability standard than is utilized in the IRP through his planning reserve margin (PRM) approximation.

As described in Section 10.6.3 of the 2016 IRP, the theoretical long-run cost of an unbundled REC is equal to the cost difference between the most cost effective qualifying renewable resource and the cost of providing the same amount of capacity and energy with a non-qualifying resource. This is effectively the premium associated with the environmental attributes (in this case the RECs) of the qualifying resource. **Figure 1** illustrates this REC value. In the discussion in Section 10.6.3 in the 2016 IRP, PGE considers a hypothetical example where the renewable resource cost exceeds the capacity- and energy-equivalent non-qualifying resource by 10% ("PGE Example" in **Figure 1**). Staff claims that PGE is inflating the cost of unbundled RECs in this example by using non-qualifying resource costs instead of the cost of wholesale market purchases.[67] Staff's recommendation is equivalent to using the energy value of the renewable to determine the REC value ("Staff Request" in **Figure 1**). Such an assumption would actually

[66] *See* PGE's 2016 IRP at 287.
[67] Staff at 20.

increase the size of the premium associated with REC generation from the qualifying resource.[68] Importantly, such an approach needs to also incorporate the capacity value of the renewable. If both energy value and capacity value are accounted for ("Harmonized Approach" in **Figure 1**), then the calculation is equivalent to the PGE example calculation, in which the qualifying resource cost is compared to the cost of a capacity- and energy-equivalent non-qualifying resource.

FIGURE 1. REC value hypothetical example



PGE notes that the $7.40/MWh price discussed above is based purely on the assumption of a 10% cost premium for RECs described in the hypothetical example and is not indicative of future REC pricing.

As described in Chapter 10 of the 2016 IRP, REC prices are expected to never exceed the theoretical cost premium in the long run (if they were, it would be more cost effective to procure a new physical resource). However, on short time scales, prices could spike as high as the alternative compliance payment (ACP) due to an inability to procure resources in time to meet obligations. REC prices may also fall below this cost premium in years in which renewable generation in the West exceeds RPS obligations. Inefficiencies in the REC market may also introduce deviations from the long run theoretical REC price. Given this degree of uncertainty and the increasing RPS obligations across the West that may put upward pressure on REC prices (toward long run REC value), PGE maintains that long-term REC purchases at speculative price points should not be considered in IRP portfolio analysis.

[68] In the "Staff Request" example, PGE assumes the energy value of the qualifying resource is $35/MWh, the middle of the $30-$40/MWh range identified by Staff in their comments. *See* Staff at 20.

4. Resource Need Assessment

4.1. Load Forecast

As discussed in Section 4.1.2 of the IRP, Itron, a third-party load forecast expert, reviewed PGE's load forecasting methodology and found it to be econometrically sound and consistent with industry standards. The long-term growth rates assumed in the IRP are reasonable based on historical trends and regional growth patterns, reflecting that PGE's service area includes some of the most rapidly expanding areas in the region.

PARTIES' COMMENTS:

OPUC Staff's comments regarding PGE's load forecast can be grouped into the following areas: (1) forecast approach and assumptions, (2) characterization of forecast uncertainty, and (3) industrial load growth forecast. Staff made five requests of PGE, each of which is addressed below.

ICNU cites concerns of stale forecast input assumptions and requests a reconciliation of the load forecast in the IRP to the forecast provided for 2017 in Docket UE 308.

Staff and CUB note that PGE's approach does not directly incorporate distributed generation and specifically rooftop solar PV into its load forecast model.

PGE's RESPONSE:

4.1.1. *Methodology*

> ***PGE's load forecast is based on reasonable assumptions and a sound methodological approach***

Consistent with the Commission's 2013 IRP acknowledgement order, PGE reviewed its load forecasting methodology and contracted with Itron to perform an independent third-party evaluation. Itron found PGE's general approach to be consistent with industry standards and made several recommendations, which PGE reviewed and adopted, to improve alignment with industry practice. PGE presented its load forecasting methodology to Staff and stakeholders in numerous stakeholder meetings and workshops, including review of the additional analysis performed to implement Itron's recommendations. Despite the expert confirmation and the opportunities to provide feedback to PGE, Staff's comments express concerns with PGE's load forecast methodology.

In forecasting, there has been differentiation between structural (or causal regression) econometric models and purely time series econometrics methods. Time series models are based solely on patterns in historical series. PGE's load forecast models are causal regression models; grounded upon a structural relationship between economic variables and energy deliveries among PGE's different customer segments. PGE has followed this general approach for a number of years, with review by many parties in many regulatory proceedings with general recognition of the inherent value of an explanatory model that provides information about the conditions that influence energy deliveries. Staff raises the possibility that a number of PGE's manufacturing series may exhibit non-stationary distributions, which might lead to a statistical issue in manufacturing sector models.[69] Economic theory often implies relationships between variables that are subject to unit root non-stationarity. Augmented Dickey Fuller test results provided by Staff find that several of the seven manufacturing series fail to reject the null hypothesis of a unit root. Four of these manufacturing models are "flat" forecasts, for which these results are irrelevant. The remaining three manufacturing models contain economic variables with a sound theoretical, historical relationship. PGE examines the statistical characteristics of its load forecast models at the time of each forecast, with extensive analysis of error structure and model fit statistics.

Staff cites concern with the likely changing relationships between energy deliveries and economic drivers.[70] This issue has been an emerging conversation within the industry, and one that PGE has been transparent in discussing with its stakeholders.[71] While it presents a challenge in load forecasting, specifically without knowledge of what the future brings and to what extent this trend will persist, it is appropriate to identify reasonable assumptions and create a forecast that is useful within the context of such assumptions.

4.1.2. *Forecast Vintage*

PGE provides analysis of the impact of its latest load forecast on resource need.

PGE's two-year IRP cycle requires that the load forecast be "locked down" very early in the IRP process. While PGE may update some input assumptions later in the process, such as the economic outlook, these updates cannot be fully incorporated into the IRP without restarting the entire cycle. IRP portfolio development is a complex and rigorous undertaking and requires specific timelines for timely completion and accurate representation throughout the public process. Nonetheless, PGE recognizes that newer forecasts are developed during the IRP cycle. While PGE cannot use updated forecasts to recreate all of the IRP analyses, PGE has provided in Section 4.2.9 of these Reply Comments an updated assessment of resource need based on its most current (i.e., December 2016) load forecast.

ICNU recommends that PGE update its forecast to include current Oregon Office of Economic Analysis (OEA) data.[72] PGE's most recent load forecast, released in December 2016, relies on the OEA economic outlook from November of 2016, actual load data through October 2016, and long-term direct access elections effective in January 2017.[73] **Table 8** below summarizes OEA

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[69] Staff at 6.
[70] *Id.* at 5-6.
[71] PGE Public Meeting #1, April 2, 2015, Itron Presentation at slide 18.
[72] ICNU at 24.
[73] The IRP load forecast was developed in June 2015 using the OEA's May 2015 economic outlook, included actual load data through April of 2015 and direct access elections effective January 2015.

economic forecast releases by vintage, showing only minor changes to the trajectory of economic inputs.[74]

TABLE 8. Summary of economic assumptions, average annual growth rates by OEA vintage

	Oregon Employment Growth (2016-2021)	Oregon Population Growth (2016-2021)
May 2015	1.7%	1.2%
November 2016	1.5%	1.3%
February 2017	1.6%	1.3%

4.1.3. *Response to LBNL Report*

The LBNL study is a flawed comparative analysis of PGE's load forecasting performance.

Stakeholders cite to a 2016 Lawrence Berkley National Laboratory (LBNL) Study, "Load Forecasting in Electric Utility Integrated Resource Planning," to support their concerns with PGE's load forecast. [75] The study concludes that utility IRPs fail to sufficiently address load uncertainty as evidence of PGE's historical load forecast variance. PGE agrees with the study authors that it and other utilities were unable to anticipate the Great Recession, the historically slow recovery, and the impact on electricity demand, and therefore, load forecasts prior to the Great Recession did over-forecast the time period of 2009 to 2014. However, the LBNL study mischaracterizes PGE's forecast performance as an outlier amongst its peers.

The LBNL study did not control for weather, nor did the study consider the varying impacts of the Great Recession in comparing the performance of load forecasts in different regions and forecasts created in different years. LBNL also made some incorrect assumptions about PGE's data, resulting in inflated error calculations. PGE worked with LBNL to better understand its methods and discuss these data assumptions. A memo from LBNL, in which LBNL "corrects the record" on two of the most notable tables and provides additional clarifying information with regard to its use of PGE's load forecast data, is provided in Attachment E.

Staff cites Table 3 of the LBNL study, which reports PGE as having 19% cumulative forecast error between 2007 and 2014.[76] PGE and LBNL repeated the calculation, again without weather normalization for consistency, and found a cumulative error of approximately10% for that period. While this still shows overestimated loads during that period, it demonstrates that PGE is not a poor performing outlier amongst its peer utilities, even during that challenging recessionary period.

[74] The most recent forecast was posted February 22, 2017. Accessed: March 27, 2017. https://www.oregon.gov/das/OEA/Pages/forecastecorev.aspx.
[75] Staff at 7; ICNU, Comments of B. Mullins at 7.
[76] Staff at 7.

Table 4 of the LBNL study presents PGE's reported base average annual growth rate (AAGR) in the energy forecast to be 2.6%. In fact, LBNL double counted the impacts of energy efficiency; the impacts were already embedded in the base forecasts. The corrected AAGR for Table 4 is 1.8%.

LBNL also used incorrect data for PGE's actual net system loads in Table 13, a table Staff cited and included in its comments. The impact of using the correct data increases PGE's actual load growth rates albeit not dramatically; thus, PGE did not ask LBNL to "correct the record" in this table.

In short, while the LBNL study provides useful recommendations regarding planning under uncertainty, it has a number of flaws in its use as a comparative analysis of utility load forecasting performance.

4.1.4. ***Compliance with IRP Guideline 4b***

> ***PGE has provided sufficient detail to support its load forecast and comply with IRP Guideline 4b.***

Staff contends that PGE does not clearly describe its load forecasting methodology and requests that PGE provide additional information on the assumptions and approach.[77] At the February 16, 2017 Commission workshop, Staff claimed that PGE did not address the load forecast requirements set forth in Guideline 4b of the Commission's IRP Guidelines. Guideline 4b requires "*[a]analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions."*

Chapter 4 of PGE's 2016 IRP describes the load forecast process in detail and explains the major assumptions and drivers of the load forecast. High and low load-growth scenarios are discussed in Section 4.1.5 of the 2016 IRP, and stochastic load risk is thoroughly discussed in Chapter 5 of the IRP. PGE allowed for stakeholder engagement and input in the development of the forecasting methodology throughout the IRP public process, including at two stakeholder roundtables and at a technical workshop devoted to load forecasting.

PGE has used the public process to explain the technical details related to its load forecast method to the stakeholder group, as this allows for dialogue around a fairly technical model. PGE is willing to work with Staff to optimize the balance between readability and technical detail of the load forecast models in the IRP report itself during future IRP cycles.

PGE's forecast methodology uses regression-based structural models to describe the relationships between energy deliveries and various economic, weather and indicator variables. Short-term models are sector based, leveraging sector level economic relationships where possible, while the long-term models are aggregated to capture convergence to long-term equilibrium growth rates. This is consistent with models of economic growth which generally reflect near term business cycle trends but converge in the long-term. **Table 9** contains a

[77] Staff at 5, 9.

summary of the drivers used by model for the short and long-term energy forecasts used for the 2016 IRP load forecast. Each time PGE updates its load forecast, models are re-estimated using the most recently available information, and specifications, including specific drivers, are analyzed.

TABLE 9. Load forecast explanatory variables[78]

Model Segment	Regression	Output	Time Period	Weather (HTD)	Weather (CLD)	Weather (Wind)	Economic Driver
Short Run Model	Residential						
	Single Family, Space Heat	UPC	01/04-04/15	HTD50, HTD60	CLD70	WIND*WINTER, WIND*SPRING	NONE
	Single Family, Non Heat	UPC	01/04-04/15	HTD60	CLD65	WIND*WINTER	NONE
	Multi Family, Space Heat	UPC	01/04-04/15	HTD50, HTD60	NONE	WIND*WINTER, WIND*SPRING	NONE
	Multi Family, Non Heat	UPC	02/04-04/15	HTD45, HTD60	CLD65	NONE	NONE
	Mobile Home, Space Heat	UPC	01/04-04/15	HTD50, HTD60	CLD70	WIND*WINTER	NONE
	Mobile Home, Non Heat	UPC	03/04-04/15	HTD40, HTD60	CLD65	WIND*WINTER	NONE
	Other	MWh	02/04-04/15	HTD50, HTD60	CLD70	WIND*WINTER	NONE
	Commercial						
	Food Stores	MWh	01/00-04/15	NONE	CLD60	NONE	NONE
	Transportation & Utilities	MWh	01/04-04/15	HTD40	CLD65	NONE	OENTTU
	Other Trade	MWh	01/00-04/15	HTD55	CLD60	NONE	NCS7
	Restaurants	MWh	02/90-04/15	HTD50	CLD60	NONE	OENNMF
	Other Services	MWh	01/00-04/15	HTD60	CLD60	NONE	OENSV
	Office, Finance, Insurance & Real Estate	MWh	03/04-04/15	HTD40, HTD65	CLD60	NONE	OENSV Lag1
	Miscellaneous Commercial	MWh	01/00-04/15	HTD60	CLD60	NONE	OENNMF
	Healthcare	MWh	01/01-04/15	HTD50	CLD60	NONE	OENEHS
	Merchandise Stores	MWh	01/00-04/15	HTD55	CLD60	NONE	OENRT
	Government and Education	MWh	06/03-04/15	HTD65	CLD60	NONE	OENGVT
	Lodging	MWh	01/05-04/15	HTD55	CLD65	NONE	NONE
	Manufacturing						
	Food	MWh	01/05-04/15	NONE	CLD60	NONE	OENTNA
	Lumber	MWh	01/08-04/15	NONE	NONE	NONE	NONE
	High Tech	MWh	01/02-04/15	NONE	NONE	NONE	NONE
	Other	MWh	01/95-04/15	NONE	NONE	NONE	OENTNA
	Paper	MWh	01/02-04/15	NONE	NONE	NONE	NONE
	Metals	MWh	01/05-04/15	NONE	NONE	NONE	NONE
	Transportation Equipment	MWh	01/99-04/15	NONE	NONE	NONE	OENTEM
Long Run Model	Residential	MWh	02/90-04/15	HTD50, HTD65	CLD65	NONE	OENTNA
	Secondary	MWh	02/90-04/15	HTD55	CLD65	NONE	OENTNA
	Primary	MWh	01/90-01/13	NONE	NONE	NONE	GDPR

[78] Variable Definitions: Economic variable used include various subsets of Oregon employment data: OENTNA (Total Non-Farm), OENTTU (Trade, Transportation and Utilities), OENSV (Services), OENNMF (Non-Manufacturing), OENEHS (Education and Health Services), OENRT (Retail Trade), OENGVT (Government), OENTEM (Transportation Equipment Manufacturing), RGDP (US Real Gross Domestic Product), and for one model, residential customer count (NCS7). Weather variables used include Heating Degree Days (HTD) and Cooling Degree Days (CLD) at varying set points.

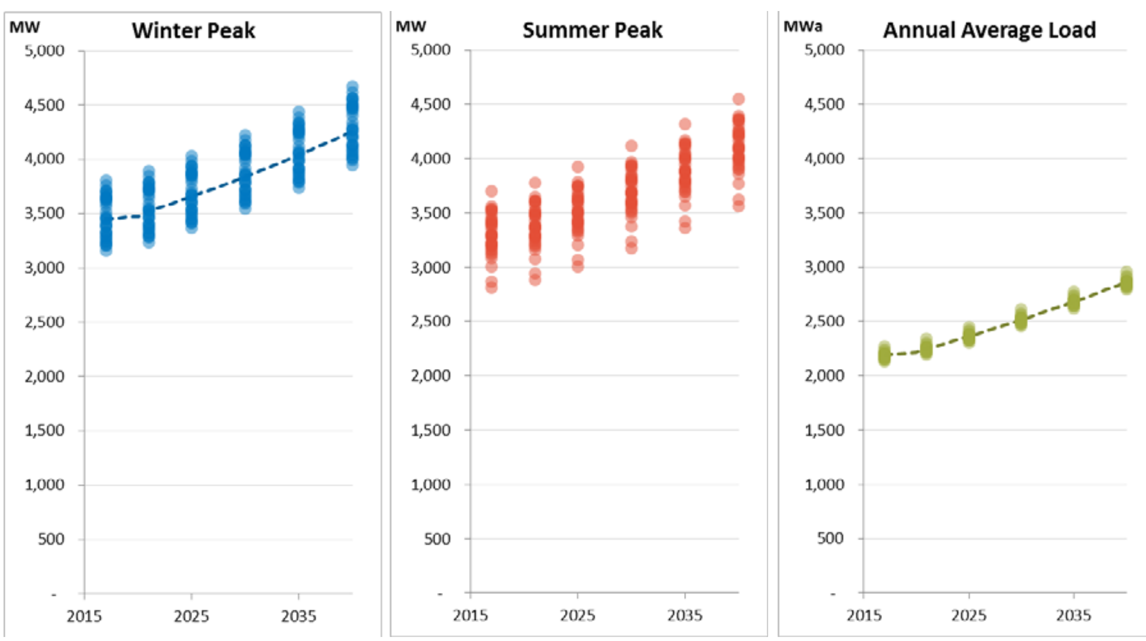
4.1.5. *Uncertainty*

PGE's load forecast appropriately considers uncertainty

PGE uses standard errors as the basis for establishing realistic high and low forecast scenarios ("jaws") and considers additional stochastic risk in the next stage of the IRP analysis, the Renewable Energy Capacity Planning (RECAP) analysis. The high and load forecast jaws expand over time to reflect the greater uncertainty in the long-term due to potential for compounding effects of market shifts and innovation. PGE's jaws approach has been used for a number of years. There are a number of alternative approaches for constructing bounds on the load forecast and the Company is open to working with Staff to develop new criteria to evaluate the uncertainty inherent in its load forecast for the next IRP cycle.

Weather is the single largest driver of load volatility, particularly with respect to seasonal peak demand. Uncertainty with respect to weather is incorporated in the IRP analysis through the RECAP model, which uses thirty-five years of annual load shapes based on historical weather data to characterize the loss of load expectation (LOLE) for each portfolio in each year. Incorporating these weather-driven load shapes into the RECAP analysis ensures that the capacity additions made in each IRP portfolio maintain resource adequacy across a distribution of potential weather conditions that is broader than the weather distribution reflected in the 1-in-2 year represented by the load forecast. **Figure 2** summarizes this weather-driven variability in RECAP for a set of modeled years. Each dot represents the winter peak, summer peak, or annual average load associated with one of the modeled weather years and the dashed line represents the Reference Case forecast.

FIGURE 2. Annual load statistics across weather years modeled in RECAP



4.1.6. *Direct Access Assumption*

PGE does not speculate on the future direct access activities of its customers.

Staff asked PGE to provide further justification and evidence for its assumptions of no new direct access customers.[79] PGE's load forecast assumes no new direct access customers and, consistent with IRP Guideline 9, assumes all long-term (five-year) direct access customers will remain on direct access. PGE does not have any information on which to base a prediction of how many, if any, customers will opt for direct access. Customer service elections to and from direct access are individual customer decisions made on the basis of a number of factors unique to each customer. In addition, PGE does not have access to information about terms being offered by third-party Electricity Service Suppliers that would inform any predictions concerning future new direct access customers. Therefore, PGE's forecast assumption regarding direct access customers is based on the service elections known at the time of the load forecast.

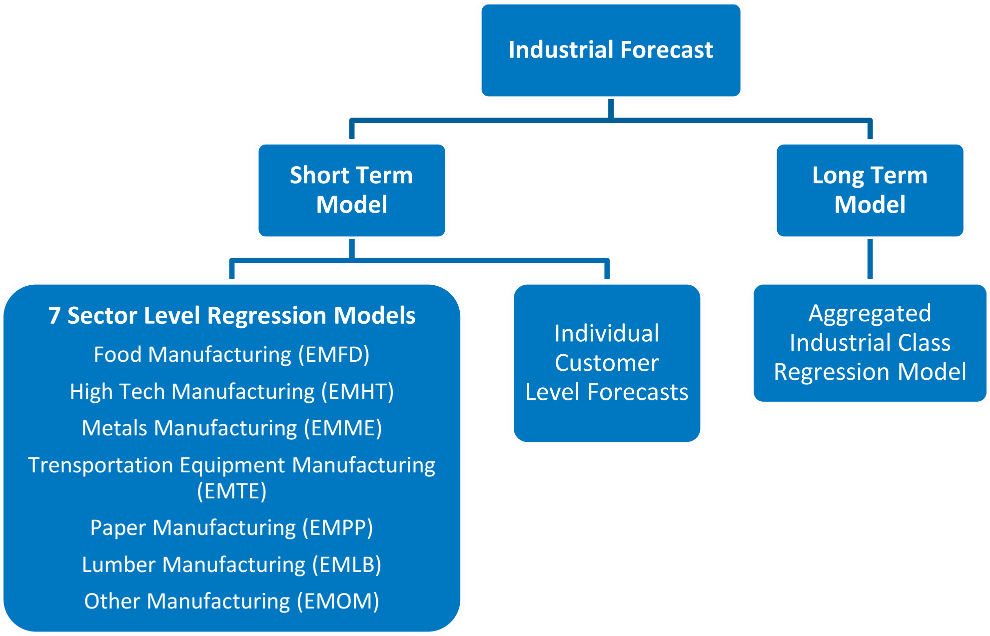
4.1.7. *Industrial Sector Models*

PGE implemented Itron's recommendations concerning industrial load growth.

Staff requested that PGE "adjust post-2021 industrial load growth forecasts by sectors to those levels recommended by Itron and share the results with Staff."[80] Staff's requested adjustments to industrial load post-2021 is inconsistent with the load forecast approach, as the sector-level models are used only in the short-term models. In this case, sector-level models are used to forecast only years up to 2021. The recommendations Itron made regarding the short-term sector level models, therefore, are irrelevant in application post-2021. **Figure 3** illustrates PGE's industrial model approach.

[79] Staff at 9.
[80] Staff at 9.

FIGURE 3: PGE'S INDUSTRIAL MODEL[81]



PGE implemented Itron's recommendations for the manufacturing models in the short-term load forecast. Itron recommended flat forecast models (i.e., models with indicator variables, such as seasonal variables, but no economic variables) for two of PGE's seven manufacturing models (EMME and EMPP[82]) and provided recommended drivers, sometimes including several alternative specifications, for the other five models. In the IRP load forecast, PGE adopted flat forecasts for the recommended segments as well as two additional segments (EMHT and EMLB), in total estimating flat forecasts for four of its seven short-term manufacturing models through 2021. Since large customers are excluded from the sector level manufacturing models, these groupings are small in size. These four models, combined, comprise approximately 10% of PGE's industrial load (or 50 MWa). For the additional three manufacturing models, EMFD, EMTE and EMOM, PGE incorporated the following recommendations as provided by Itron:

- Food Manufacturing (EMFD) -- PGE shortened the estimation period to begin in 2005 and included a cooling weather variable as well as total non-farm employment as an economic driver;
- Transportation Equipment Manufacturing (EMTE) -- PGE shortened the estimation period to begin in 1999 and included transportation equipment manufacturing employment as an economic driver;

[81] **Figure 3** is provided as an illustrative, simplified, example of PGE's approach. The short-term manufacturing sector models do not precisely feed into the long-term industrial model; rather the customers are allocated based on their service voltage level to secondary, primary or sub-transmission. The long term industrial model is comprised of a primary regression model (Revenue Class 5) and a flat sub-transmission service outlook (Revenue Class 4).
[82] *See* **Figure 3** for definitions of PGE's Manufacturing sector groupings

- Other Manufacturing (EMOM) -- PGE added total non-farm employment as an economic driver.

4.1.8. *Large Customer Forecasts*

At Staff's request, PGE performed a sensitivity analysis for certain individual customer forecasts.

OPUC Staff suggests that PGE use 15-year average historical growth rates of the large individually-forecasted customers as an alternative to PGE's pragmatic customer forecasts, which are used in the five-year time horizon.[83] PGE applied Staff's requested approach as a sensitivity case, using average growth rates from 2001-2016 for the 16 of its 28 individually forecasted customers with a 15-year history, to individual customer level loads beginning in 2017. The result of this approach is an increase of 5.6 MWa to industrial loads in 2021.[84] PGE notes that the time period assumed in this approach is arbitrary and that OPUC Staff does not provide guidance on how to estimate loads for the other 12 individually forecasted customers who have a shorter history, and for whom taking a similar approach would result in extremely high growth rates associated with new customer ramping.

PGE creates individual customer forecasts for its large customers because the load for these customers is highly sensitive to market trends and corporate strategic plans. Growth rates for these customers often diverge from long-term trends—e.g., declining in reaction to market competition or increasing with the expansion of facilities. Much of this insight is only available in the near-term, which is why PGE reverts to the long-term, top down, revenue class model for the post-2021 period.

4.1.9. *Distributed Renewables*

PGE includes impacts of distributed renewables implicitly in its load forecast models.

CUB is concerned with how future market transformation is integrated into the load forecast, particularly with respect to community solar and distributed rooftop photovoltaic power (PV). While there are many items influencing electric demand, inflection points, particularly in response to technological advancement, are difficult to predict. PGE's load forecast does not attempt to individually model end-uses such as electric vehicles or rooftop PV. Some levels of adoption are embedded within the forecast, as it is based on recent years' historical data. PGE also uses the high and low jaws scenarios to encompass a range of possible outcomes where changes occur at different rates or with load impacts that depart from the baseline forecast.

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[83] Staff at 9.

[84] The results of this analysis are included in **Confidential Attachment F**, Individual Customer Forecast Sensitivity, and provided under Protective Order No. 16-408 to Commission Staff only.

4.2. Capacity Adequacy and Contribution

PGE's 2016 IRP capacity need assessment is based on sound industry practices. The capacity need is primarily driven by expiring contracts and resources, including the need to replace output from the Boardman plant.

PARTIES' COMMENTS:

Staff believes the Company's methodology for assessing capacity adequacy and contribution is sound and reasonable and that the RECAP model used by the Company was an "excellent choice."[85] ODOE also supported PGE's reliance on the RECAP model to characterize the capacity need in the 2016 IRP.[86] ICNU, however, believes that RECAP is not appropriate for Northwest utilities.[87]

While Staff characterized the system assumptions in RECAP as generally reasonable, they expressed concern regarding assumptions around market reliance, contract renewals, energy imbalance market (EIM), and the target loss-of-load expectation (LOLE).[88] Specifically, Staff compared the assumption of 200 MW of market reliance in non-summer peak hours to PacifiCorp's higher market reliance assumptions and recommended that PGE include 200 MW of market reliance in summer peak hours; said that contract renewals should be assumed in evaluation of the capacity need; expressed interest in more discussion of the ability to reduce reserve obligations through the EIM; and proposed that long-term resource adequacy should target an LOLE of 23.3 hours rather than 2.4 hours, on the basis that PGE assumes that capacity needs through 2020 can be met through mid- and short-term planning and procurement.[89]

ICNU claimed that PGE assumed too large of a planning reserve margin (PRM) and that a 12% PRM with an assumption of 300 MW of market access in winter on-peak hours would result in a capacity need of 243 MW.[90] ICNU also requested additional information about the capacity contribution of wind and solar resources.[91]

NIPPC claimed that the capacity need is inflated by an artificial constraint on market access.[92]

PGE's RESPONSE:

PGE notes that some stakeholder comments are related to assumptions about resources available to fill the capacity need, rather than identification of the need. For example, Staff recommends that PGE include contract renewals that are not yet executed in its resource stack when evaluating capacity need. PGE seeks to clearly delineate between the identified need and the actions that can be taken to fill that need. PGE has defined the capacity need identified in the IRP as the capacity needed after accounting for existing resources, executed contracts, constrained

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85 Staff at 21.
86 ODOE at 2.
87 ICNU at 3-4.
88 Staff at 21.
89 *Id.* at 21-22.
90 Mullins at 4-6.
91 *Id*. at 7.
92 NIPPC at 26.

spot market contributions, and the identified actions for energy efficiency, demand response, and dispatchable standby generation at a snapshot in time based on the IRP analytical process. Additional resource actions taken after this snapshot, including those pursued through short- or mid-term activities or the bilateral negotiations discussed in Reply Comments **Section 2.5** do not change the need identified in the IRP. Consistent with the Action Plan, these activities serve to fill a portion of the identified need.

Assumptions that would impact the capacity need identified in the IRP include the resource adequacy standard, the load forecast, and the spot market reliance assumptions. These are discussed below. In addition, PGE provides an informational capacity analysis that uses the December 2016 load forecast and Qualifying Facilities (QF) contracts signed through the end of 2016 to show an example of how PGE will account for the evolution of resource needs over time before issuing an RFP.

4.2.1. ***Methodology***

PGE uses sound capacity adequacy modeling.

Stakeholders and Staff expressed general satisfaction with the resource adequacy methodology employed in the 2016 IRP. The use of a stochastic LOLE model represents a significant improvement in resource adequacy modeling, specifically with respect to characterizing the nature of load excursion risks and renewable resource capacity contributions. PGE acknowledges that new methodologies may require new frameworks for understanding modeling inputs and results, and the RECAP analysis is no exception.

Mr. Mullins, commenting on behalf of ICNU, described RECAP as having a "black-box nature" and notes that it is "not easy to understand".[93] PGE agrees that RECAP requires discussion and explanation to understand; however, PGE argues that the model is far from a black box.

RECAP is an open source model. PGE provided the model, inputs, and outputs to stakeholders in PGE's Response to ICNU Data Request No. 013, making it possible for stakeholders to view the code behind RECAP. In addition to the material provided in responses to data requests and in the IRP, PGE discussed the RECAP analysis at multiple public meetings, including a presentation from E3 on August 13, 2015.

As variable resources have become an increasing part of the mix of resources, it has been necessary for more complex models to be adopted to assess both capacity need and flexibility challenges. Utilities and stakeholders need to adapt to be able to develop, operate, and review these models. PGE looks forward to continuing to working with stakeholders in future round tables and workshops to facilitate understandings of models.

PGE rejects ICNU's recommendation that RECAP is not an appropriate model for PGE's resource adequacy study. Mr. Mullins indicates that he believes that RECAP is not sufficiently

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[93] ICNU, Comments of B. Mullins at 3.

comprehensive and mischaracterizes the model as relying more on extrapolated data than on historical data.[94] PGE objects to these characterizations.

First, RECAP is a sophisticated model that allows for the easy use of significant quantities of historic data, capturing—among other items—correlation with load, forced outage rates, impacts of unit size, and declining marginal values. The model calculates the loss of load probability for each month/day-type/hour of a given test year (e.g., August, weekday, hour ending 18), allowing visibility into the seasonal and diurnal nature of need. Second, all models are subject to the quality of input data used and PGE's resource adequacy study used extensive historical data, as described in Section 5.1.3 of the 2016 IRP. The use of neural networks to "train" historical load behavior to more recent trends is common industry practice and is discussed in Reply Comments **Section 4.2.4**.

The methodology used in the 2016 IRP brings several improvements to PGE's IRP process, including the following:

- The study allows PGE to assess the capacity needed to achieve a resource adequacy standard based on a comprehensive loss of load study.
- The study allows PGE to apply a single model and data set to three steps in the IRP process (the capacity need assessment, the capacity contribution calculations, and portfolio risk assessments), improving the usefulness of the results.
- The method captures correlation with load, improving the ability to compare resources.
- The method captures declining marginal value, improving the ability to compare resources.
- The method incorporates portfolio effects, allowing PGE to assess the capacity contributions from candidate portfolios of different resources, improving the portfolio evaluation process.

PGE notes that this methodology is particularly important for addressing concerns raised by parties in the 2013 IRP regarding the methodology for assessing capacity contribution from variable resources.[95] Further, the methodology allows PGE to comply with OPUC Order No. 16-326, which requires the use of ELCC calculations or Capacity Factor approximations in future IRPs. (Renewable ELCC calculations are discussed in Reply Comments **Section 4.2.6**.)

In short, the resource adequacy methodology adopted by PGE for the 2016 IRP is rigorous, sophisticated, and transparent. Loss of load expectation analysis is not simple; however, PGE believes that the benefits far outweigh the challenges introduced by the complexity of the analysis.

[94] *Id.*
[95] Order No. 14-415, PGE's 2013 IRP Acknowledgement Order, at 13-14.

4.2.2. *Resource Adequacy Standard*

> ***PGE's LOLE standard is an appropriate metric to assess long-term resource adequacy to meet customers' demand.***

The LOLE metric of 2.4 hours per year used in the IRP is based on a widely used 1-in-10 reliability standard in the electricity industry. This reliability standard has been interpreted differently by various entities. Some entities have interpreted the standard as allowing for one loss-of-load event due to capacity inadequacy in ten years (resulting in an LOLE of less than 2.4 hours/year, if the event has an expected duration of less than 24 hours). Others, including PGE and PacifiCorp,[96] have interpreted the standard as no more than 24 hours of LOLE in ten years, resulting in a less conservative planning metric than the standard of one event in ten years. The 2016 IRP resource adequacy standard was discussed with Stakeholders at several public meetings, beginning with the August 13, 2015 meeting.

PGE notes that Staff's recommendation of using an LOLE metric of 23.3 hours per year, which would allow for nearly a full day of loss-of-load events each year on average, is substantially lower than any industry practice that PGE is aware of. PGE interprets Staff's proposal to set the LOLE to 23.3 hours as an attempt to define the identified capacity shortage as exclusive of Staff's estimate for the potential short- or mid-term procurement activities that the Company could undertake. PGE contends that the treatment of short- and mid-term procurement activities should be discussed in the context of resource options and the merits of the Action Plan, not in adjustments to the reliability standard. PGE also notes that the assumed availability of short- and mid-term capacity contract options in the 2018-2020 timeframe cannot necessarily be assumed for years after 2020, when regional resource adequacy assessments have indicated that the Pacific Northwest is likely to be capacity short without incremental resource actions. Regional Adequacy is discussed in Reply Comments **Section 4.3.4**.

4.2.3. *Planning Reserve Margin (PRM)*

> ***Planning reserve margins alone do not provide a meaningful comparison of resource adequacy assessments.***

PGE notes that the PRM metric is not an input to the capacity adequacy evaluation and has no bearing on the identified capacity need.

Mr. Mullins states that "the existing PRM has produced reasonable reliability in the Company's service territory for many years. Accordingly, the Company's proposal to increase the PRM is inappropriate."[97] Mr. Mullins also characterizes the PRM as "excessively high".[98] Similarly, ICNU dismisses the 2016 IRP PRM as a "solution in search of a problem" and suggests that it will materially increase customers' costs compared to the 2013 IRP PRM of 12%.[99] These

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96 *Id.*
97 ICNU, Comments of B. Mullins at 2-3.
98 *Id*. at 6.
99 ICNU at 22-23.

comments, however, are overly simplified conclusions that fail to recognize the limitations of PRM values alone in assessing resource adequacy, fail to recognize the differences that exist between the methodologies used in each IRP, fail to acknowledge that the capacity assessment for the 2016 IRP is not driven by achieving a particular PRM, and fail to note that the 2013 IRP estimated a very similar assessment of capacity need for 2021 as the 2016 IRP.

If PGE were to revert to the previous methodology and PRM, the summer capacity need identified would be approximately the same as the annual capacity need identified in the 2016 IRP.[100] The 2013 IRP capacity LRB estimated the need in seasonal peak hours. The capacity need assessment relied on a 12% PRM "rule-of-thumb" applied to the 1-in-2 seasonal peak load. Existing and contracted resources were assessed based on their expected seasonal peak capacity contribution. The summer resource stack is lower than the annual capacity value due primarily to temperature derations for some thermal plants and reduced hydro availability. In this methodology, wind and solar resources were attributed a 5% capacity value. The summer capacity need was identified by:

$$SummerNeed = SummerPeakLoad \times 112\% - SummerResources$$

If this methodology is applied to 2021, the resource need (after energy efficiency (EE), demand response (DR), and dispatchable standby generation (DSG) actions) is approximately 797 MW or 22 MW less than identified by the RECAP modeling. Though only 22 MW apart, these two methodologies would appear to be further apart if one only examines the differences in the PRMs (12% vs. 17%). This exercise demonstrates that a simple comparison of PRM values without an examination of the underlying system reliability is inadequate for evaluating the relative merits of one planning standard versus another. A similar conclusion regarding PRMs is found in a 2011 North American Electric Reliability Corporation (NERC) report, "By itself the expected Planning Reserve Margin cannot communicate how reliable a system is and whether it has sufficient resources to reliably meet customer loads."[101] PGE rejects the claim that the appropriateness of a resource adequacy assessment can be determined by comparing PRMs.

In response to a question by Commissioner Bloom at the February 16, 2017 workshop regarding whether or not the PRM is a result of additions of wind resources in 2018, PGE responds that it is not. The RECAP study used to determine the capacity need does not include a candidate 2018 wind resource. The only wind resources included are existing resources. The summary PRM shown in Table P-1 of Appendix P of the IRP was calculated from the same RECAP study as the identified capacity need and is therefore not impacted by a candidate 2018 wind resource.[102]

As stated previously, in the 2016 IRP, the resource adequacy model solves to achieve an annual reliability standard based on a LOLE, not a PRM. While a PRM provides no information

[100] Summer is selected because the gap between load and available resources is larger in summer months than winter months. While seasonal peak heuristics are not directly comparable to annual LOLE studies, the season with the larger gap is a better comparator to the annual need identified in an LOLE study.
[101] "Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning." North American Electric Reliability Corporation, March 2011, at 7-8. Accessed March 27, 2017: http://www.nerc.com/docs/pc/ivgtf/IVGTF1-2.pdf.NERC.
[102] In Table P-1, the PRM is labeled as the TRM% (Total Reserve Margin).

regarding the reliability of a system, PGE has shown than the 2021 capacity shortage identified using the LOLE approach in the 2016 IRP is close to the capacity shortage identified using a 12% summer PRM approach, indicating that despite methodological advances, the resource adequacy findings in the 2016 IRP do not represent a significant departure from prior IRPs. Furthermore, planning to a reliability-based standard such as an LOLE is a widely accepted industry practice.[103] This framework also allows for a more refined assessment of the capacity contribution of candidate resources, improving the resource evaluation and selection processes.

4.2.4. ***Load***

The stochastic treatment of load in RECAP is reasonable.

In preparing the load data set for RECAP, E3 used extensive load and weather data to capture load behavior across a wide range of weather conditions. This study used 35 years of historical weather and load data.[104] PGE discussed the treatment of load in RECAP in several public meetings, including the August 13, 2015 presentation from E3.

Mr. Mullins mischaracterizes the use of neural networks in preparing the input data for RECAP, implying that it makes use of extrapolation instead of historical data.[105] PGE assumes that Mr. Mullins is referring to the development of the load input. As is common practice in probabilistic reliability studies, RECAP makes use of historical weather and load data to develop a data set that captures the frequency and impact of weather on load. In order to capture the changing nature of load's response to weather, the earlier years in the history are "trained" to the behavior of the more recent years. This is also a common industry practice for probabilistic loss of load studies, which must capture a wide range of conditions to provide useful information and often need to adjust for changing behavior over time. A study which only contemplates the 1-in-2 load forecast provides insufficient information for determining capacity adequacy. In the case of the PGE study, E3 performed this analysis using a neural network.

Mr. Mullins expressed concern about a difference between the peak load forecast in RECAP and the peak load forecast in the Company's load and resource balance.[106] PGE notes that this was addressed in PGE's Response to ICNU Data Request No. 013.[107] RECAP uses a different statistical baseline for scaling hourly load shapes than is used in developing the winter peak demand. In particular, the annual 1-in-2 peak is larger than the winter 1-in-2 peak for a system like PGE's, which may experience peak conditions in the winter or summer seasons. The Winter-to-RECAP Annual Peak scalar converts PGE's Winter 1-in-2 Peak to a number that will ensure that RECAP appropriately adjusts the load shape in each year to meet both the forecast energy and peak demand. E3 performed the calculation of the scalar.

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[103] NERC, "Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning", at 6 and 9.
[104] PGE's 2016 IRP, Section 5.1.3 at 117.
[105] ICNU, Comments of B. Mullins at 3.
[106] ICNU, Comments of B. Mullins at 6.
[107] File "E3 RECAP Inputs 2016IRP_CONF.xlsm", worksheet "Peak and Energy Forecast".

4.2.5. *Energy Imbalance Market*

PGE's capacity need is not reduced by the Energy Imbalance Market.

The energy imbalance market (EIM) does not, and is not intended to, provide participants with firm capacity resources. Participation in an energy imbalance market provides only intra-hour energy-only optimization according to the system conditions unique to each operating interval. These conditions vary from interval to interval according to the real-time, voluntary decisions of EIM participants to offer generating capability and transmission transfer capacity to the market, and according to the EIM operator's assessment of whether each EIM participant has demonstrated adequacy with sufficiency tests on their own systems.

Questions regarding the role of the EIM in the context of participants' resource adequacy were recently addressed at the CAISO EIM Governing Body Meeting on February 1, 2017. According to *RTO Insider*, an industry news organization, Mark Rothleder, Vice President for Market Quality and Renewable Integration at CAISO, stated at this meeting that "the balancing area, in order to maintain their reliability, can't rely on EIM to avoid capacity upgrades that they may need to meet their [integrated resource plan], resource adequacy or flexible capacity needs."[108] Rothleder's comments are consistent with the language in Section 5.3.4 of the 2016 IRP, which explains that the EIM sufficiency tests will require PGE to ensure sufficient resources available to be dispatched on its system prior to each time step. This holds true for the CAISO's assessment of its own capacity needs as well, as is demonstrated by the fact that the presence of EIM transfers does not factor in to the CAISO's Flexible Capacity Needs Technical Study.[109]

Consistent with guidance from CAISO and the experience of EIM participants, PGE does not include any adjustments to its traditional capacity need or its flexibility adequacy evaluation associated with participation in the EIM.

4.2.6. *Renewable Effective Load Carrying Capabilities (ELCCs)*

PGE used RECAP to calculate renewable capacity contributions.

In Table P-1 of Appendix P in the IRP, PGE provided the combined capacity contribution for existing wind and solar resources for 2017-2040.[110] The contribution varies over time as both the size and the composition (wind versus solar) of the existing renewable resources vary year to year. This represents the quantity of annual capacity that can be avoided while achieving the annual LOLE standard. PGE notes that the renewable resources and the annual capacity do not reduce LOLE in the same hours of each month, but rather achieve the same annual reduction to LOLE. The renewable capacity contribution should not be interpreted as the contribution during the winter or summer seasonal peak hours. The annual ELCC is equal to the ratio of the capacity

[108] https://www.rtoinsider.com/caiso-eim-capacity-38062/
[109] http://www.caiso.com/Documents/Agenda-Presentation-FlexibleCapacityNeedsTechnicalStudyProcess.pdf
[110] Wind and solar contracts executed through May 31, 2016 are included in the modeling of existing resources. See Section 5.1.3 of the IRP.

contribution to the total installed capacity. The ELCC values for the existing wind and solar resources are shown in **Table 10** below for selected years.

TABLE 10. ELCC of existing and contracted renewables

Year	Installed Capacity (MW)	RECAP Capacity Contribution (MW)	Average ELCC (%)
2021	1,041	176	16.9%
2025	1,040	177	17.1%
2030	1,016	170	16.7%
2035	898	138	15.4%
2040	804	106	13.2%

PGE also calculated the marginal ELCC values for three candidate renewable resources in increments of 100 MW resource additions using the RECAP model. This study examined resource types in isolation in order to characterize their declining marginal value. The information was presented at the August 17, 2016 public meeting and included in the 2016 IRP in Figure 5-11.

For portfolio construction, PGE created portfolio specific RECAP runs to account for the capacity contributions of all incremental resource additions (excluding Generic Capacity). These runs captured portfolio effects (such as the combined benefit of wind and solar being greater than their individual contributions), declining marginal value, load correlation, and more. Generic Capacity was then added to each portfolio to fill the remaining capacity need identified by RECAP.

Accordingly, PGE does not assign an ELCC to each variable resource option in IRP portfolio construction, but the results of the RECAP modeling can be used to calculate an ELCC for a portfolio of variable renewables by testing portfolios with and without the renewables. The example shown in **Table 11** considers the ELCC of incremental renewables in the *RPS Wind 2018* portfolio. The capacity contributions identified by running RECAP with and without the wind additions in the *RPS Wind 2018* portfolio are listed in the table below.

TABLE 11. ELCC of new wind additions in *RPS Wind 2018* Portfolio

Year	Installed Capacity (MW)	RECAP Capacity Contribution (MW)	Average ELCC (%)
2021	515	59	11.5%
2025	628	71	11.3%
2030	755	83	10.9%
2035	2,511	176	7.0%
2040	3,074	202	6.6%

This example isolates the impact of wind resources in the portfolio and finds that as more wind resources are added to the system, the ELCC of the portfolio of wind additions drops. The declining marginal ELCC of both wind and solar resources are discussed more fully in Section 5.1.5 of the 2016 IRP.

4.2.7. *Annual vs. Seasonal Assessment*

> ***PGE's resource adequacy study identifies the quantity of need based on an annual resource; however resources with different seasonal or hourly availability can contribute to meeting the capacity need.***

In response to comments from Commissioner Savage at the February 16, 2017 workshop, this section provides further discussion about annual versus seasonal need.

PGE acknowledges that using an annual reliability standard adds complexity to the resource adequacy assessment and requires new ways of understanding and visualizing the identified need compared to a heuristic seasonal peak hour analysis, particularly in a system with two seasonal peaks.

The RECAP model assesses PGE's LOLP in each month/day-type/hour (e.g., August, Weekday, Hour Ending 6 p.m.). Figure 5-3 in the 2016 IRP is a heat map of PGE's LOLP in 2021 after accounting for capacity contributions from the planned actions for EE, DR, and DSG, but prior to additional RPS or capacity resources. The annual LOLE is 253 hours.

In order to achieve the resource adequacy standard of 2.4 hr/yr., additional resources must be added. RECAP calculates the capacity need by adding a resource that is available in all months and hours.[111] For the 2016 IRP assessment, 819 MW of this annual resource was needed to achieve the 2.4 hr/yr. standard. This, however, does not mean that the only way to meet the standard is through the addition of 819 MW of an annual resource. Resources with different capacity contribution profiles can contribute to reducing the annual LOLE hours. PGE notes that two resources can achieve the same reduction to the annual LOLE while having significantly different impacts to specific hours.

When constructing portfolios to achieve the annual LOLE standard, RECAP accounted for the differing seasonal capacity contributions of resources. For example, the addition of solar resources captured the higher contribution in summer hours and lower contribution in winter hours and the addition of combined-cycle units captured the lower summer contributions due to the temperature impacts on available capacity. Adding these resources reduces the remaining quantity of annual resource needed to achieve the annual LOLE standard. The ability to capture the contribution profile of each resource type improves the resource evaluation process. **Section 6.1** of these Comments discusses portfolio construction.

In order to provide additional insight into the seasonal nature of PGE's need and the potential value to seasonal capacity products, PGE included a simplified seasonal product analysis in

[111] Adjusted for a forced outage rate.

Section 5.1.4 of the 2016 IRP. One observation from this exercise is that a summer on-peak product makes a larger reduction to the annual LOLE than a similarly sized winter on-peak resource. This is shown by the higher ELCC values of summer products in Figure 5-6 of the 2016 IRP. As stated previously, the ELCC is an annual value and should not be interpreted as a seasonal peak contribution.

4.2.8. *Staff and ICNU Assessments*

Staff's resource adequacy assessment conflates resource need with actions. ICNU's assessment has several material flaws.

In the February 16 workshop, Commissioner Bloom noted the substantial differences among the results of the capacity need assessments conducted by PGE, Staff, and ICNU and requested an explanation for the differences. This section summarizes the major differences among the three analyses in response to the request.

The three assessments are summarized below in **Table 12**. The major drivers for the different quantities of capacity shortage identified are differing assumptions about: resource adequacy standards, market availability, load, and renewable contributions.

TABLE 12: Comparison of capacity assessments

	PGE	Staff	ICNU
2021 Capacity Need	819 MW annual	478 MW[112] Annual	243 MW winter peak only
LOLE	2.4 hr./yr.	23.3 hr./yr.	Not provided
Load	June 2015 Forecast w/ 35 years of weather data	June 2015 Forecast w/ 35 years of weather data	June 2015 Forecast Winter Peak reduced by ~98 MW
Market	200 MW Spot Market, excluding summer on-peak	200 MW Spot Market, excluding summer on-peak	~300 MW Front Office Transactions, winter
Renewable Contribution	RECAP ELCC	RECAP ELCC	10% Wind, winter 20% Solar, winter

[112] Staff's Response to PGE's Data Request No. 001, Confidential Attachment B.

Staff Assessment

Staff's assessment is based on the IRP RECAP model with the LOLE target adjusted to 23.3 hours per year. Staff indicates that this assumption was deemed reasonable because that was the IRP LOLE in 2019 prior to capacity actions and that the Action Plan addressed the 2019 need through short and mid-term contracts.

PGE rejects this recommendation. Staff conflates the resource adequacy assessment with actions to meet the identified need. In doing so, staff uses a resource adequacy target that is far below any industry standard for long-term planning. Resource adequacy need should not be identified based on a manipulated reliability metric. The determination of resource actions to fill the need, including the option to procure short and mid-term contracts, occurs after the need is identified. Furthermore, failing to properly assess the need through the use of a materially inadequate standard would provide false signals to the market and the region, create false perceptions of future costs, distort ELCC calculations, and impair resource evaluation.

ICNU Assessment

Unlike PGE and Staff, ICNU did not use a loss of load study to assess capacity need. ICNU's assessment examines only the winter peak hour.[113] PGE notes several issues with ICNU's assessment, including the following:

- Mr. Mullins elected to perform a single-season heuristic analysis of winter peak hour need. As such, the identified need is not directly comparable to the annual capacity values in PGE or Staff's assessments.
- PGE's capacity needs are not solely driven by the winter peak. In Section 5.1.4.1 of the 2016 IRP, PGE's seasonal capacity analysis indicated a higher ELCC value for a summer seasonal product compared to a similarly sized winter product, indicating the greater need in summer hours. This is due to a combination of factors, including an increase in summer peak load growth relative to winter peak load growth, seasonal reduction in hydro availability, and temperature derates for thermal plant capacities in the summer.
- Mr. Mullins' analysis assumed a winter peak load reduction of approximately 98 MW compared to the 2016 IRP. This reduction is based on calculations using the 2017 peak load forecast in UE 308 (2017 AUT). While PGE understands stakeholders' desire to include the most recent load information, the RFP process provides ample opportunity to adjust the amount ultimately procured, if necessary to account for load forecast and contract updates. In **Sections 4.1.2** and **4.2.9** of these Reply Comments, PGE provides additional information regarding the December 2016 load forecast and its impact on capacity need.
- Mr. Mullins' analysis assumed 300 MW of available Front Office Transactions. No justification was provided for this assumption. This is 100 MW greater than the quantity of spot market purchases assumed by PGE and Staff. Mr. Mullins' analysis

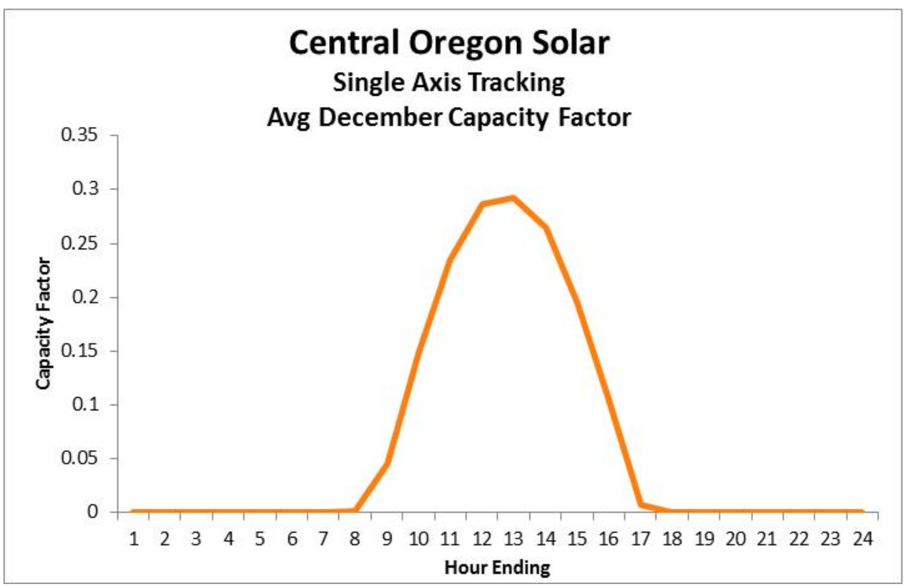
[113] ICNU, Comments of B. Mullins at 5.

appears to be conflating the spot market with short and mid-term purchases. Market assumptions are discussed in Reply Comments **Section 4.3**.

- PGE also notes that Mr. Mullins' analysis incorrectly described PGE's treatment of the spot market in RECAP, claiming that PGE "assumed that only 98 MW of market transactions would be available in 2021 to meet peak loads."[114] The RECAP modeling included 200 MW of spot market in all hours, except for on-peak summer hours. This hourly availability assumption resulted in an annual capacity contribution associated with spot market access of 98 MW. Mr. Mullins incorrectly attributes this annual capacity contribution to the winter peak hour, while PGE's analysis assumes that the full 200 MW is available in winter on-peak hours.

- For wind and solar resources, Mr. Mullins' analysis attributed a 10% winter capacity contribution to all wind resources and a 20% winter capacity contribution to all solar resources. Mr. Mullins' analysis provided no support for these values. PGE has significant doubts about this assumption given the timing of the winter peak and the availability of solar. As shown in **Figure 4**, on an average basis, a solar resource in Oregon exceeds approximately 20% capacity factor in hours ending 10 through 15 while the PGE winter system peak occurs in hour ending 18 or 19, when the solar capacity factor is effectively 0%.

FIGURE 4. Central Oregon Solar December Capacity Factor[115]



- Regarding renewable capacity contributions, as summarized in OPUC Order No. 16-326, "ICNU states that approximation methods have the potential to create a wide range of capacity contribution values. ICNU recommends full ELCC studies and

[114] *Id.* at 6.
[115] Based on 2003-2014 irradiance data from the University of Oregon and 2006 irradiance data from the National Renewable Energy Laboratory (NREL).

states that the computational intensity is not as problematic as it once was because the utilities commonly develop and perform reliability studies in their IRPs to calculate planning reserve margins." PGE notes that Mr. Mullins' analysis did not conduct a full ELCC study, as recommended by ICNU.

For the reasons discussed above, PGE contends that the analysis provided by Mr. Mullins suffers from material flaws and does not provide a meaningful assessment of PGE's capacity need.

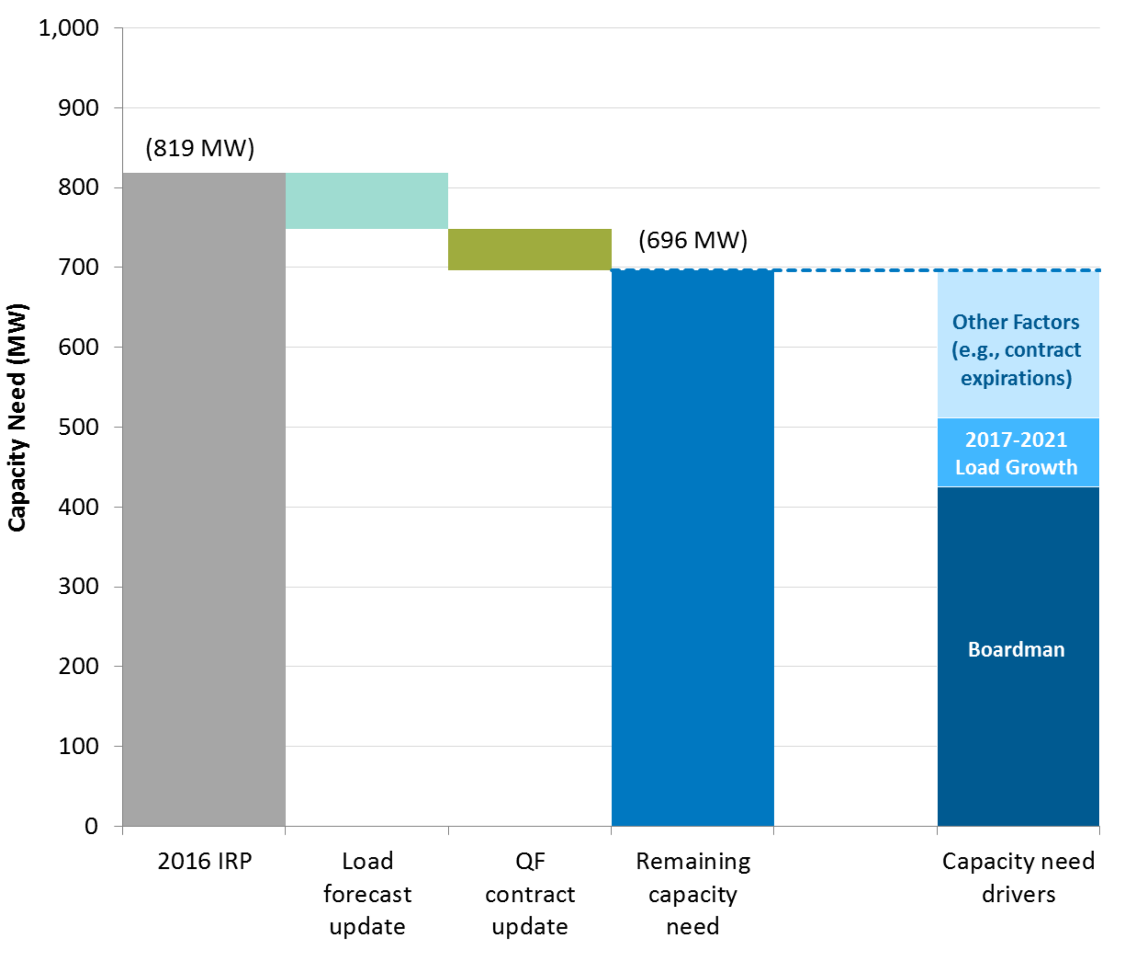
4.2.9. *Resource Adequacy Evaluation Updates*

> ***PGE continues to evaluate resource adequacy needs in response to updated load forecasts and recently signed contracts.***

To provide a tangible example of how PGE accounts for activities conducted after the IRP resource adequacy snapshot, PGE conducted a supplemental RECAP analysis. This analysis incorporated the December 2016 load forecast update described in **Section 4.1** and additional QF contracts that were executed between June 1, 2016 and December 31, 2016.[116] The analysis does not include the additional capacity acquired under the Wells contract, which was executed contemporaneously with the final preparation of these Reply Comments. PGE will provide an updated analysis showing the impact of the Wells contract. The supplemental RECAP analysis identifies 696 MW of remaining capacity need in 2021 after accounting for the load forecast and QF contract updates. **Figure 5** illustrates the relative impacts of the two updates on the capacity need. **Figure 5** also shows a breakdown of the drivers of the remaining capacity need: ceasing coal-fired operations at Boardman drives approximately 425 MW of the capacity need; forecast load growth between 2017 and 2021 contributes approximately 86 MW; and other factors, including contract expirations, drive the remaining 185 MW of capacity need.

[116] The 2016 IRP RECAP assessment included contracts executed through May 31, 2016. See Section 5.1.3.

FIGURE 5: Capacity Need Impact due to Load and Contracts



The capacity need expressed in **Figure 5** is based on the quantity of annual capacity needed to achieve the annual LOLE standard. As discussed previously, this is not the same as estimating the capacity need for seasonal peak hours. See Reply Comments **Sections 4.2.2** and **4.2.7**.

The capacity need identified in the IRP is primarily driven by resource retirements and contract expirations, not by growth in the load forecast. The assessment remains robust after accounting for the more recent information. PGE still proposes to issue one or more RFPs for capacity. The updated assessment will simply reduce the amount of capacity that PGE ultimately procures under the RFP(s).

4.3. Market Access

PARTIES' COMMENTS:

Several parties suggest that PGE should evaluate additional resources to meet PGE's capacity needs, specifically market purchases.[117] Some parties believe more explanation is needed to understand the nature of PGE's 2016 IRP assumptions regarding the availability of capacity through market purchases.[118] For example, Staff has difficulty in understanding PGE's assessment of the market depth of the Western Electricity Coordinating Council's (WECC) energy and capacity market.[119]

Staff believes that in the recent past PGE relied much more on the market than the IRP suggests it will in the future.[120] Staff cites PGE's August 2016 Investor Presentation as evidence that PGE limits future spot market purchases in the IRP to 200 MW out of reliability concerns while four years ago PGE was securing over 33 percent of its retail load needs through purchased power.[121] While Staff does not identify a reasonable limit for spot market purchases used to meet peak capacity needs, Staff does suggest that PGE's assumed limit is more conservative than PacifiCorp as evidenced "[i]n the 2017 PacifiCorp IRP General Public Meeting held September 22-23, 2016, [where] available market purchases in the west were revised down to 875 MW."[122]

NWEC claims that ". . . all modeling scenarios include a market limitation of 200 MW during all time frames across the year except summer peak times, which have no market availability." NWEC also expresses dissatisfaction in PGE's compliance with the OPUC Order No. 14-415 directive to include portfolios that maintain an open position.[123]

CUB is also concerned that PGE's IRP analysis does not allow for spot market purchases. CUB contends that "[b]y eliminating market purchases to meet the Company's load, PGE is likely ignoring a valuable option to creating a least-cost portfolio."[124] Like Staff, CUB references PGE's August 2016 Investor Presentation as evidence that PGE previously relied more heavily on market purchases in its portfolio.

PGE's RESPONSE:

PGE appreciates this opportunity to provide additional clarifying information regarding market access assumptions in the 2016 IRP. PGE notes that market access assumptions are different in the two key portfolio evaluation processes that occur within the IRP: resource adequacy and economic modeling of portfolio performance. As described below, PGE assumes unlimited access to market energy in its economic modeling of portfolios (i.e., AURORA modeling), allowing all portfolios to be short to the market on an average energy basis. However, in the resource adequacy evaluation, which specifically considers tail events and periods in which the

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[117] CUB at 4 and7; Sierra Club at 7-9; NIPPC at 27-78.
[118] ICNU Comments, Mullins at 3-4, 6; NWEC at 2-3.
[119] Staff at 23.
[120] *Id.* at 3.
[121] *Id.* at 23.
[122] *Id.*at 21.
[123] NWEC at 2-3.
[124] CUB at 7.

region may be capacity constrained, PGE limits the market access assumption to ensure that the Company maintains reliable operations. The following sections describe market access assumptions in both of these frameworks and provide additional discussion regarding the comparability of market assumptions across utilities and regional resource adequacy considerations.

4.3.1. *Market Access in Economic Evaluation*

> ***PGE assumes unlimited access to market energy in its economic modelling of portfolios and includes portfolios which maintain open positions.***

PGE conducts economic modeling of the variable costs and market revenues of portfolios using the AURORA model. In these simulations, PGE assumes that access to the wholesale energy market is unrestricted. This was discussed in public meetings, including the November 16, 2016 Round Table.

Consistent with industry practice, the hourly loads and resource availability modeled in AURORA represent "typical" conditions (i.e., the modeling does not capture load excursions due to weather). The dispatchable resources dispatch economically to wholesale market prices and PGE's energy position is balanced in each hour through market energy purchases or sales. There are no restrictions to the quantities of purchases or sales. In almost all portfolios, PGE maintains a net open position to the energy market on an annual basis. This meets the requirement set forth in OPUC Order No. 14-415 to evaluate portfolios with an open position.[125] The magnitude of the open position varies by portfolio and future. For example, the portfolio *Wind 2018* has a larger open position than the portfolio *Wind 2018 Long* and the futures with high load have larger open positions than the futures with reference or low load. This market exposure impacts the performance of each portfolio across the cost and risk metrics in portfolio scoring.

PGE also notes that AURORA does not differentiate between the timeframes over which transactions may occur for market purchases or sales of energy. Market purchases and sales in AURORA could therefore be interpreted as the net energy position associated with energy purchases and sales from year-ahead transactions all the way down to the spot market. Importantly, market access assumptions in AURORA do not represent an assessment of the quantity of capacity available to meet PGE's needs under constrained conditions nor do market energy transactions in AURORA represent the procurement of firm capacity to meet PGE's resource adequacy requirements.

The energy market modeled in AURORA is a reasonable simplification of regional wholesale markets for estimating annual variable operating costs and market revenues for long-term planning.

[125] OPUC Order 14-415, page 6.

4.3.2. *Market Access in Resource Adequacy Evaluation*

PGE's assumptions concerning reliance on the spot market in resource adequacy assessments are reasonable.

Market access assumptions in PGE's resource adequacy evaluation are more narrowly defined as the assumed availability of market power in the hour-ahead under capacity-constrained events. For a given event, the availability of market power will depend on the season, the geographical extent of the conditions that cause the shortage, the available transmission during the event, and several other market factors. It is difficult to quantify the depth of the market and PGE's access to the market under these conditions. The ability to forecast future availability based on historical events is further challenged by changes to system resources. There is no industry-standard approach to developing market reliance assumptions in resource adequacy studies. PGE therefore relied on the real-time experience and professional judgement of its power traders. This experience and judgment indicates that it is reasonable to assume 200 MW of spot market purchases will be available in all hours except summer peak hours and 0 MW of spot market purchases available in summer peak hours.

The Northwest Power and Conservation Council (Power Council) applies similarly structured constraints to market access in its regional resource adequacy modeling. For example, in the Pacific Northwest Power Supply Adequacy Assessment for 2021, the Power Council assumed different levels of available generation from Independent Power Producers (IPP) within the Northwest and different import capabilities into the Northwest from California depending on the season and time of day.[126] While the assessment assumes 2,943 MW of available capacity from IPPs in the region and 3,000 MW of available imports from California in winter off-peak hours, it assumes no available imports from California and only 1,000 MW of capacity from Northwest IPPs in summer on-peak hours due to competition with utilities in California and the Southwest. This seasonal swing of nearly 5,000 MW in market access highlights both the challenge in incorporating spot market access in resource adequacy evaluations and the importance of capturing the constraints across the West that arise due to high loads in summer months traditionally experienced in California and the Southwest and increasingly experienced in the Northwest. Importantly, the Power Council study does not include an evaluation of the contractual obligations of IPPs in the region, so the availability of these resources to provide capacity to PGE in the short-term or to transact in the spot market is not guaranteed.

Contrary to Staff's and CUB's suggestions, the assumed availability of spot market purchases to meet peak capacity needs does not mark a major shift from PGE's recent long-term planning. The power purchases described in PGE's August 2016 Investor Presentation, which were referenced by Staff and CUB to argue that PGE is inappropriately limiting market access in the 2016 IRP, are not an indication of PGE's historical reliance on spot market purchases to provide resource adequacy. In their arguments, Staff and CUB conflate average energy market behavior (including mid-term and short-term energy contracts as well as spot market transactions) over the course of a year with spot market availability during the critical times that impact resource

[126] NWPCC, "Pacific Northwest Power Supply Adequacy Assessment for 2021," September 27, 2016. https://www.nwcouncil.org/media/7150591/2016-10.pdf.

adequacy. As described in Reply Comments **Section 4.3.1,** PGE imposes no limits on energy market purchases and sales in its economic evaluation of portfolio performance.

With respect to resource adequacy, the market access assumptions in the 2016 IRP are consistent with PGE's acknowledged 2013 IRP. PGE's 2013 IRP states that "it is not prudent to assume availability of wholesale spot market power during the peak WECC summer months… However, for the remainder of the year, we assume moderate availability of market power. For years prior to 2019, we assume that 300 MW will be available in all non-summer hours. This drops to 200 MW beginning in 2019."[127] The tightening of spot market availability in the region discussed in the 2013 IRP remains a concern due to continued resource retirements in the region. Regional resource adequacy is discussed further in Reply Comments **Section 4.3.4**.

PGE notes that in addition to the spot market availability assumed in the IRP, PGE is also exposed to the risk of spot market availability for ESS load. While ESS load is not included in PGE's long-term planning, PGE remains the provider of last resort for all ESS customers. See Section 4.1.6 in the 2016 IRP.

4.3.3. *Comparability Across Utility Assumptions*

PGE's IRP spot market access assumptions are not interchangeable with PacifiCorp's Front Office Transaction assumptions.

PGE's assumptions regarding spot market availability are not interchangeable with PacifiCorp's Front Office Transaction assumptions cited by Staff. The PacifiCorp slides referenced by Staff make clear that the "available market purchases" assumed by PacifiCorp reflect 'Front Office Transactions' executed on an annual basis. PacifiCorp's Front Office Transactions include short-term and mid-term market physical purchases made one to three years ahead of need, in addition to spot market access. PGE considers spot market availability separately from short or mid-term capacity availability; with short and mid-term products treated as potential resource options. PGE discusses capacity products in Reply Comments **Section 5.3**.

Furthermore, PGE and PacifiCorp have significantly different systems, making it unreasonable to assume that an estimate made by one utility is applicable to the other. PacifiCorp's load is significantly larger than PGE's and is spread across a larger physical area, achieving greater weather diversity and time-of-day diversity compared to PGE. PacifiCorp also has access to a wider range of wholesale markets than PGE.

PGE notes that in the September 2016 presentation referenced by Staff, PacifiCorp examined four regional studies and commented that "[t]he studies differ in some details, but in general forecast that Pacific Northwest energy and capacity surplus will become deficit around 2021 . . . [PacifiCorp] will evaluate a sensitivity case that assumes reduced Front Office Transaction access to inform acquisition path analysis."[128]

[127] 2013 IRP Page 190
[128] PacifiCorp, 2017 IRP, Public Meeting #4, September 22-23, 2016, Slide 33.

4.3.4. *Regional Resource Adequacy*

Multiple regional assessments forecast a capacity shortage in 2021.

PGE does not conduct a regional resource adequacy evaluation in the IRP. Instead, PGE relies on the evaluations of other regional entities for broad guidance concerning the resource adequacy of the Pacific Northwest region. In particular, PGE looks to the Power Council's supply adequacy assessments, which identify the capacity needed in the region to meet a region-wide loss of load probability (LOLP) standard of 5%. In its Pacific Northwest Power Supply Adequacy Assessment for 2021, the Power Council identified an LOLP of 10-13% in 2021 if the Power Council's energy efficiency targets are met and no incremental resource additions are made.[129] The Power Council identified the retirement of Boardman and Centralia 1 coal plants in December 2020 as key drivers of the capacity shortage. The identified range depends on the uncertainty in the retirement date of Colstrip 1 and 2, which may occur during or prior to 2022. To achieve the target LOLP of 5% in 2021, the Power Council identified a capacity need of nearly 1,400 MW in the region.[130] Because the Power Council resource adequacy assessment does not account for all of the constraints that may impact the ability of a utility to secure firm capacity resources (e.g., contractual obligations related to capacity and/or transmission), capacity shortages faced by Northwest utilities in aggregate may exceed the shortages identified in the Power Council's assessment.

Similar findings regarding regional capacity adequacy in 2021 have been described by BPA and PNUCC. In its 2016 Pacific Northwest Loads and Resources Study, BPA identified a January capacity shortage between 1,755 MW and 4,707 MW in 2021 under critical water conditions, depending on assumptions regarding uncommitted IPP generation.[131] PNUCC identified a Winter Peak shortage of between 1,088 MW and 4,088 MW in 2021, depending on IPP assumptions.[132]

4.4. Dispatchable Capacity Need

PGE incorporated a 375-500 MW minimum dispatchable capacity constraint into the Action Plan based on detailed modeling of flexibility-related operating constraints under a wide range of conditions and for a large number of potential resource mixes. Below, PGE addresses comments from Staff and NIPPC on the quality of the REFLEX modeling exercise and the nature of the dispatchable capacity need.

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[129] NWPCC, "Pacific Northwest Power Supply Adequacy Assessment for 2021," September 27, 2016. https://www.nwcouncil.org/media/7150591/2016-10.pdf.

[130] Assuming that Colstrip 1 and 2 are unavailable in 2021.

[131] BPA, "2016 Pacific Northwest Loads and Resources Study," December 2016, Page 36, https://www.bpa.gov/power/pgp/whitebook/2016/2016-WBK-Loads-and-Resources-Summary-20161222.pdf.

[132] PNUCC, "Northwest Regional Forecast of Power Loads and Resources, 2017 through 2026," April 2016, http://www.pnucc.org/sites/default/files/file-uploads/2016%20NRF%20Final.pdf.

PARTIES' COMMENTS:

OPUC Staff "believes conceptually that the way the REFLEX model attempts to identify flexible resource needs is reasonable," but expresses the desire for PGE to conduct additional modeling that would allow for purchases at market prices rather than the penalty prices employed in the REFLEX analysis.[133] Staff also questions the extent to which early RPS action may drive the dispatchable capacity need, stating that "Staff believes it is possible that portfolios with greater levels of unbundled RECs could reduce the need for flexible capacity, and may prove to be lower cost than current portfolios."[134]

NIPPC claims that the REFLEX modeling exercise is fundamentally flawed, in part, because the heat rate curve used by the REFLEX model "contradicts information provided to PGE by Black and Veatch."[135] NIPPC provides an illustration of a heat rate curve claiming to be based on the reciprocating engine input data used in REFLEX.[136] NIPPC also disagrees with the minimum up and down times for reciprocating engines provided by Black & Veatch and used in the REFLEX study[137] and objects to the use of a constant available capacity for each month to model technology capabilities in REFLEX.[138] NIPPC also repeatedly states that the IRP analysis identified "no meaningful difference between these technology alternatives," referring to a combined-cycle gas turbine, a simple cycle gas turbine, and a reciprocating engine.[139]

PGE's RESPONSE:

4.4.1. *Flexibility Modeling Approach*

> ***PGE's third party flexibility study leveraged the best available modeling methodologies for flexibility adequacy and highlighted the need for continued efforts to incorporate operational analysis into future long-term planning exercises.***

There is no clear industry standard methodology for characterizing flexibility needs. The most promising methodologies involve multi-stage production simulation in highly time- and data-intensive modeling exercises. The REFLEX model is one such approach. Due to the computational complexity of these modeling problems, models like REFLEX rely on proprietary mathematical solvers and require substantial computing resources. For example, each portfolio evaluated in REFLEX for the 2016 IRP required one to three central processing unit (CPU) days of computation time to characterize the single test year (2021). PGE aimed to use the REFLEX analysis both to inform the IRP and to gain additional understanding about the nature of future flexibility challenges, but recognized that time and resource constraints would not allow for the detailed evaluation of every portfolio, year, or future.

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[133] Staff at 23.
[134] *Id.* at 21.
[135] NIPPC at 10.
[136] NIPPC at 13.
[137] NIPPC at 14.
[138] NIPPC at 14-15
[139] NIPPC at 9.

The Company knows of no analysis to date that has comprehensively evaluated the flexibility needs of a system across each of these dimensions. The most cutting edge modeling exercises in this space typically consider a single year or a small number of years, a single portfolio or a small number of portfolios, and a single future or a small number of sensitivities. The Company considers the REFLEX analysis to be an important step in improving the understanding of future flexibility challenges on the system, and recognizes that incremental improvements to the evaluation will continue to be important in future IRPs, especially as PGE attempts to more fully integrate flexibility considerations into portfolio evaluation.

Under the direction of PGE, E3 used its REFLEX model to test 25 different portfolios, which are listed in Table 5-5 in the 2016 IRP. These portfolios tested different renewable penetrations, renewable resources, and dispatchable resources. As mentioned by Staff, E3 utilized penalty prices to represent access to day-ahead resources to encourage the system to first rely on PGE resources to provide flexibility to the system before going to the market. The REFLEX analysis did not seek to evaluate the economic value of flexible resources. However, PGE does not disagree with Staff that lower cost operational solutions could be found on days in which PGE has access to additional power from the market.

The REFLEX analysis sought to evaluate the flexibility adequacy of the PGE portfolio. Low cost market access was excluded from this analysis, because PGE was primarily concerned with understanding how the PGE portfolio could respond on days that were constrained due to either capacity or flexibility shortages. Under these constrained conditions, PGE does not assume that it will be able to rely on the market to provide traditional resource adequacy or flexibility adequacy. However, PGE appreciates Staff's questions regarding the economics of flexibility-related issues and looks forward to further discussions about how to incorporate flexibility modeling into future IRPs.

One key finding of the study was that under a 25% RPS in 2021, the system required at least 400 MW of additional dispatchable resources to ensure that potential upward flexibility imbalance experienced in real-time did not greatly exceed modeled levels corresponding to the 2015 baseline portfolio. This finding was driven by:

- an increase in the renewable penetration between the 2015 baseline portfolio and the 25% RPS portfolios;
- Boardman ceasing coal-fired operations prior to 2021; and
- PGE self-integration of wind.

PGE did not request additional REFLEX simulations from E3 to separately evaluate the impacts of each of these factors due to time and resource constraints.

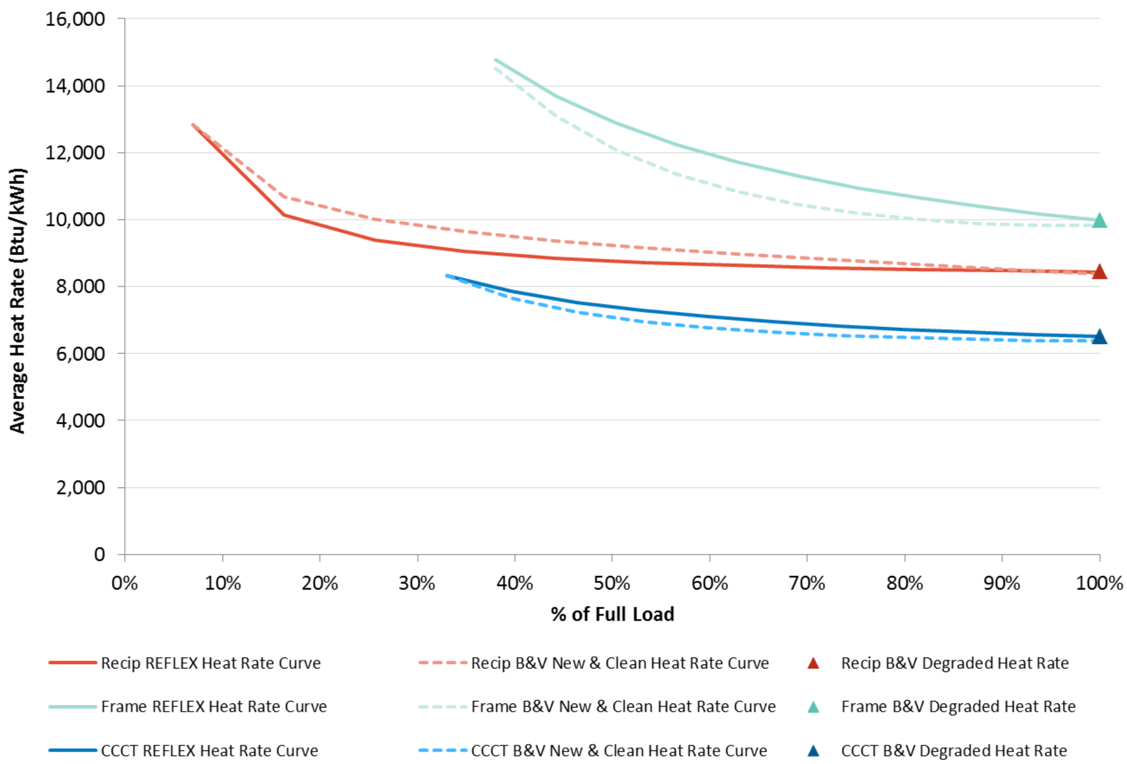
4.4.2. *Technology Characterization in REFLEX*

> ***The characterization of resource options in the REFLEX study was consistent with the available third party cost and performance data.***

PGE relied on Black & Veatch's "Characterization of Supply-Side Options," which is included in Appendix K of the 2016 IRP, to populate the parameters for new candidate resources in the dispatchable stack. PGE notes that NIPPC's statements regarding the heat rate assumptions used in the REFLEX study are incorrect. PGE was not able to verify the heat rate curves included on page 13 of NIPPC's Comments. The heat rate assumptions in REFLEX for new units were based on the fuel consumption at the minimum load and the fuel consumption at full load (after accounting for degradation), based on the heat rate curves for each technology provided by Black & Veatch. REFLEX assumes that fuel consumption between the minimum and full load points of a given unit is a linear function of the output. While the fuel consumption (in MMBtu) is approximated as a linear function of the output (in MWh), the average heat rate, which is equal to the fuel consumption divided by the output (in MMBtu/MWh), is not a linear function of the output (see **Figure 6** for example heat rate curves). The fuel consumption linearity assumption was incorporated into the modeling due to runtime considerations and the additional complexity introduced by non-linear fuel consumption functions. This is a common approach in production simulation exercises.

As shown in **Figure 6**, this linearity assumption results in average heat rates at set points between minimum load and full load that are slightly lower, or more efficient, than the heat rate curve provided by Black & Veatch for reciprocating engines. **Figure 6** also shows that the heat rate curves in REFLEX for CCCTs and Frame CTs are higher than those provided by Black & Veatch at set points between the minimum and full load points due to the curvature of those specific heat rate curves and the fuel use linearity assumption in REFLEX. Based on the data provided by Black & Veatch, the fuel use linearity assumption in REFLEX tends to slightly overestimate the competitiveness of reciprocating engines relative to CCCTs and Frame CTs.

FIGURE 6: Heat rate curves from Black & Veatch and REFLEX analysis



4.4.3. *Dispatchability Requirement*

The dispatchable capacity need identified for 2021 is an important constraint for the procurement of resources to meet the flexibility needs of evolving systems regardless of the near-term RPS strategy.

The Action Plan requirement that between 375 MW and 550 MW of the traditional capacity need be met with dispatchable resources reflects the findings of the REFLEX study. PGE notes that several of the drivers of the increased need for flexibility in the 2021 timeframe are independent of incremental RPS action. For example, the dispatchable fleets in the REFLEX study have similar aggregate sizes in the 2021 portfolios (without incremental action) and in the 2015 Baseline portfolio, despite load growth between 2015 and 2021. The minimum turn down capability (one indicator of system flexibility) is also approximately 90 MW higher (meaning less flexible) in the 2021 portfolio relative to the 2015 Baseline because coal plants (including Boardman) have relatively low turndown capabilities and Boardman is excluded from the 2021 portfolio. Furthermore, when considering the December 2016 load forecast described in **Section 4.1.2** and QF contracts signed through the end of December 2016, PGE's physical RPS position in 2021 may be as high as 21.2% of retail load[140] even without early RPS action. In addition,

[140] Under the assumption that all executed QF contracts result in successful projects, which is assumed throughout the IRP.

PGE will be moving to self-integration of its existing wind resources prior to 2021, placing additional importance on system flexibility. For these reasons, it is not appropriate to condition the minimum need for dispatchable capacity identified in the IRP on the outcome of a renewables RFP.

The dispatchability requirement is not tied to a specific technology because the REFLEX analysis found that the three dispatchable technologies tested (a combined-cycle combustion turbine, frame simple-cycle turbines, and reciprocating engines) had similar impacts on upward flexibility imbalances. Contrary to NIPPC's repeated claim that "PGE found no meaningful difference between flexible resources,"[141] the REFLEX analysis identified significant differences in how these technologies may be operated. While these operational considerations did not drive significant differences in the flexibility sufficiency on a portfolio basis, they certainly have implications for resource economics, a topic not explored in the REFLEX analysis. PGE provides additional information about the economic modeling of reciprocating engines in the context of proxy resources in **Section 5.3.1**.

The specific technical requirements required for the dispatchability of new resources is a subject for the RFP docket. PGE, however, makes the following general observations about the dispatchability requirement. First, the REFLEX analysis shows that the dispatchability requirement is approximate. The addition of 400 MW of dispatchable resources was not adequate to reduce flexibility violations to the levels observed in the 2015 baseline portfolio for any of the 25% RPS portfolios, regardless of the dispatchable technology. PGE therefore concludes that while additional dispatchable capacity beyond 400 MW may bring additional value to the system, failing to meet the dispatchable capacity requirement may introduce additional risks not quantified in the IRP.

The REFLEX analysis also suggests that resources can improve the flexibility of the system by directly providing high levels of flexibility, by interacting with other flexible resources on the system to improve the capabilities of the fleet, or through both of these mechanisms.

5. Resource Options

5.1. Energy Efficiency

PARTIES' COMMENTS:

CUB observes that historically, Energy Efficiency (EE) has outpaced the Energy Trust of Oregon's (Energy Trust) long-term projections and thereby, the Energy Trust's studies have "limited bearing on the impact EE will have 15, 20, or 30 years from now."[142]

NWEC advocates for "better approaches to modeling energy efficiency's potential contributions to cost and risks."[143] NWEC suggests a "trigger point" analysis to provide a price point up to which the future acquisition of EE provides both cost and risk benefits.[144]

[141] NIPCC at 7.
[142] CUB at 9.

NWEC also notes that PGE was unable to provide the underlying methodology and data behind the Energy Trust's EE supply curves.[145] NWEC recommends that, in the future, PGE should "publish the [Energy Trust's] underlying conservation potential assessment in conjunction with the IRP."[146]

Finally, NWEC expresses concern that, in future years, the Energy Trust may not be able to acquire all cost-effective conservation from large customers due to spending limit imposed by Senate Bill 838.[147]

Sierra Club claims that the Energy Trust underestimated cost-effective energy efficiency potential because: (1) Future savings levels are expected to decline over time; (2) the cost of all achievable EE is overstated; and (3) PGE's avoided cost is likely too low.[148]

Staff encourages PGE to explore opportunities to leverage EE for other demand-side programs beyond IRP analysis. Staff also recommends that PGE adopt the Energy Trust's most recent forecasts into the IRP Action Plan.[149]

PGE's RESPONSE:

5.1.1. *Energy Efficiency Trends*

> ***The Energy Trust appropriately does not speculate about the adoption of currently unknown technologies***

While CUB's observation about the history of EE estimates is accurate, the Energy Trust develops EE potential using a fundamental bottom-up model of existing and emerging technologies. PGE agrees with the Energy Trust's approach and believes this technique better recognizes the limitations associated with EE potential than would a trend or regression analysis. Contrary to suggestions otherwise, Energy Trust does quantify the savings associated with technologies that have been identified but not yet commercialized. Even when including emerging technology in its supply curve, Energy Trust's forecast diminishes over time due to the limited opportunities associated with new measure installs and retrofits. Energy Trust does not speculate as to whether unimagined programs or technologies are realized in outer years.

IRP analysis of the low load scenario can serve as a proxy to gain some insights into the performance of candidate portfolios if actual EE savings far exceed forecast. Future IRPs will develop additional long-term EE forecasts and will provide the opportunity to review how increased efficiency measures outside the action-plan window will affect the long-term demand.

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143 NWEC at 4.
144 *Id.*
145 *Id.*
146 *Id.*
147 *Id.*
148 Sierra Club at 20.
149 Staff at 9-10.

5.1.2. *Standards for Third Party Analysis*

PGE does not own or control Energy Trust data.

PGE only has ownership and control over its own EE data. PGE does not own or control the models or data of any third party on whose studies it relies. This is particularly important in the case of the Energy Trust to ensure that it remains independent from the utility. PGE can work with stakeholders to coordinate with Energy Trust for any required input data or assumptions.

5.1.3. *Large Customer EE Spending Limits*

The large customer EE spending limits have not been met; and, if met, would not materially affect resource need.

PGE understands NWEC's concern that the Energy Trust may not be able to acquire all cost-effective conservation from large customers due to spending limits imposed by Senate Bill 838. While the funding limit may pose challenges in acquiring all cost-effective EE in the future, the limit has not been reached to date. Additionally, PGE notes that the cost-effective EE forecasts provided by ETO to support the 2016 IRP showed that the large customer funding limitation impacted the total forecasted EE savings by less than 0.5%.

5.1.4. *Energy Trust versus NWPCC and Other Forecasts*

Sierra Club's comparison of PGE's and NWPCC's forecast of EE savings is misleading and its characterization of PGE forecasted EE savings relies on misinterpreted figures.

Sierra Club's comparison of PGE's and NWPCC's forecast of EE savings is misleading. Sierra Club points to NWPCC estimates in 2035 to suggest that Energy Trust has underestimated PGE's cost-effective EE potential. Sierra Club states that the Power Council is purported to forecast 4,300 MWa of savings by 2035.[150] On the contrary, the Seventh Power Plan shows that PGE's forecasted load in 2035 is approximately 12% of the regional load forecasted by the Power Council before EE.[151,152] PGE's forecasted incremental EE savings in 2035 is over 9% of the 4,300 MWa forecasted by the NWPCC. That the NWPCC and PGE's EE forecast are roughly equivalent on a proportional basis reinforces the reasonableness of PGE's EE forecast.

Sierra Club's characterization of PGE forecasted EE savings relies on misinterpreted figures. Sierra Club writes that PGE's "future energy savings will substantially decline over time."[153] To support this statement, Sierra Club refers to Sierra Club's Figure 4 which shows "declining

[150] Sierra Club at 22.
[151] Seventh Plan, Appendix E: Demand Forecast Figure E-4.
[152] Response to Sierra Club Data Request No. 010 Attachment B CONF
[153] Sierra Club at 21.

savings projections [that] are not supported by any historical evidence in the region."[154] As Figure 6-2 in the 2016 IRP makes clear, PGE's EE savings substantially *increase* over time. Sierra Club's Figure 4 does not show cumulative savings, but instead annual incremental savings which diminish over time as the opportunity for additional cost-effective measures becomes saturated. When Sierra Club compares its Figure 4 to its Figure 5 in an effort to suggest that PGE's savings fall short of regional history, it asks readers to compare incremental savings from 2010 to 2036 to cumulative historical savings from 1978 to 2015. Despite Sierra Club's assertions, there is no discrepancy in the information provided in PGE's comments.

5.1.5. *EE Cost Effectiveness*

The cost- effective threshold, avoided T&D costs, and conservation adder are appropriate

Sierra Club states that PGE's cost-effective threshold for EE is too low. Sierra Club suggests that the cost-effective threshold should be comparable to the cost of a new CCCT; a comparison only relevant if a CCCT is deemed a reasonable incremental resource.[155] Similarly, Sierra Club suggests that PGE should use a higher NWPCC estimate for avoided T&D costs. NWPCC calculates its avoided T&D costs based on avoided regional transmission and distribution investments. PGE believes it is more appropriate to reflect the cost structure associated with local T&D investments when calculating the cost-effectiveness of EE.

Sierra Club also states that PGE ignores a 10% conservation adder required by the OPUC in calculating avoided costs.[156] As indicated in the email from the Energy Trust (**Attachment G**), the Energy Trust includes a 10% conservation adder in estimating PGE's cost-effective energy efficiency measures.

5.1.6. *Process Timing*

While PGE understands Staff's desire to adopt the Energy Trust's most recent forecast into the IRP Action Plan, PGE notes that the Energy Trust issued an updated short-term forecast in November of 2016, the same month PGE filed its 2016 IRP. PGE incorporated the November 2016 EE forecast into the December 2016 load forecast update. **Section 4.1** of these Reply Comments provides additional information on PGE's updated load forecast.

The development of a new long term EE forecast is more involved and has not yet been undertaken. This process requires coordination between PGE and Energy Trust to ensure appropriate input assumptions. PGE will work with the Energy Trust to generate a new long-term outlook with updated input data, assumptions and programs and plans to incorporate the results in its IRP Update.

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[154] *Id*.
[155] Sierra Club at 24.
[156] Sierra Club at 25.

5.2. Demand Response

PARTIES' COMMENTS:

Multiple parties suggest that PGE's demand response (DR) deployment forecast is overly conservative.[157] At the same time, NWEC recognizes that "[d]eploying DR to scale in PGE's territory and the Northwest will take considerable effort and require a major programmatic effort similar to the scale-up of energy efficiency starting in the 1980s."[158]

OPUC Staff relies on a study that PGE commissioned by The Brattle Group to estimate a summer Direct Load Control (DLC) DR potential of 261-278 MW by 2021, in contrast to PGE's 78 MW forecast.[159] Staff also identifies five distinct DR "sub-resources" applicable to "incremental DR" accounting, and questions PGE's rationale behind including all DR in a single category for modeling purposes.[160] In addition, Staff does not understand the declining DR resource forecast over the 2021-2031 timespan in the high DR future.[161] Finally, Staff questions whether PGE is optimizing the modeling of DR in its portfolio runs.[162]

NWEC advocates for a widespread electric water heater DR program, and claims that "PGE did not include scenarios or other analysis accelerating demand response acquisition opportunities contrary to the Commission's requirements in Order No. 14-415 in PGE's 2013 IRP (pp. 5-6)."[163] CUB criticizes PGE for not projecting the acquisition of "energy storage in the future beyond the 5 MWh required by HB 2193."[164] It also claims that "the Company admits that its DR inputs undervalued the amount of DR the Company had calculated as achievable by 2021 by at least 100 MW" and claims that, "[w]hen pressed, PGE rationalized a 'gradual growth' approach to DR based on factors largely within the Company's control."[165] Similarly, at the February 16, 2017 Commission workshop, Staff questioned the appropriateness of PGE's DR targets based on the Nest Pilot Program's exceedance of early targets.

Staff and ODOE encourage PGE to explore Critical Peak Pricing (CPP) rates in addition to existing Schedule 6 Peak Time Rebates.[166] ODOE also encourages evaluation of DR for renewable integration applications.[167]

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[157] Staff at 10-13; NWEC at 5; CUB at 8-9.
[158] NWEC at 5.
[159] Staff at 10.
[160] *Id.* at 11.
[161] *Id.*
[162] *Id*. at 12.
[163] NWEC at 5.
[164] CUB at 9.
[165] *Id.*
[166] Staff at 12; ODOE at 3.
[167] ODOE at 3.

PGE's RESPONSE:

5.2.1. *Aggressiveness of DR Targets*

The DR targets modeled in the 2016 IRP are based on the identified DR potential with reasonable adjustments to account for practical constraints to implementation.

As discussed in the IRP, PGE contracted with The Brattle Group to develop an updated DR potential study.[168] That study provided PGE with an understanding of the maximum achievable potential DR[169] that PGE could realistically achieve through the deployment of specific DR programs in its service territory under reasonable expectations about future market conditions. .[170] As discussed in Section 6.3.1.4 of PGE's 2016 IRP, the information presented by The Brattle Group was meant to create a starting point from which PGE could apply feasibility constraints. Maximum achievable potential targets cannot be qualified as feasible implementation targets because they do not account for the following constraints:[171]

- Necessity of pilot periods;
- Interaction between programs;
- Participation- and maturation- rates;
- Timing aligned with other initiatives; and
- Evaluation requirements.

PGE develops implementation targets by adjusting maximum achievable potential by the above constraints.

PGE appreciates NWEC's recognition of the effort required to reach maturity in DR deployment, as well as the constructive comments offered by Stakeholders. It should be noted that PGE faces unique circumstances that make achieving current targets difficult. These include:

- **Dual-Peaking System:** As a dual-peaking utility, PGE must acquire demand reduction in both summer and winter. This presents challenges due to the lack of mature industry solutions for winter peaks; and also because the benefits (and therefore allowable costs) of any program must be distributed across two seasons.
- **Lack of Backup Generators:** PGE targets do not include fossil-fuel powered back-up generators. Many programs across the country, against which PGE is benchmarked, include substantial generator load (although exact numbers can be difficult to tease out). While excluding generators maintains a carbon-free program, it

[168] PGE's 2016 IRP at 169.
[169] The maximum achievable potential DR is the achievable reductions for programs in the 75th percentile across the country
[170] PGE's 2016 IRP at 169.
[171] Refer to Section 6.3.1.4 of PGE's 2016 IRP for justification of feasibility constraints.

also impedes the inclusion of customers with high reliability needs such as hospitals and high-tech manufacturers.

- **Immaturity of the Market**: The development of demand response is relatively new in the Northwest market. Lack of awareness can increase the sales cycle and overall customer acquisition costs. While PGE expects this barrier to ease over time, it continues to be an issue, particularly in the business sector.

Among assertions that PGE targets are overly conservative is the claim by Staff that maximum DLC targets can be reached without PGE's Customer Information System (CIS) being operational or fully developed.[172] While it may be technically possible to deploy programs at scale without the CIS, it would lead to additional administrative costs and potential risks to both the programs and the CIS implementation. For this reason, PGE is deploying pilots using third-party systems, but will not have pilots transition to full-scale programs until after the CIS goes live.

PGE reiterates the Company's commitment to aggressively pursue DR in the near term, and notes that the 2021 forecast of 78 MW will approximately triple existing DR resources. PGE currently has two DLC pilots underway: 1) smart thermostat pilot with Nest; and 2) automated demand response (ADR) in partnership with EnerNOC. PGE's Nest pilot is exceeding its targets, while the EnerNOC program (for many of the reasons discussed above) is lagging behind.

In 2017, PGE plans to expand both pilots. The thermostat pilot will soon be expanded to include non-Nest thermostats, and the ADR program will expand to be more inclusive of small and medium business customers. Additionally, PGE is pursuing a mass-market water heater DLC program in the residential sector. Given the administrative and operational challenges involved with bringing pilots to scale as programs, 78 MW of DR represents a significant undertaking for the Company.

CUB claims that PGE, in its Response to OPUC Data Request No. 074, admitted to undervaluing achievable DR by at least 100 MW. As can be seen in PGE's Response to OPUC Data Request No. 074, included as Attachment H, the Company does not state anywhere that it undervalued achievable DR by any amount. PGE also disputes CUB's assertion that PGE controls the limiting factors of DR development. The components of DR expansion within the scope of PGE's influence are customer awareness and winter DR program development. To address these, PGE is completing the Customer Engagement Transformation (CET)[173] and investigating applications and use cases for winter DR.[174] However, these types of market transformations take time. Moreover, there are other limiting factors that PGE cannot change, such as the fact that it is a dual-peaking utility.

[172] PGE's new CIS is set to be deployed at the end of Q1 2018.
[173] *See* ODOE Data Request No. 007.
[174] *See* OPUC Data Request No. 074.

5.2.2. *Types of Demand Response*

> ***While DR targets encompass a range of DR types, the IRP models the full DR fleet as firm and dispatchable. PGE will continue to pursue more sophisticated DR modeling efforts in future IRPs.***

OPUC Staff identified five distinct DR categories that they believe are appropriate for incremental accounting, namely:

- Emergency
- DLC
- Price-responsive
- Back-up generation
- Non-firm.[175]

As in previous IRPs, PGE modeled back-up generation as a resource separate from DR,[176] because it requires fuel-based generators and does not produce reduction in gross load or emissions. PGE agrees with Staff's assessment of back-up generation, but does not consider it an appropriate contributor to DR for IRP purposes.

The remaining four DR types listed by Staff can be consolidated into firm DR and non-firm DR.[177] Staff is correct that PGE applied generic DR inputs to its resource adequacy and dispatch models.[178] This is because PGE's modeling capabilities currently do not allow PGE to model DR with the degree of granularity proposed by Staff. PGE treated the DR fleet input as firm available capacity in the RECAP resource adequacy modeling and as dispatchable capacity with a seasonal energy budget in the AURORA dispatch modeling. Maximum available capacity was adjusted based on anticipated constraints of the programs being modeled.[179] The assumption of a firm resource effectively discounted potential unavailability of emergency DR, assumed fully firm price-responsive programs, and characterized non-firm DR as dispatchable. PGE also did not model programmatic costs for DR.[180] Due to these composite parameters, the availability and cost-savings of DR may be overstated in PGE's results. DR model characterization is early in development and will evolve to include heightened detail in future IRPs.

In terms of program diversity, PGE agrees with Stakeholders that the Company should offer a full suite of demand response options to customers. This is why PGE currently offers firm and non-firm programs. This diversity will lead to greater adoption in the market and a more resilient portfolio. PGE anticipates increasing this diversity as pilots are introduced and/or expanded.

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[175] Staff at 11.
[176] *See* PGE's 2016 IRP, Section 7.1.4, *Distributed Generation*.
[177] *See* Appendix I of PGE's 2016 IRP for delineation of firm and non-firm DR.
[178] As outlined in response to OPUC Data Request No. 059.
[179] *See* PGE's 2016 IRP, Section 6.3.1.4.
[180] *See* PGE's Response to OPUC Data Request No. 059.

Parties posed many questions with regard to pricing, particularly critical peak pricing (CPP). PGE is in the midst of a wide-reaching residential pricing pilot, testing twelve different combinations of time-of-use rates, peak-time rebates, and behavioral demand response. In addition, PGE completed a CPP pilot as part of Schedule 12.[181] PGE plans to deploy a residential rate program in 2019, after the anticipated completion of CET[182] and the current pricing pilot. The Company recognizes significant potential for demand reductions from pricing. However, PGE also recognizes that CPP programs that rely on "Opt-Out" provisions are a form of mandatory time-varying rates, and in the past, customers have demonstrated a reluctance to move towards these types of rates.[183] PGE is considering future inclusion of opt-out programs that have little or no rate impact on the customer, such as peak-time rebates and/or behavioral demand response. Time-of-use rates will be included on an opt-in basis.

5.2.3. ***Change in Anticipated DR Over Time***

> ***The decline in DR resources over the 2021-2031 timespan in the high DR adoption future is driven by the inclusion of opt-out programs.***

Commission Order 14-415 required PGE to develop a range of portfolios that, among other items, include accelerating demand response programs. In compliance with the Commission's directive, PGE modeled accelerating DR resource scenarios, using maximum achievable potential inputs and adding a limited number of opt-out programs.[184] PGE limited the application of opt-out futures in response to stakeholder concerns over mandatory (i.e., opt-out) variable pricing, particularly for residential customers.[185] PGE also included portfolios with accelerated DR compared to the quantities in the 2013 IRP.

In reference to Staff's concerns regarding the resource decline shown in PGE's response to OPUC DR 59, the reason for the initial increase and then gradual decrease in portfolio size is due to the offsetting adoption behaviors of each program type. Opt-in programs increase to a steady-state adoption over time. Opt-out programs, however, start at full adoption and then gradually decrease to a steady-state participation level. The decline in DR resources over the 2021-2031 timespan in the high DR adoption future accounts for a subset of customers choosing to withdraw from opt-out programs.

5.2.4. ***Modeling DR Dispatch in IRP***

> ***AURORA simulates a unique DR dispatch profile for each year.***

PGE disagrees with Staff that "PGE's model of DR dispatch shows utilization of DR only once during each DR season; summer or winter through 2050. The table on Sheet 2 of IR Attach D

[181] See Appendix I.2.1 of PGE's 2016 IRP.
[182] See publicly available documentation of UM 1708.
[183] Order No. 12-159 at 2.
[184] *See* PGE's 2016 IRP Table 6-8.
[185] *See* Order No. 12-159 in Docket No. UM 1415.

shows that PGE is dispatching an undefined DR resource at full capacity in September and again in December."[186] The high-case dispatch model for DR, requested by OPUC in Data Request No. 059, made available an incremental quantity of DR energy that could be divided among the months of July-September and December-February.[187] AURORA allocated the DR energy across the seasons using a linear programming (LP) dispatch routine, the results of which were reported in Attachment D of PGE's response to OPUC Data Request No. 059. AURORA simulates a unique dispatch profile for each year. Though September and December dispatches are very common, these months do not contain all applications of DR through 2050. As shown in Appendix H of PGE's 2016 IRP, on-peak price forecasts regularly reach seasonal maxima in September and December. While December dispatch corresponds with the traditional winter system peak, September dispatch is driven by a confluence of low hydro, declining solar, and lingering high temperatures, which is expected to yield high seasonal prices. The timing of DR dispatch reflected in Attachment D serves to optimize the variable cost savings associated with DR resources.

5.2.5. *Non-Capacity Uses for DR*

> ***Renewable integration use cases will be evaluated in PGE's current and forthcoming pilots, where appropriate.***

Renewable integration is a major driver of DR development.[188] The Company will continue to explore load shaping applications and ancillary services related to expanding penetrations of renewables. These use cases will be evaluated in our current and forthcoming pilots, where appropriate.

5.3. Capacity Products

PGE views comments related to the inclusion of contracts, the modeling of generic resources, and the fact that the Action Plan is agnostic to technology as very interrelated and driven in part by how PGE characterizes capacity products in the IRP. This section includes a discussion of proxy resources, seasonal contracts, and resource duration. **Section 5.4** specifically addresses hydro contract options.

PARTIES' COMMENTS:

Several parties express concern with PGE's reliance on proxy resources in the IRP, specifically with the modeling of Efficient Capacity as a combined cycle combustion turbine and Generic Capacity as a simple cycle frame turbine.[189] NIPCC states that "by using only a single generic capacity resource (regardless of which resource displays the lowest lifecycle fixed and variable

[186] Staff at 12.
[187] *See* PGE's Response to OPUC Data Request No. 059.
[188] See PGE's 2016 IRP, Section 6.3.
[189] NWEC at 2; Sierra Club at 7; Invenergy at 3.

operating costs), PGE has no information regarding the value of different resource attributes to its system."[190]

Several parties also provide comments regarding the duration of resources evaluated in the IRP. Staff states that "PGE's portfolio construction and overall analysis seems to be weighted toward long-term assets."[191] NIPPC states that it "agrees that PGE appears to have a short-term resource need, but submits that PGE has not adequately analyzed short-term opportunities to address that need"[192]and suggests that "PGE could 'rent' capacity from a gas plant with a shorter PPA rather than buy a gas plant."[193] CUB suggests that "PGE should be required to compare medium and long-term resources based on the life or contract length of the medium-term resources" and that "PGE's IRP never considers whether a five-year resource could be a lower cost option during those first five years."[194]

PGE also received comments on these topics at the February 16, 2017 Commission workshop. At the workshop, Commissioner Bloom suggested that it may be preferable to rely on short or medium term products in order to preserve optionality. Chair Hardie asked how the duration of an investment factors into the evaluation of resources. And Commissioner Savage encouraged additional analysis regarding duration.

PGE's RESPONSE:

PGE appreciates the level of engagement on the topics of proxy resources, contract options, and resource duration. Furthermore, PGE agrees with Parties that there may be specific resources or contract options over various durations that could provide additional value to customers not captured by the modeling of proxy capacity resources in the IRP. The recognition of this possibility is a primary driver for the design of a technology-agnostic Action Plan, which delineates the services best suited to meeting PGE's needs rather than dictating which resources should provide those services. PGE acknowledges that many Parties have a desire not only to allow for contracts and shorter duration resources in the Action Plan but also to compare them on an economic basis to the proxy resources within the IRP.

There are several challenges inherent to modeling contracts or shorter duration resources in the context of an IRP. In this section, PGE discusses the challenges in modeling capacity products in the IRP and explains the rationale behind the reliance on proxy resources rather than specific alternative resources or contract options in the 2016 IRP.

190 NIPPC at 7.
191 Staff at 4.
192 NIPPC at 26.
193 *Id.* at 27.
194 CUB at 5-6.

5.3.1. *Proxy Resources*

> ***PGE's reliance on proxy resources in portfolio evaluation is consistent with common industry practice.***

The use of proxy resources in IRP analysis is an accepted and common practice, both inside and outside the Northwest. During the IRP process, utilities use proxy resources to identify potential resource additions, but proxies do not constitute the actual resources the utility would acquire in future procurement actions. IRP processes are typically public processes that occur prior to RFPs and rely on candidate resource characteristics that are often prepared by third-party experts, which can be shared publicly. Details about the availability, cost, and parameters of specific projects are established through an RFP process or bilateral negotiations. These details are confidential and usually subject to non-disclosure agreements. Until a bidder makes a specific resource available, it is highly speculative to assume the terms that the bidder may present.

All major Northwest utilities make use of generic or proxy resources in IRP analysis. For example, Avista stated in its 2015 IRP that "the resources described in this chapter are mostly generic, as actual resources identified through a competitive process may differ in size, cost, and operating characteristics due to siting or engineering requirements".[195] Similarly, PacifiCorp stated in its 2015 IRP that: "Resource information used in the 2015 IRP, such as capital and operating costs, are based upon recent cost and performance data. However, it is important to recognize that the resources identified in the plan are proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resource identified in the plan with respect to resource type, timing, size, cost and location."[196] Furthermore, a review of recent IRPs indicates that IRPs outside of the Northwest also make use of generic resources.[197]

Contrary to NIPPC's statements, PGE did explore the economic tradeoffs between specific resources when designing portfolios. In PGE's response to OPUC Data Request No. 001, PGE showed a comparison of the net heat rates and overnight capital costs of six candidate thermal resources. This data is presented below in **Figure 7**. Of these six technologies, the IRP portfolios specifically incorporate the 1x1 GE 7HA.01 and the 1x0 GE 7F.05. PGE chose these two technologies in order to investigate the tradeoffs between high efficiency and higher capital cost options versus lower efficiency and low capital cost resource options. Reciprocating engines and aeroderivative combustion turbines were not considered in IRP portfolios because they were outperformed by combined cycle resources with respect to both cost and efficiency and because

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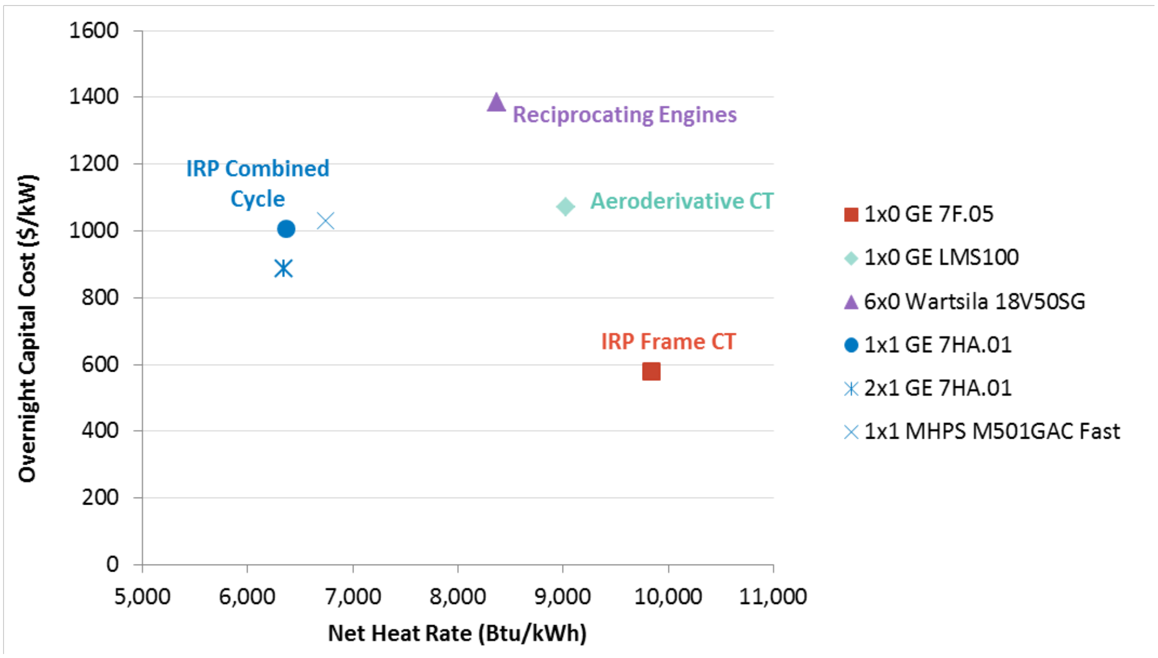
[195] Avista's 2015 Electric Integrated Resource Plan, at 9-1, Aug. 31, 2015.

[196] PacifiCorp's 2015 Integrated Resource Plan, at 213-14, Mar. 31, 2015.

[197] Source: Berkeley Research Group, 2017. *See, e.g., Indiana Municipal Power Agency, 2015 Integrated Resource* Plan at 6-41 ("The purpose of an IRP is to assist the company in determining its future generation requirements at a basic needs level, not to select the specific unit type and model. For example, IMPA does not screen various brands and models of CTs against each other to determine the generic CT for use in the IRP expansion...The selection of the actual brand and model to construct would be determined in the bid and project development process."); *see also, Dominion Virginia Power's and Dominion North Carolina's 2016 Integrated Resource Plan*, Case No. PUE-2016-00049, Docket No. E-100, Sub 147 (filed April 29, 2016) (relying on generic solar, combined cycle, and the like); Los Angeles Department of Water and Power, *2016 Integrated Resource Plan*, January 13, 2017 (Considering "generic types of future generating resources with locations or projects that are not yet identified.".)

PGE did not identify a specific need for flexibility or modularity beyond the capabilities of the combined cycle and frame CT resource options in the REFLEX study. NIPPC commented on this finding and the quality of the REFLEX study at length and PGE responds to those comments in **Section 4.4** of these Reply Comments. Among combined cycle options, while the 2x1 GE 7HA.01 is the best performing with respect to both cost and efficiency, it has a net capacity of 810 MW. Among the smaller combined cycle units, the 1x1 GE 7HA.01 performs best with respect to both efficiency and capital cost.

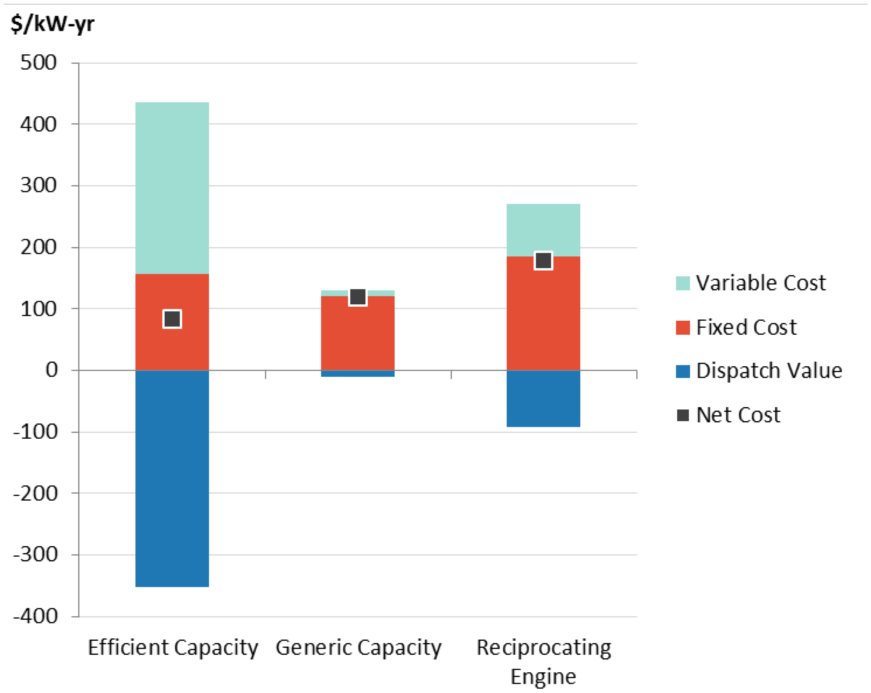
FIGURE 7. Comparison of thermal resource cost parameters



PGE also notes that in addition to these resources, the Company also evaluated two dispatchable non-fossil fuel technologies (geothermal and biomass) within AURORA and put significant effort into quantifying the value of energy storage resources within the PGE portfolio in Chapter 8 of the 2016 IRP. As some Parties note, PGE did not quantitatively evaluate hydro resources in the IRP. This decision was rooted in the wide variability in hydro contract structures and pricing that may be available to the Company. The challenges in modeling contracts are discussed further in **Section 5.3** and hydro contracts are specifically addressed in **Section 5.4** of these Reply Comments.

While PGE did not incorporate reciprocating engines into portfolio analysis, the Company did evaluate the performance of reciprocating engines in AURORA in order to confirm its intuition regarding the competitiveness of the technology. The cost and performance assumptions for this analysis were based on Black & Veatch's report "Characterization of Supply-Side Options," which is included as Appendix K in the 2016 IRP. The resulting fixed and variable costs and dispatch (or market) value are summarized in **Figure 8** on a real-levelized basis for the efficient and generic capacity resources modeled in the IRP and for a reciprocating engine. As anticipated, the reciprocating engine suffers from both higher fixed costs and less competitive dispatch economics than the efficient capacity resource, resulting in a higher net cost than both the efficient and generic capacity resources on a real-levelized basis. This data supports PGE's decision not to include reciprocating engines in portfolio analysis. However, PGE acknowledges that real resource options may have different cost or performance data than that provided by Black & Veatch, and therefore ensured that the Action Plan did not preclude such resources from bidding into a capacity RFP.

FIGURE 8. Real levelized net costs of thermal resource options in 2021



5.3.2. *Resource Duration*

> ***The economic value of shorter-than-life resource durations is highly sensitive to contract pricing and terms, and therefore cannot be evaluated in a generic way within an IRP.***

Consistent with IRP Guideline 1 and past acknowledged IRPs, PGE considered resource options with different lifetimes in order to ensure that different durations were considered in the 2016 IRP. Table 7-4[198] compares the economic assumptions associated with supply-side resources and shows different durations. PGE also incorporated Energy Efficiency (EE) resources with various durations in its 2016 IRP. The common assumption across each of these resources is that the duration corresponds to the economic life of the resource in order to ensure that all costs are accounted for, which results in resource durations that are fundamentally linked to the technology type and financing assumptions.

Beyond this level of analysis, Parties' comments suggest a desire for PGE to evaluate the relative competitiveness of resources with different durations within a given technology class and to

[198] *See* PGE's 2016 IRP at 212.

perform this analysis within the IRP. For example, while the IRP has shown that a 35-year Efficient Capacity resource lowers portfolio costs relative to an equivalent amount of 30-year Generic Capacity, Parties' seem to be interested in whether a five-year contract for capacity of a given type would lower portfolio costs relative to the full life of a project of the same type. This question is challenging because it requires PGE to make unsubstantiated assumptions regarding the cost structures of potential contracts.

Fundamentally, contracts for energy and/or capacity are based on the economics of the physical resources that back those contracts. In other words, an asset owner who seeks to sell the capacity and/or energy associated with the asset will attempt to recover the full fixed costs associated with the asset and earn a return through those contracts. If the owner of the asset successfully secures contracts over the full life of the project, then the average contract price may be estimated based on the annualized capital cost plus the annual fixed and variable costs of the resource in the years over which the contract is valid. This is one approach to approximating the economics of the "renting" strategy proposed by NIPPC.[199] This is also how resources are modeled in the IRP. Importantly, PGE performs the financial modeling of resources in the IRP based on PGE revenue requirement analysis rather than speculating as to the financing structure and target return pursued by potential counterparties. Resource costs in the IRP, therefore, do not account for the possibility that counterparties may pursue a higher rate of return or that contract structures may not spread fixed costs evenly across the life of the asset or evenly across the multiple offtakers that may be required to ensure financial viability of the project.

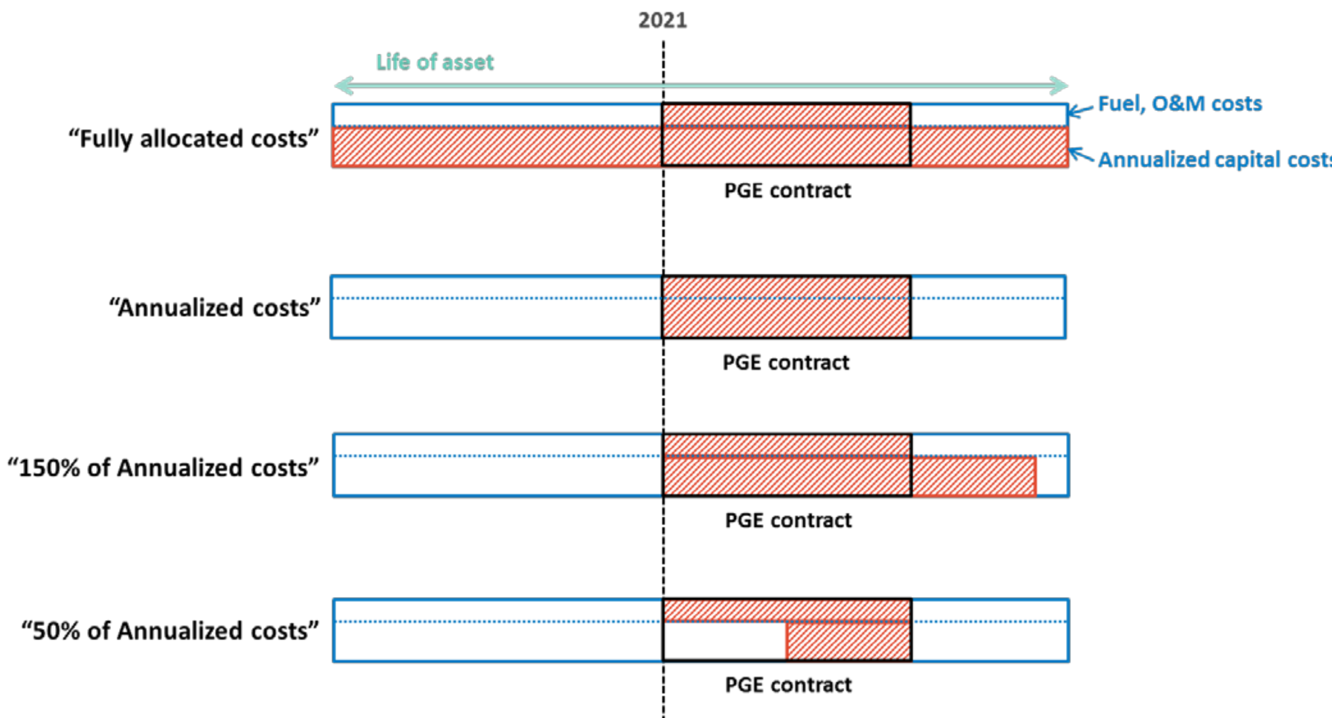
Real contracts are far more complex both in their terms and their pricing structures than the model described above and employed in the IRP. Furthermore, the terms and pricing of contracts will fully determine whether a contract of a given duration is preferable to a contract of a different duration or the procurement of a new resource through ownership or a life of asset contract.

To demonstrate the challenge in quantitatively evaluating different durations in the IRP, PGE presents the following exercise, which considers the economics of various contract options (both duration and structure) that serve the purpose of deferring full life of asset procurement.

For this exercise, PGE considers four hypothetical contract prices, motivated by four different strategies with which a counterparty may attempt to recover the fixed costs associated with an asset. These four strategies are visualized in **Figure 9** and are described below. In **Figure 9**, the blue box represents the total cost of the asset over its full life, the black box represents the duration of PGE's hypothetical contract, and the red shaded area represents the portion of the asset costs embedded in the contract price.

[199] NIPPC at 2.

FIGURE 9. Simplified contract pricing strategies under consideration



The four strategies are:

- "Fully allocated costs." Under this extreme strategy, the counterparty seeks to recover the full capital cost of the resource over the duration of the PGE contract. The contract price therefore reflects the fuel and O&M costs associated with the years of the contract and the annualized capital cost over the full life of the asset. Fundamentally, this represents a scenario in which the counterparty is unable to secure contracts for years prior to or after the PGE contract and is unable to offset a portion of the fixed costs through market sales.
- "Annualized costs." Under this strategy, the counterparty seeks to recover only the annualized capital cost and the fuel and O&M costs over the duration of the PGE contract. This may arise if the counterparty has already paid for a portion of the remaining asset capital costs and/or is willing to take on the risk of paying for some portion of the remaining asset capital costs through other non-PGE contracts.
- "150% of Annualized costs." This strategy is similar to the "Annualized costs" strategy, except it considers the possibility that the counterparty may seek to recover additional fixed costs due to either other contracting arrangements or a desire to reduce risk.
- "50% of Annualized costs." This strategy is similar to the "Annualized costs" strategy, except it considers the possibility that the counterparty may seek to recover fewer fixed costs due to either other contracting arrangements or a higher risk appetite.

Notably, this list excludes an option in which a capacity product is available at market energy prices. Such a construct would be similar to the treatment of Front Office Transactions in PacifiCorp's IRP and in the portfolio analysis conducted by Mr. Mullins' and included in ICNU's comments. Under this construct, PGE is assumed to cover none of the fixed costs associated with the generation behind the capacity product and is exposed to the market for variable costs. This construct assumes that either another party pays for all of the fixed costs associated with the resource or that market prices are high enough for potential counterparties to cover all of their fixed costs by dispatching in the energy market. Across the futures modeled in the IRP, PGE identified no new capacity resource that could cover its fixed costs purely through market revenues.

This is a simplified view of contract pricing strategies,[200] but it provides a useful range of sensitivities over which to investigate resource duration. PGE evaluated the NPVRR impact of a strategy in which the Company procures 5-year and 9-year contracts of these four types in 2021 in order to defer procurement of a life-of-asset resource relative to a strategy of procuring a life-of-asset resource in 2021. The findings are shown in **Table 13** for efficient capacity resources. All NPVRR values are listed per kW of resource procurement.

TABLE 13. NPVRR impact of shorter duration contracts relative to full life of asset procurement, 2016$/kW

Contract Pricing Strategy	5-yr Contract	9-yr Contract
Fully-allocated costs	+$1,132	+$877
Annualized costs	-$58	-$65
150% of annualized costs	+$239	+$430
50% of annualized costs	-$355	-$561

As illustrated in **Table 13**, the competitiveness of contracts for durations that are shorter than the full resource life depends entirely on contract pricing. Under the "Annualized costs" pricing strategy, a 9-year contract is lower cost than a 5-year contract and both contract durations are lower cost than pursuing full life-of-asset procurement in 2021. However, this finding is highly sensitive to the contract price strategy. Under the "150% of annualized costs" pricing strategy, the 9-year contract is the most expensive option and life-of-asset procurement in 2021 is the least expensive option, and by a much larger margin.

The high degree of sensitivity identified in this simplified analysis demonstrates that an evaluation of resource duration critically relies on input assumptions that are highly resource- and counterparty-dependent and cannot be evaluated in a generic manner in an IRP. Despite this tension between the principles of IRP modeling and the speculative nature of devising generic shorter-than-life resources, PGE recognizes that existing resources and contract options may provide a cost effective means for meeting the needs of PGE customers and has therefore crafted

[200] For example, the analysis neglects the possibility that older existing assets may have higher fixed O&M costs associated with maintenance than newer existing or new assets.

an Action Plan that allows PGE to continue to pursue contracts through short- and mid-term activities and that allows counterparties to offer shorter than full asset life duration contract options in subsequent RFPs. However, the Company firmly contends that it would be inappropriate to attempt a quantitative evaluation of generic resources with durations that are shorter than the full asset life based on highly speculative assumptions within the context of an IRP.

In addition to these technical challenges in making meaningful quantitative statements regarding resource duration in the IRP, PGE also contends that the pursuit of such an exercise would be counter to the foundational requirements of long-term planning unless fully accounting for all fixed costs. Fundamentally, if PGE were to assume in its long-term planning that other parties would pay for a portion of the fixed costs associated with resources meeting PGE's customer needs, the Company would be adopting a "free rider" strategy. PGE believes that this is an irresponsible strategy from the perspective of regional resource adequacy. If all utilities in the Northwest were to adopt a similar strategy, then new resources to replace retiring coal, replace old and higher emitting natural gas plants, maintain resource adequacy, and integrate renewables may not be viable.

A free rider strategy may appear compelling when considering only short-term factors, but the natural progression of such a strategy may introduce new costs and risks to customers. OPUC Staff alluded to the risk of relying on short- and mid-term products to meet capacity needs in a long-term planning exercise in PGE's 2009 IRP Acknowledgement order: "Staff agrees with NIPPC and NWEC that power purchases from independent power producers or the wholesale power market could be used to bridge the early energy and capacity deficits associated with these scenarios. Staff concludes, however, that the risk associated with the deliverability and cost of such power is not in the best interest of ratepayers"[201]

Furthermore, recent history provides an example of these risks being realized. After a period of successful reliance on shorter-term market purchases in the 1990s, PGE's customers were hit by unprecedented market turmoil, summarized in our 2002 IRP[202] as follows:

- Rolling blackouts in California in the winter of 2000-01;
- Record high prices for all tenor of purchased power, from hour-ahead to future multiple-year term deals in the winter and spring of 2001;
- Federally imposed Western Electricity Coordinating Council (WECC)-wide price caps in June 2001.

The Commission acknowledged the need for long-term commitments to secure sustained, affordable, and reliable energy, and supported PGE's prudent resumption of its long-term procurement, as proposed in the 2002 IRP. As a result, PGE added more than 1,000 MW to its portfolio, in the form of both contracted and owned capacity.

[201] Order No. 10-457 at 14.
[202] *See* PGE's 2002 Integrate Resource Plan, Final Action Plan, at 1, March 2004.

5.3.3. ***Seasonal Contracts***

PGE explored seasonal contract economics in IRP Section 5.1.4.1.

In designing portfolios in the 2016 IRP, PGE considered several of the factors brought up by Parties. For example, in early iterations of portfolios (see Roundtable #16-1 on March 9, 2016), PGE proposed to specifically fill a portion of capacity needs in each year with seasonal capacity products (i.e., contracts) and to fill remaining needs with annual products (i.e., contracts or physical resources). PGE did not take this approach in the final IRP analysis because of two critical constraints:

1. The lack of a commonly accepted approach to allocating capacity needs to annual versus seasonal products; and
2. Unavailability of cost assumptions with which to compare annual to seasonal products on an economic basis. This challenge is similar to the pricing challenges described in Reply Comments **Section 5.3.2**, but with the added complexity that resources behind seasonal products may have multiple offtakers throughout a given year.

PGE instead performed the stand-alone analysis described in Section 5.1.4.1 of the 2016 IRP. This analysis found that "a blend of annual and seasonal products has the potential to achieve a reduced costs compared to annual products alone. Despite this insight, the optimal combination of seasonal and annual resources cannot be determined prior to evaluating actual bid information."[203] In light of this analysis, PGE determined that because seasonal and annual capacity product prices are speculative, the Company could not propose a specific allocation of the capacity need to winter or summer capacity products in the IRP that would provide the best balance of cost and risk to customers. In recognition of this complexity, PGE seeks to meet capacity needs with an RFP that is open to annual and seasonal capacity resources and to rely on LOLE modeling to ensure that the portfolio of acquired products meets annual reliability standards.

Ultimately, PGE chose to represent capacity products in the 2016 IRP as annual products in which PGE pays the annualized capital cost over the full life of the asset. The Company determined that all identified alternatives would fundamentally rely on highly speculative input assumptions about contract options that are resource- and counterparty-specific. In particular, the Company believes that it would be irresponsible to incorporate resource actions in the Action Plan under the assumption that other parties would pay some of the costs associated with those resources. If, for example, the Action Plan explicitly required the pursuit of contracts or existing resources under such an assumption, then PGE would risk being locked into the procurement of resources that may be higher cost than their corresponding representation in the IRP and higher cost than other alternatives in an RFP.

[203] PGE's 2016 IRP at 124.

5.4. Hydro Contracts

PARTIES' COMMENTS:

Several parties suggest that PGE should assume expiring contracts are renegotiated and included in portfolio analysis.[204] In addition to expiring hydro contracts, NWEC suggests that PGE should evaluate potential new hydro resources within the IRP.[205] ICNU also suggests that PGE should wait to "develop and issue a capacity RFP at least until after [PGE] knows whether the Wells contract will be extended."[206]

Staff compared the portfolio percentages of hydro resources in Figure 2-1 from the 2013 IRP and Figure 1-2 from the 2016 IRP and noted a "drop off" in hydro with seemingly little or no information as to the results or activities around renewing existing hydro contracts or the availability of new hydro contracts.[207]

PGE's Response:

5.4.1. *Hydro Contract Renewal Assumptions*

> ***For IRP planning purposes, PGE does not speculate as to whether or on what terms hydro contracts might be renewed.***

PGE does not assume that expiring hydro contracts will be renewed for IRP planning purposes. Each hydro contract is unique with project specific characteristics and terms. The original contracts have often been executed decades earlier under substantially different market conditions and may not contain renewal rights. As such, generic assumptions about renewal terms or quantities would be highly speculative. Additionally, PGE's experience negotiating renewals of its hydro contracts, and negotiating commercial energy agreements generally, has demonstrated that it is unrealistic to expect that any negotiation will result in an agreement that reflects initial expectations or negotiating positions. Indeed, in order to preserve the opportunity to capture the best deal possible, it is prudent and in the best interest of customers to enter discussions with a certain amount of flexibility to allow for productive negotiations. It is also important to have the flexibility to walk away from negotiations if the parties cannot reach acceptable terms. "Locking in" a specific amount of capacity that PGE expects to obtain and the expected timing for negotiating the transaction unnecessarily ties PGE's hands in negotiations, thereby potentially precluding it from capturing the best deal for its customers.
See **Section 2.5** and **Attachment A** for a discussion of the Wells contract.

[204] Staff at 22; NWEC at 2.
[205] NWEC at 2.
[206] ICNU at 24.
[207] Staff at 25.

5.4.2. *Hydro Resource Modeling in the IRP*

PGE does not evaluate specific hydro contract options in the IRP because quantities and terms are unknowable.

As discussed above, PGE is unable to speculate within the context of an IRP as to the quantities and terms of hydro contract renewals that may be available. This is also true for potential new hydro contracts. Contracts with hydro counterparties can take a variety of forms. In the simplest case, parties may offer a fixed share of a hydro resource, in which case the resource could be modeled as a physical hydro resource, sized in accordance with the contract quantity. Contract price would still be difficult to predict under such an arrangement, but resource behavior may be approximated in the context of an IRP. However, in most cases, the involved parties negotiate more complicated terms and pricing in order to account for other obligations or to lower cost or mitigate risk to their constituents. Contracts may therefore involve varying resource availability by season; differentiation between capacity obligations and energy obligations; pricing that incorporates different combinations of fixed and variable cost terms; and a wide range of other terms or instruments that may impact the resource adequacy contribution, dispatch behavior, and cost of the contracted resource. Importantly, the resulting characteristics of the contract may be partially or wholly decoupled from the physical capabilities of the resource and/or the true costs of owning and operating the resource. The highly contract-specific terms cannot be approximated in a generic manner or tied to engineering estimates.

Furthermore, if PGE were to devise generic hydro contracts for inclusion in portfolio analysis, then the performance of the hydro contract portfolios would be driven by the underlying contract assumptions, which would be highly speculative. If hydro contract portfolios were considered actionable within an IRP, then such an exercise may risk the introduction of a narrow and specific resource action into the Action Plan that cannot be effectuated because there would be no guarantee that such a contract option exists.

For all of these reasons, PGE does not explicitly model new hydro contracts in the IRP. However, given the potential value to customers of hydro contracts, PGE ensured that the Action Plan would not preclude the pursuit of such contract options and, as discussed in **Section 2.5**, PGE is actively exploring opportunities to acquire existing hydro capacity.

5.4.3. *Hydro Resources 2014-2017*

The IRP explains the drop off in hydro between 2014 and 2017.

Regarding Staff's concerns about the apparent drop off in hydro when comparing the portfolio percentages of hydro resources in Figure 2-1 from PGE's 2013 IRP and Figure 1-2 from the 2016 IRP, PGE notes that in the 2013 IRP figure, the section labeled Hydro 20 includes contract hydro and most of PGE-owned hydro. Approximately 2% of additional PGE-owned hydro is included in the Renewables section. As stated in the 2013 IRP, contract hydro included a four-year contract that expired at the end of 2015 with no renewal rights.[208] In the 2016 IRP, Figure 1-

[208] *See* PGE's 2013 IRP at29, NextEra.

2 is described on page 41 and the description notes that the Contracts portion includes contracted hydro, wind, and solar resources The section labeled PGE Hydro includes only PGE-owned resources. The total of the owned and contracted hydro resource is 20% of the portfolio resource mix.

5.5. Distributed Energy Resources (DER)

PARTIES' COMMENTS:

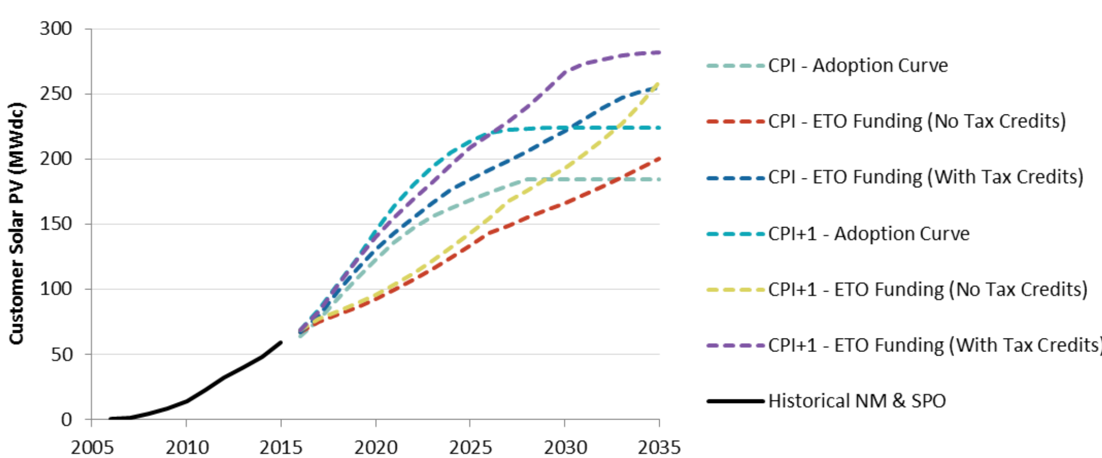
Staff states that they are "supportive of many of PGE's efforts to incorporate DERs in the IRP to date,"[209] but notes some areas for improvement. Staff recommends that "PGE continue to refine their assessments of individual DER growth and make explicit use of any study results within their IRP modeling."[210] CUB also notes that PGE's approach does not directly incorporate distributed generation and specifically rooftop solar PV into its load forecast model.[211]

PGE's Response:

PGE's treatment of DER is reasonable

As described in **Section 4.1.9**, PGE does not explicitly model behind-the-meter PV systems within the load forecast, but implicitly captures these systems through accounting for historical changes to load. Given that installations of behind-the-meter PV on the PGE system remain relatively modest and that Black & Veatch identified potential for customer adoption of rooftop PV systems that is largely consistent with historical adoption rates, the Company believes that this is a reasonable approach at this time. **Figure 10** shows the adoption rates modeled by Black & Veatch next to the historical customer PV adoption.

FIGURE 10. CUSTOMER SOLAR PV ADOPTION (HISTORICAL AND BLACK & VEATCH FORECAST)



209 Staff at 38.
210 Staff at 38.
211 CUB at 9-10.

In the 2016 IRP, PGE also tested multiple portfolios with incremental solar resources to evaluate the economic competitiveness of solar versus wind resources for meeting RPS obligations. This analysis indicated that solar resources, with cost and performance data corresponding to utility-scale systems, were not lower cost on an NPVRR basis than wind resources. Rooftop solar is both more costly and tends to have lower capacity factors than utility-scale solar resources. Despite the potential benefits associated with being located on the distribution system, rooftop PV systems tend to have higher net cost impacts to the system than equivalently sized utility-scale solar PV systems because of these two key drivers. The relative cost of solar versus wind identified in the IRP, therefore, represents a lower bound on the relative cost of rooftop PV versus wind. Due to this inherent lower bound, PGE did not include portfolios with explicit treatment of rooftop PV systems that exceed the adoption rates implicitly embedded within the load forecast.

PGE appreciates Staff's interest in continuing to improve the treatment of DERs in IRP modeling tools and looks forward to discussing methodologies toward this end in future IRP public processes.

6. Modeling

6.1. Portfolio Construction

PGE considers portfolio construction to be a foundational aspect of IRP analysis. In designing portfolios, PGE sought to answer specific questions regarding the economics of various resource options, to be responsive to the 2013 IRP Acknowledgement Order (Order 14-415), and to allow for the identification of a Preferred Portfolio. PGE's approach to portfolio construction is broadly consistent with the approach used in past acknowledged IRPs. The Company also presented and sought feedback on the portfolio construction process, candidate portfolios, and draft portfolio performance at the following PGE-held public meetings:

- Public Meeting 3 (August 13, 2015)
- Roundtable 16-1 (March 9, 2016)
- Roundtable 16-2 (May 16, 2016)
- Roundtable 16-3 (August 17, 2016)

Parties expressed a range of comments regarding portfolio construction and in some cases constructed and analyzed alternative portfolios in their comments. PGE addresses these comments below.

PARTIES' COMMENTS:

Sierra Club noted that PGE did not rely on an optimization model to construct portfolios.[212] Some parties suggested that the variation in resource options across the Actionable Portfolios

[212] Sierra Club at 4.

was too limited,[213] while NWEC characterizes the top performing portfolios as having "dramatically different future resource selections."[214] OPUC Staff suggested that PGE incorporate contract extensions into portfolios[215] and to consider portfolios designed to high and low load growth futures.[216]

ICNU presented analysis that sought to identify a lower cost portfolio than PGE's Preferred Portfolio and to refute the findings in the IRP that early RPS action is lower cost than delayed RPS action and that efficient capacity resources were lower cost than generic capacity resources. These portfolios included: an assumption of renewal of the Wells contract with the same terms and price as the contract that expires in 2018; an assumption of 300 MW of winter on-peak market access, compared to the 200 MW of market access included in the IRP; and Front Office Transactions that vary across portfolios and years to meet remaining capacity shortages, similar to a proxy capacity resource, identified using an inappropriate PRM-based capacity load resource balance analysis.

PGE's RESPONSE:

PGE appreciates the opportunity to provide additional clarity regarding portfolio construction. This topic was discussed with stakeholders at Public Meeting #3 on August 13, 2015, Roundtable #16-1 on March 9, 2016, and Roundtable #16-2 on May 16, 2016. The IRP also includes descriptions of how and why specific portfolios were designed in Sections 10.4 and 10.5 and Appendix O of the 2016 IRP. PGE acknowledges that there is a degree of discretion inherent in the construction of portfolios and that additional clarification regarding portfolio construction may be helpful in interpreting the results of the 2016 IRP.

6.1.1. *Principles in Portfolio Construction*

> ***PGE's portfolio construction methodology ensures that resource options are compared on a consistent basis.***

PGE constructs portfolios in the IRP in order to provide insights regarding the value of various resource options for meeting the long-term needs of customers at the best balance of cost and risk. In the 2016 IRP, the set of Actionable Portfolios were designed to answer two key questions: the relative economics of various RPS technologies, including wind, solar PV, biomass, and geothermal; and the relative economics of more efficient but higher capital cost resources (e.g., a combined cycle combustion turbine), less efficient but lower capital cost resources (e.g., a simple cycle combustion turbine), and wind resources.[217]

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[213] Staff at 31.
[214] NWEC at 16.
[215] Staff at 22.
[216] *Id.* at 32.
[217] In response to Parties' comments, PGE has also prepared a portfolio scoring sensitivity which incorporates the RPS timing portfolios into the set of Actionable Portfolios evaluated. This is discussed in Section 6.4.6 of these Reply Comments.

In designing portfolios, PGE was careful to ensure that portfolio construction controlled for the specific questions under consideration in the IRP. Accordingly, all Actionable Portfolios were required to:

- Meet a loss-of-load expectation of 2.4 hours per year in each year through 2050;[218]
- Achieve RPS compliance through REC retirements in each year through 2050 and achieve physical RPS compliance by 2040;[219]
- Maintain a REC bank balance above the minimum REC bank constraint in each year through 2040.

Meeting all of these requirements ensured that cost differences between portfolios measured the true cost impact of the proposed resource options and did not reflect different reliability or RPS planning standards across portfolios. While Staff has requested that PGE evaluate portfolios designed for different load forecasts, it is important to note that such an exercise would draw false conclusions by comparing portfolios on the basis of cost that meet fundamentally different levels of need. Such an approach would represent a significant departure from past IRP exercises and PGE believes additional deliberation would be required before such an approach could appropriately be applied within an IRP. In these Reply Comments, PGE provides an example of such an approach for a single question: the economics of early RPS action. This example contemplates a zero load growth sensitivity and is discussed in **Section 3.4** of these Reply Comments.

For portfolios that were designed to answer specific questions, the Company was careful to isolate the relevant economic factors. For example, when comparing efficient capacity resources to generic capacity resources, PGE modeled two portfolios identical in everything but the fixed portion of the capacity need that was under investigation. In one portfolio, *Efficient Capacity 2021*, PGE modeled an efficient capacity resource. In another, *RPS Wind 2018*, PGE modeled generic capacity for the same MW size. Doing so avoided conflating the capacity resource economic factors with those related to other portfolio resource decisions.

6.1.2. ***Variation among Actionable Portfolios***

> ***The actionable portfolios investigate a wide range of procurement options and identify a wide range of potential future costs.***

Contrary to the position of Staff, the Actionable Portfolios considered in the 2016 IRP represent a wide range of procurement options in the 2021 time frame. **Figure 11** illustrates both the composition of incremental resources and the Reference Case NPVRR relative to the Preferred Portfolio of these portfolios to illustrate this variability. Figure 11 also includes the RPS Timing portfolios, which have been included in a supplemental scoring analysis at the request of OPUC Staff in **Section 6.4.6** of these Reply Comments.

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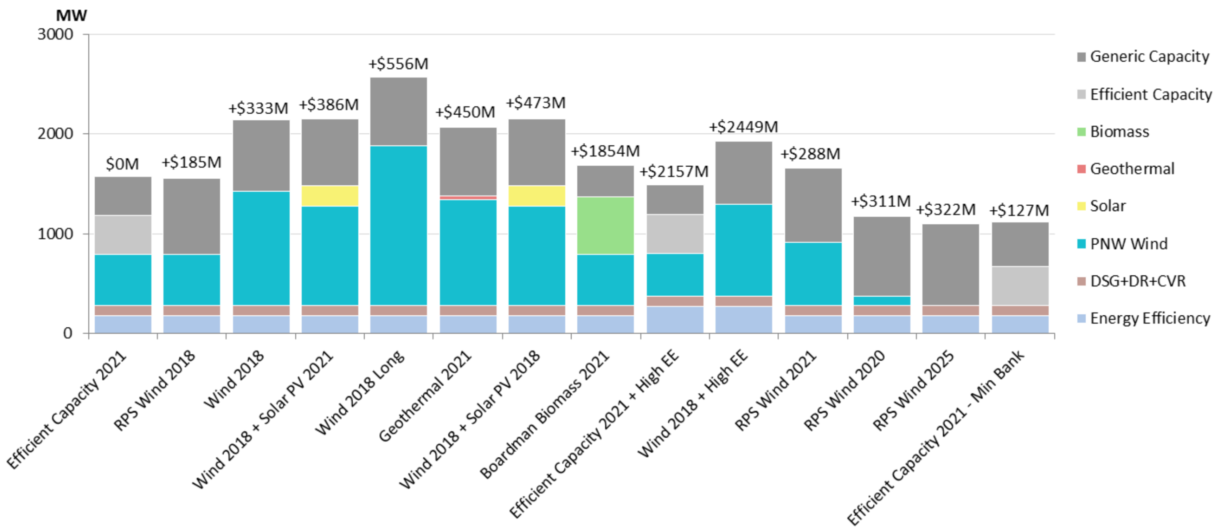
[218] Excluding *Portfolio 1*, which includes no resource actions other than for RPS compliance.
[219] Physical RPS compliance is not a requirement in every year. This allows PGE to minimize the cost of RPS compliance over time through management of the REC bank.

FIGURE 11. Incremental resource additions through 2021 and NPVRR results relative to the preferred portfolio for Actionable and RPS Timing Portfolios



Across these portfolios, the total capacity (renewable and non-renewable) contemplated ranges from approximately 1,100 MW to approximately 2,600 MW due to the varying impact of the renewable capacity factors and ELCCs across portfolios. Renewable additions comprise 0% to 64% of the incremental capacity considered across the portfolios and the portfolios test four distinct renewable technologies. From an evaluation perspective, the Reference Case NPVRR across these portfolios varies by approximately $2.4 billion. PGE also notes that the poorly performing portfolios among this list provide insights regarding the relative economics of various resource options that may not be visible if PGE were to rely solely on optimization modeling to construct portfolios. PGE contends that the portfolio construction process, used in this and prior acknowledged IRPs, allows PGE to investigate a wide range of resource strategies and to identify and address the most critical questions in a given IRP cycle.

6.1.3. *ICNU Portfolio Analysis*

The portfolio analysis used to justify ICNU's assertions lacks the necessary rigor to make meaningful resource comparisons.

ICNU relies on supplemental portfolio analysis by Mr. Mullins to provide an alternative picture of resource economics to the 2016 IRP. The analysis that ICNU relied on in its comments to gain economic insights regarding capacity and RPS resource options does not follow the principles outlined above, and therefore leads to several incorrect or misleading assertions. The analysis is described below.

- The finding that Mr. Mullins' Portfolio 1 was $1.0 billion less expensive than the IRP Preferred Portfolio is not evidence that Mr. Mullins' proposed portfolio represents a lower cost approach to meeting customers' demands than the IRP Preferred Portfolio.

Portfolio 1 in Mr. Mullins' analysis has an associated loss of load expectation of 18.2 hours/year in 2021,[220] while the Preferred Portfolio has a loss of load expectation of 2.4 hours/year in 2021. As described in the 2016 IRP, achieving resource adequacy to maintain reliability comes at a cost. For example, the comparison of the *RPS Wind 2018* and *RPS Wind 2018 + No Capacity Action* portfolios on page 311 of the 2016 IRP identified that the cost of procuring incremental generic capacity resources to maintain reliability was on the order of $2.5 billion on a net present value basis over 2017-2050. As described above, a comparison on the basis of cost between two portfolios that meet different reliability targets provides no meaningful information regarding the relative economics of the resources because the cost differences include both resource-specific cost factors and the cost associated with meeting one resource adequacy target versus another.

- Mr. Mullins also claims that "if physical capacity is truly required in 2021, it would be more cost effective to ratepayers to acquire a smaller, Simple Cycle Combustion Turbine ('SCCT'), rather than a larger, CCCT." This statement is incorrect because the analysis performed to support this statement did not isolate the relative economics of simple cycle versus combined cycle technologies. The simple cycle portfolio (ICNU Portfolio 5) relied on Front Office Transactions to fill the remaining capacity need not identified in the combined cycle portfolio (Portfolio 1). For example, Portfolio 5 includes the simple cycle combustion turbine and 148 MW of Front Office Transactions in 2021, while Portfolio 1 includes a combined cycle resource and no Front Office Transactions in 2021. The cost difference between the two portfolios reflects both the cost difference between combined cycle and simple cycle resources as well as the cost difference between a combined cycle and Front Office Transactions. PGE could not identify in ICNU's Response to PGE Data Request No. 001 any costs attributed to Front Office Transactions in Mr. Mullins' AURORA modeling. If ICNU assumes that Front Office Transactions provide firm capacity to the system at zero cost, then this inappropriate assumption overwhelms the cost savings identified in the IRP associated with meeting capacity needs with efficient capacity relative to generic capacity.

- In addition, Mr. Mullins asserts that if 150 MW of load were to migrate to direct access, then PGE could defer physical resource procurement to 2025 and save ratepayers $433.5 million. This statement is incorrect in part because the portfolio designed to contemplate this option (Portfolio 6) achieves an LOLE of 17.3 hours/year[221] and appears to assume that Front Office Transactions can provide over 200 MW of firm capacity in 2021 at zero cost. As with the comparison between Portfolio 1 and the IRP Preferred Portfolio, Mr. Mr. Mullins conflates the cost of resource adequacy with the economics of resource options.

[220] To determine this LOLE, PGE incorporated Mr. Mullins' assumptions of an extension of the existing Wells contract and the addition of a CCCT with 400 MW January dependable capacity to the base portfolio modeled in the 2016 IRP and ran this portfolio in RECAP.

[221] To determine this LOLE, PGE reduced the load by 150 MW (assuming the system-wide load factor in 2021) and incorporated Mr. Mullins' assumptions of an extension of the existing Wells contract and the addition of 228 MW of firm capacity from Front Office Transactions and ran this portfolio in RECAP.

- Unrelated to portfolio construction, but worth noting, is that Mr. Mullins' claim regarding cost reductions associated with direct access is misleading. SB 1149 directs the Commission to balance the development of a competitive market while avoiding undue cost shifts to cost of service customers. The Commission's historical decisions, including the current cap on direct access, should be interpreted as balancing these competing objectives. Direct access in Oregon has the following characteristics:

  1. The utility maintains the provider of last resort obligation (POLR) as a matter of law.
  2. The Commission has approved 'permanent' opt-out programs that have limited transition adjustment obligations.
  3. The Commission has directed utilities not to plan, for either reliability or energy, for those customers electing to permanently opt out from the utility.
  4. There is no organized capacity market in the region. Customers being served by Energy Service Suppliers (ESSs) are accessing wholesale <u>energy</u> markets to serve their <u>energy</u> needs.

  PGE notes that, not only does this arrangement result in some cost shifts to PGE's remaining customers, but also the Company believes it may result in higher reliability risk for PGE's remaining customers. The combination of PGE's POLR obligations and an inability to plan for the capacity needs of 'permanent' direct access customers means that PGE is effectively capacity-short if such customers return to PGE. PGE's intention is to study such effects from a LOLP perspective in the next IRP. In light of this, there should be no crediting of direct access customers with capacity as neither the customers (nor their ESS) are providers of capacity.

Mr. Mullins' analysis provides several examples of the challenges inherent to portfolio construction and designing meaningful portfolios to answer important planning questions. In particular, ensuring that all portfolios meet the reliability standard without introducing proxy capacity resources is especially challenging. Mr. Mullins relied on Front Office Transactions as proxy capacity resources, allowing them to vary year-to-year and across portfolios. Without meaningful costs for providing this varying amount of capacity, this assumption corrupts the economic comparisons between portfolios and leads to false conclusions in its comments. Similarly, potentially including contracts into portfolio development without meaningful costs or without careful portfolio construction to ensure appropriate (i.e., apples-to-apples) comparisons introduces the risk of drawing false conclusions regarding various resource options.

6.2. Scenario-Based Risk Analysis

<u>PARTIES' COMMENTS:</u>

Parties' concerns with PGE's risk analysis revolved around the lack of a stochastic analysis; the analysis of natural gas futures and risks associated with the acquisition of long-term fossil fuel based facilities.

Sierra Club and ICNU argue that because PGE did not conduct a stochastic analysis to assess risk, it could not adequately assess the risk profile of different portfolios.[222] Similarly, NWEC argues that PGE's approach of treating all futures as equally likely may give too much weight to unlikely futures.[223] NWEC suggests that PGE should use a probability analysis, which assigns each variable a probability of actually occurring.[224]

NIPPC claims the IRP avoids any examination of the different exposure to future fuel prices between flexible capacity resources.[225] While ICNU faults the Company for not modeling a scenario to evaluate the impact that natural gas prices will continue to remain low in the future.[226] NWEC points out that natural gas prices are historically highly unpredictable and suggests that the idea of addressing natural gas price risk through the use of forward curves may be outdated and insufficient. NWEC does not suggest an alternative method.[227] Sierra Club questions the robustness of the Preferred Portfolio to different market conditions, stating that "even a small error in PGE's assumptions regarding the likely cost of market energy in WECC… may have caused its preferred portfolio to appear more favorable than other plans."[228]

CUB points to PGE' Trojan, Boardman, and Carty plants as examples of stranded asset, early retirement, cost overrun and mechanical failure risks associated with the acquisition of long-term fossil fuel based facilities.[229] CUB also raised the issue of Carty's depreciation schedule of 45 years in the Special Public Meeting before the OPUC on February 16, 2017.

PGE's RESPONSE:

Consistent with IRP Guideline 1.b., PGE evaluated economic risk in the 2016 IRP by conducting a scenario analysis that considered portfolio performance across 23 potential futures. Some of these futures test alternative fundamental forecasts (e.g., natural gas price futures), while others test potentially significant structural changes to Western electricity markets (e.g., the high carbon price future). PGE also uses this scenario analysis framework to test critical planning considerations (e.g., the low hydro future). In contrast to a probabilistic or stochastic analysis, PGE does not assign probabilities to these highly uncertain futures.[230] Instead, scenario analysis is used to identify how robust the analytical findings in the IRP are to key uncertainties. In the 2009 IRP Docket, Sierra Club and other parties introduced comments from Schlissel Technical Consulting, TR Rose Associates, and Synapse Energy Economics that agreed that scenario analysis was better suited to resource planning than stochastic analysis.[231] PGE maintains that scenario analysis continues to be an appropriate framework for evaluating risk, particularly when key uncertainties may be driven by structural shifts rather than probabilistic processes, when the

[222] Sierra Club at 11; ICNU, Comments of B. Mullins at 12.
[223] NWEC at 13.
[224] *Id.*
[225] NIPPC at 15.
[226] ICNU, Comments of B. Mullins at 12.
[227] NWEC at 14.
[228] Sierra Club at 8.
[229] CUB at 3.
[230] PGE incorporates stochastic methods into the evaluation of load and system reliability. This is described in Section 5.1.3 of the 2016 IRP and Section 4.1.5 in these Reply Comments.
[231] *See Sierra Club, Columbia Riverkeeper, Friends of the Columbia Gorge, and the Northwest Environmental Defense Center's Exhibit 1*OPUC LC 48, PGE's 2009 Integrated Resource Plan, at 25.

probabilities of key uncertainties are difficult to quantify, and when conclusions regarding risk may be sensitive to assigned probabilities.

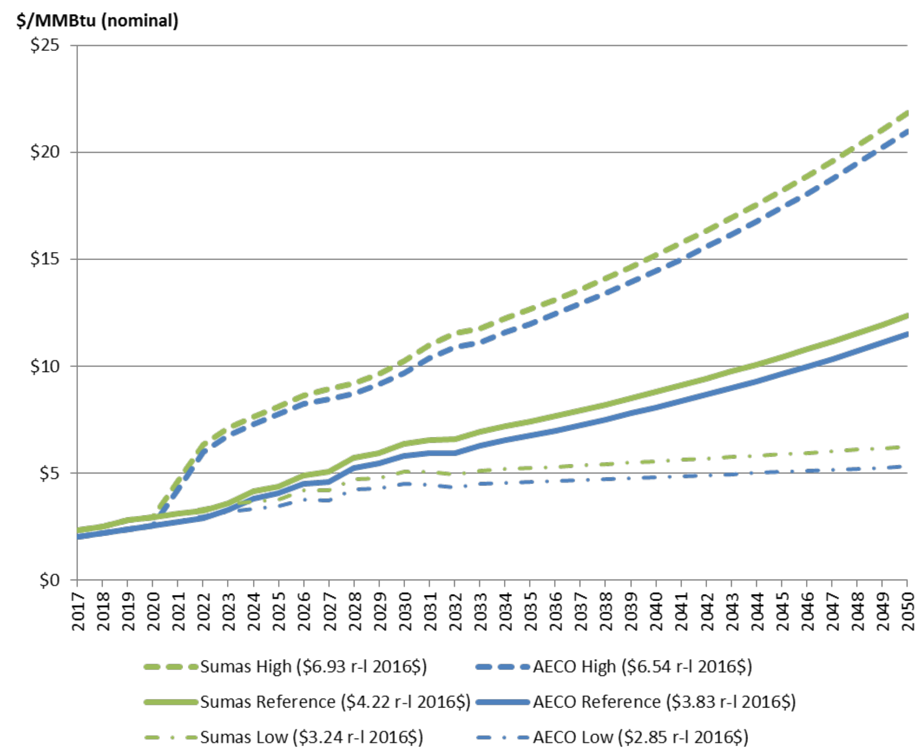
The scenario analysis described in the 2016 IRP identified that the Preferred Portfolio was least cost relative to all other Actionable Portfolios in every evaluated future. This finding indicates that even if probabilities were assigned to the 23 futures, the Preferred Portfolio would still outperform all other portfolios on an expected basis. In these Reply Comments, PGE also shows that the performance of the Preferred Portfolio is robust across additional futures related to low natural gas prices and potential future policy uncertainties. Contrary to statements made by parties, the economics of the Preferred Portfolio are well suited to an uncertain future.

6.2.1. *Low Natural Gas Price Futures*

> ***The findings in the IRP and recommendations within the Action Plan are robust across all modeled futures, including additional low gas price futures.***

In response to inquiries from stakeholders and OPUC Data Request No. 002, PGE evaluated an additional nine futures that contemplated low natural gas prices. PGE's study of additional futures with lower natural gas prices affirms the 2016 IRP's Action Plan. **Figure 12** illustrates PGE's low natural gas price futures relative to reference and high natural gas price assumptions.

FIGURE 12. Reference, high, and low case forecasts for Sumas and AECO hub prices



When the performance of PGE's ten actionable portfolios are simulated under a low gas price future, the portfolio costs are diminished relative to reference case conditions. **Table 14** identifies NPVRR portfolio costs for all actionable portfolios under Wood Mackenzie's H2 2015 low gas price forecast, PGE's reference CO2 price forecast, and PGE's reference load forecast. **Table 15** identifies how PGE's portfolio scoring would change if nine additional low natural gas futures (coupled with unique CO_2 and load conditions) were included in PGE's application of portfolio scoring metrics. As can be observed through comparison of **Table 14** with Table 12-12 of the 2016 IRP and **Table 15** with Table 12-16 of the 2016 IRP, lower natural gas prices do not alter the ranking of portfolio costs or portfolio score. This finding reinforces the durability of PGE's portfolio results and the reasonableness of PGE's Action Plan.

TABLE 14. Portfolio costs under low natural gas prices

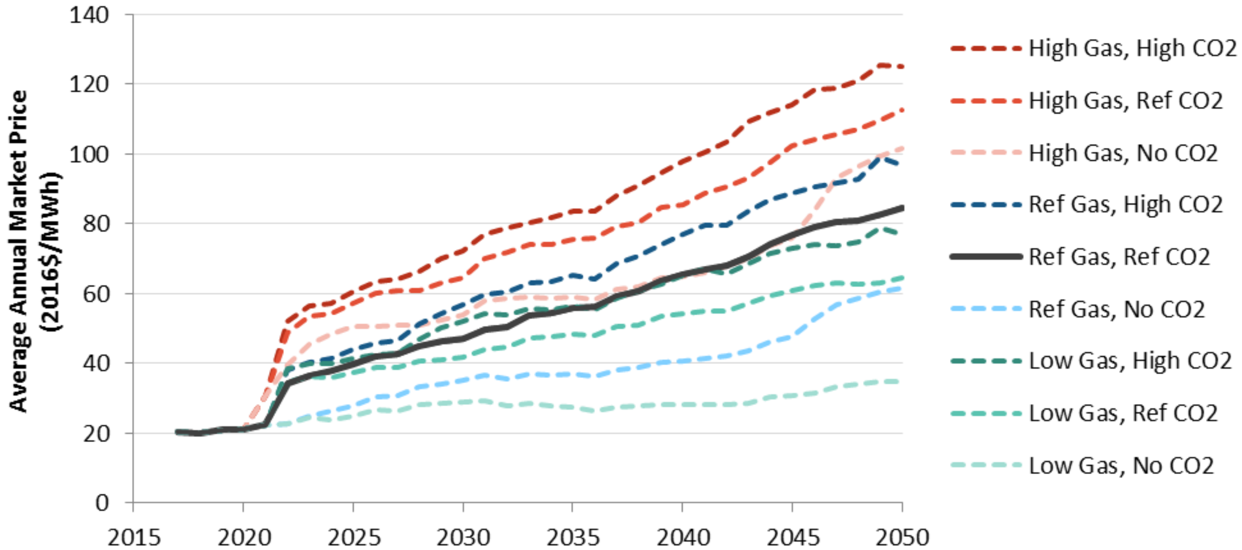
Portfolio Name	2017-2050 NPVRR 2016$ millions
Efficient Capacity 2021	29,739
RPS Wind 2018	29,972
Wind 2018	30,082
Wind 2018 + Solar PV 2021	30,130
Geothermal 2021	30,199
Wind 2018 + Solar PV 2018	30,217
Wind 2018 Long	30,376
Boardman Biomass 2021	31,630
Efficient Capacity 2021 + High EE	31,995
Wind 2018 + High EE	32,305

TABLE 15. Portfolio scoring summary including low gas price futures

Rank	Portfolio Name	Cost	Severity	Variability	Future Durability	Total Weighted
1	Efficient Capacity 2021	100	100	0	100	83
2	Wind 2018 Long	77	94	100	60	81
3	RPS Wind 2018	92	93	5	100	79
4	Wind 2018	86	89	23	90	77
5	Wind 2018 + Solar PV 2021	84	85	14	50	67
6	Geothermal 2021	82	83	23	50	67
7	Wind 2018 + Solar PV 2018	81	81	14	50	64
8	Boardman Biomass 2021	24	21	53	0	24
9	Efficient Capacity 2021 + High EE	12	10	71	0	19
10	Wind 2018 + High EE	0	0	88	0	15

Contrary to parties' comments, PGE evaluated a wide range of potential market conditions in the 2016 IRP. Across the 32 modeled futures (including the low natural gas price futures described above), PGE evaluated portfolio performance in nine distinct wholesale energy market price futures, which are summarized on an annual basis through 2050 in **Figure 13**.

FIGURE 13. Average annual market prices across futures



As shown in Appendix L of the 2016 IRP and in the discussion of the low gas price futures above, the three primary findings of the 2016 IRP are robust across futures. Specifically:

1. The *RPS Wind 2018* portfolio, which includes a 100% PTC eligible RPS resource, is lower cost than all other RPS timing portfolios across all futures;
2. Portfolios with Efficient Capacity (high capital cost, low heat rate) resources displacing a portion of Generic Capacity additions in 2021 are lower cost than portfolios that meet all remaining capacity needs (after EE, DR, and renewables) with Generic Capacity (low capital cost, high heat rate); and
3. The *Efficient Capacity 2021* portfolio (the Preferred Portfolio) is the lowest cost portfolio among the set of Actionable Portfolios across all futures.

The results of PGE's scenario analysis show conclusively that small deviations from Reference Case assumptions would not result in a different Preferred Portfolio and would not change the economic conclusions regarding early RPS action or Efficient versus Generic Capacity. As described above, even the relatively large deviations from the Reference Case explored within the 2016 IRP do not impact the conclusions made in the 2016 IRP or the recommendations in the Action Plan.

6.2.2. ***Stranded Asset Risk***

> ***PGE evaluated the risk associated with Efficient Capacity resource procurement across a wide range of carbon price futures and considered additional policy-driven risks.***

Parties suggest that the actions in PGE's recommended Action Plan will not be cost effective in an uncertain future. However, they provide no evidence to support their claim. In contrast, PGE has offered robust analysis demonstrating that the actions identified in the Action Plan are the least-cost outcomes in all futures studied.

Parties do not identify under what future conditions the economics of the recommended Action Plan would be compromised. The futures studied in the 2016 IRP include an expansive range of policy futures including $200 / ton CO_2 prices (nominal). PGE assumes that parties are wary of long-term investments in thermal technology that may prove uneconomic due to very low market prices, or due to emission caps that would prevent regular dispatch of a new thermal resource. PGE shares these concerns and therefore, explicitly models futures in the 2016 IRP with low market prices and futures with stringent CO_2 targeted policy.

The futures evaluated in the 2016 IRP demonstrate that new thermal resources can operate cost effectively amidst the electric power industry's transition to lower carbon intensities. Under reference case conditions including $39/ton (2016$ real-levelized) CO_2 prices, CO_2 emissions WECC-wide track climate based emission goals through 2035. Under the high CO_2 future including $60/ton (2016$ real-levelized) CO_2 prices, CO_2 emissions WECC-wide track climate based emission goals through 2040.[232] The studies demonstrate that PGE's evaluation of new resources does not under-forecast the potential impact of CO_2-based policy; the 2016 IRP forecasts the electric power sector reducing emissions over the next two decades on a trajectory to reduce WECC-wide emissions by 80% below 2005 levels by 2050.[233] As such, PGE remains confident that the risks related to wholesale power changes driven by policy to reduce CO_2 emissions have been captured in the 2016 IRP.

Despite the robust fundamental analysis presented in the 2016 IRP demonstrating the durable economics of the recommended Action Plan, parties, including CUB, suggest that long-term fossil-fuel based facilities may be forced to retire early, become stranded assets, or otherwise not operate as forecasted.[234] However, parties have not explained why new fossil-fuel based facilities would be prevented from operating as forecasted. CUB suggests that changes to technology, including demand response, energy efficiency, and energy storage will provide PGE with more cost-effective capacity in "10, 20 let alone 30 years."[235] However, PGE cannot wait 30 years to meet its capacity needs. PGE has demonstrated a significant capacity deficit in the 2021 timeframe that must be filled in order to maintain reliable operations.

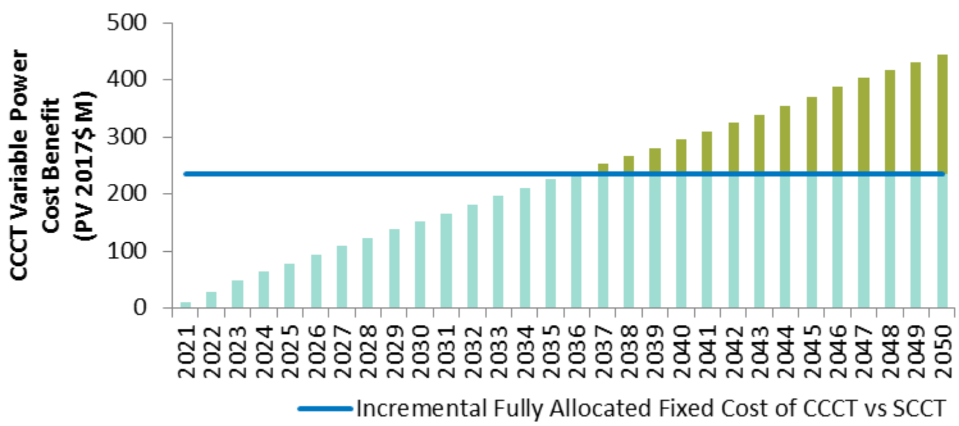
To further support its reply comments, PGE has explicitly studied the risk that a combined-cycle combustion turbine (CCCT) would not be able to operate as forecasted. PGE has evaluated the

[232] PGE's 2016 IRP at 75.
[233] *Id.*
[234] CUB at 3, line 10.
[235] CUB at 8, line 9.

relative economics between the *Efficient Capacity 2021* and the *RPS Wind 2018* portfolio and studied the portfolio's relative economics were the efficient CCCT capacity resource to be no longer able to operate economically as forecast.

Pursuing an Efficient Capacity strategy remains least cost even if the facility is forced to cease economic operation well ahead of its asset life. PGE's analysis shows that relative to alternative, cost-effective capacity resources studied in the IRP, an Efficient Capacity resource strategy remains lowest cost even if a CCCT is only able to operate economically for fifteen of its thirty-five year life. Every year a CCCT is in operation, it reduces PGE's variable portfolio costs by diminishing more expensive market purchases. After 15 years, under reference case conditions, the present value of the cumulative savings exceed the present value increase in fixed costs necessary to construct and keep a CCCT online for its thirty-five year life relative to the fixed costs of a Generic Capacity resource (modeled as a SCCT). As illustrated in Figure 14, every year the facility is able to operate economically after its fifteenth year generates substantial savings for PGE's customers relative to a lower fixed cost, higher variable cost Generic Capacity strategy.

FIGURE 14: CCCT variable power cost cumulative benefit relative to SCCT



It appears that parties' concerns regarding stranded assets are, in part, grounded in a misunderstanding of how resource economics are affected by resource life. CUB suggests that PGE's analysis 'favors the long-term resource' and provides 'Attachment A' that is intended to demonstrate 'why PGE's analysis of long and medium term resource costs is problematic.'[236] However, as CUB's Attachment A reveals, CUB has mischaracterized how resource life affects resource economics.

CUB's referenced Attachment A misconstrues how asset life affects project economics. CUB provides the following example:

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[236] CUB at 5, line 15.

> For example, the costs of the hypothetical gas plant modeled in CUB's Attachment A, is $33-44/MWH in the first of the plant's 30-45 year useful life. As PGE's assets depreciate with time, the resource begins to become more economical. In the case of the hypothetical gas plant, customers pay $32-41/MWH in the plant's fifth year and $30-38/MWH in the plant's tenth year. CUB does not dispute that levelized cost analysis is appropriate for an asset that serves customers for many years. However, that economic argument only works if the plant actually serves at that level, without additional costs for the specified period of time, and the risks associated with our analysis (discussed below) tend to decrease over time.[237]

There is much that is unclear in CUB's example. Importantly, it is unclear whether CUB is referring to a hypothetical plant's dispatch cost, its fully allocated levelized cost of energy, or something new. CUB's Attachment A does not tie with the plant costs detailed in the example, nor is there enough detail provided in the estimate to clarify whether CUB is accurately reflecting hypothetical plant costs. While unclear, CUB's language seems to mistakenly suggest that the IRP's modeled resource value increases as hypothetical facilities are depreciated. This is incorrect.

PGE's IRP framework applies real-levelized fixed costs to all years in which the resource is present in the portfolio. Variable costs associated with plant dispatch—and the associated reduction of more expensive power purchases (i.e., the plant's market value)—is simulated in each year of PGE's portfolio analysis. A resource's dispatch cost and market value are based exclusively on the facility's variable cost and market prices. The fixed costs associated with the project and the resource duration has no impact on the resource's dispatch cost. The analytical framework employed by PGE treats resources of different resource life appropriately.

PGE also disagrees with CUB's characterization of previous resource decisions as the basis for forward stranded asset risk. Boardman was initially put into service in 1980, and will cease coal-fired operation at the end of 2020. The initial estimated life of the plant was 40 years. PGE's 2007 IRP reiterated the assumption, noting "Boardman will be fully depreciated in 2020."[238] The 2007 IRP also noted that additional investments in emissions controls would enable continued operations at the plant. Such investments could increase the service life to 2040. PGE's 2009 IRP initially determined Boardman operating through 2040 with capital upgrades, including pollution controls would be the least cost, least risk approach. After working with stakeholders, a Boardman 2020 plan was proposed which included a commitment to cease coal operations at the end of 2020. The timing of Boardman's planned end of coal-fired operations is consistent with initially forecasted estimates of the plant's useful life.

Contrary to CUB's statements, PGE is not proposing a new thermal resource with a 45-year life. The 2017 IRP has evaluated an Efficient Capacity resource with a 35 year life. CUB's reference to Carty's assumed resource life conflates criteria for investment decisions with subsequent depreciation assumptions designed to lower rate impacts. PGE's site certification for Carty uses an estimated useful life of 30 years, consistent with past practice as well as RFP analysis. PGE's

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[237] CUB at 6, lines 5-13.
[238] PGE's 2007 IRP at 45

filed depreciation study shows an average service life of 35 years. For rate purposes, however, a service life for Carty is set at 45 years, which is the result of a Stipulation between PGE, OPUC Staff, and CUB.[239]

6.3. Planning Horizon and End Effects

PARTIES' COMMENTS:

ICNU questions PGE's decision to model costs through 2050, rather than evaluating the NPVRR over a 20-year horizon. ICNU claims that "the effect of this is to overemphasize the projected savings associated with the Company's proposed near-term acquisition of an RPS resource."[240]

In addition, at the February 16, 2017 Commission workshop, both Chair Hardie and Commissioner Savage inquired about a 34-year versus 20-year planning horizon and Commissioner Savage requested additional information about how end effects are treated in the IRP.[241]

PGE's RESPONSE:

In the 2016 IRP, PGE evaluated revenue requirement impacts over the period from 2017 to 2050 and incorporated the NPVRR over this 34 year time frame into portfolio scoring. This approach is consistent with IRP Guideline 1c, which requires the planning horizon for analyzing resource choices to be at least 20 years and account for end effects. The IRP Guidelines direct utilities to consider "all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource."[242] PGE explicitly models costs based on forecasts that extend beyond a 20-year planning horizon in order to quantify these end effects. If PGE's IRP analysis were to only include a resource's revenue requirement for the first twenty years of the resource's life, the analysis would not capture the resource's revenue requirements in years 21 through the end of its economic life or the facilities net salvage cost. Further, a twenty year analysis would only capture the resource's wholesale market value for a portion of the facility's life.

In addition, PGE sought to evaluate portfolios that both comply with SB 1547 through the 2040 time frame (year 24 in the planning horizon) and to identify opportunities to reduce RPS compliance costs to customers by leveraging the timing flexibility enabled by Oregon's RPS REC bank provisions. This required portfolio development with varying renewable additions made through 2040 in order to explicitly capture the costs and benefits of these additions.

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[239] Docket No. UM 1679, Staff-CUB-PGE/100 at 5 – 6.
[240] ICNU at 9.
[241] Commissioner Savage also had questions concerning the terminal value methodologies used in an RFP analysis. As discussed in other sections of these Reply Comments, issues pertaining to RFP design and scoring should be addressed in the RFP docket.
[242] IRP Guideline 1c.

PGE also sought to inform ongoing dialogue around Oregon's greenhouse gas (GHG) goals by modeling the system through 2050. While SB 1547 makes significant progress toward Oregon's 2050 goal by 2040, PGE included modeling through 2050 to help quantify the remaining challenge that Oregon will face in the 2040s to meets its long-term GHG goals.

In response to parties' comments, this section includes additional planning horizon sensitivities and additional discussion of end effects in the IRP.

6.3.1. *Planning Horizon Sensitivities*

The conclusions in the IRP are robust across additional planning horizon sensitivities.

In response to comments from parties and the Commission, the Company conducted two additional sensitivities regarding the planning horizon and end effects. In the first sensitivity, the NPVRR is calculated over a truncated 20-year horizon. In the second sensitivity, the revenue requirement is explicitly modeled through 2050, as in the IRP, and the revenue requirement in all years after 2050 is approximated as the 2050 revenue requirement, escalated for inflation. In this sensitivity, NPVRR is calculated over an infinite horizon, similar to a terminal value calculation. The resulting NPVRRs for the Actionable Portfolios, plus the RPS timing portfolios, are summarized in **Table 16** under the Reference Case assumptions and can be found in Attachment I for all futures (including the low gas futures). **Table 16** also lists the difference in NPVRR, under each sensitivity, between each portfolio and the Preferred Portfolio, *Efficient Capacity 2021*, listed under the "Δ" column.

TABLE 16. NPVRR sensitivities, Reference Case

2016$, millions	34-year NPVRR (2016 IRP)		20-year NPVRR (truncated)		Infinite horizon NPVRR (constant real costs, 2050+)	
Portfolio	**NPVRR**	**Δ**	**NPVRR**	**Δ**	**NPVRR**	**Δ**
Efficient Capacity 2021	31,319	0	20,347	0	48,306	0
RPS Wind 2018	31,504	+185	20,415	+68	48,699	+392
Wind 2018 Long	31,875	+556	20,772	+425	49,114	+807
Wind 2018	31,652	+333	20,572	+225	48,870	+564
Wind 2018 + Solar PV 2021	31,705	+386	20,624	+277	48,922	+616
Geothermal 2021	31,769	+450	20,661	+313	49,024	+717
Wind 2018 + Solar PV 2018	31,792	+473	20,710	+362	49,011	+704
Boardman Biomass 2021	33,173	+1,854	21,713	+1,365	50,849	+2,543
Efficient Capacity 2021 + High EE	33,476	+2,157	22,722	+2,374	49,938	+1,632
Wind 2018 + High EE	33,768	+2,449	22,904	+2,556	50,456	+2,149
RPS Wind 2020	31,630	+311	20,555	+208	48,805	+499

RPS Wind 2021	31,607	+288	20,525	+178	48,792	+485
RPS Wind 2025	31,641	+322	20,568	+221	48,813	+506
Efficient Capacity 2021 - Min Bank	31,446	+127	20,491	+144	48,411	+105

Table 16 and **Attachment I** the Preferred Portfolio, *Efficient Capacity 2021*, is lowest cost on an NPVRR basis relative to all other Actionable and RPS timing portfolios in all futures for each of the sensitivities. In addition, when comparing the RPS timing portfolios, the *RPS Wind 2018* portfolio, which pursues early RPS action to secure 100% PTC eligibility, is lower cost than the alternative delay portfolios across all futures in all sensitivities. These sensitivities are also incorporated into the discussion of Portfolio Scoring in **Section 6.4.6** and the 20-year NPVRR sensitivities are incorporated into the discussion of the RPS Analysis in **Section 3.4** of these Reply Comments.

6.3.2. *End Effects in the IRP*

End-effects are appropriately captured in the IRP for the modeled generic resources.

PGE's IRP appropriately includes end effects through the use of real-levelized fixed costs, and an extended planning horizon to identify long-term variable cost and wholesale market value. To capture end effects, PGE's IRP framework identifies the present value of a facility's fixed costs for the entire project life. Beginning with the total present value of fixed costs, PGE then uses annuity methods to identify the real-levelized fixed cost. The real-levelized fixed cost reflects an annual cost attributable to each year of the resource's life. PGE's IRP framework applies a resource's real-levelized fixed costs for all years that a resource is included in the portfolio to appropriately capture resource costs across the entire project life, including repowering costs should the planning horizon extend beyond the underlying resource's economic life.

PGE's IRP framework captures a resource's variable costs and wholesale market value by extending the planning horizon to adequately capture nearly all years of the generic resource's economic life. For example, PGE's generic Efficient Capacity resource has an economic life of 35 years. The resource is introduced into the portfolio in 2021. The generic resource's economic life continues until 2055. By modeling the resource's present value variable cost and wholesale market value through 2050, PGE appropriately captures the majority of the resource's value and suitably models the resource end effects.

6.4. Portfolio Scoring

The 2016 IRP scoring methodology is based largely on precedent established in prior acknowledged IRPs. In particular, PGE looked to the discussion of scoring metrics that took place in the 2009 IRP[243] to ensure general consistency with past acknowledged IRPs. For the 2016 IRP, parties express several concerns with both specific scoring metrics and how PGE

[243] Order No. 10-457, at 25-27.

combined those metrics to result in an overall portfolio score. PGE discusses the rationale behind individual scoring metrics and addresses Parties' comments through a supplemental sensitivity analysis. The sensitivity analysis demonstrates that the conclusions made in the IRP are robust to the scoring recommendations made by parties and across a wide range of weights applied to cost and risk.

PARTIES' COMMENTS:

Parties provide several comments regarding the construction of specific scoring metrics, the weighting of scoring metrics, and the inclusion of specific portfolios in portfolio scoring. These are discussed below.

Regarding the cost metric, Staff expresses a preference for using average costs rather than Reference Case costs to represent the cost metric.[244] Staff suggests that the severity metric be calculated for each portfolio for compliance with IRP Guidelines, but not included in portfolio scoring.[245] Regarding the variability metric, Staff suggests that the semi-variance "under weighs the possibility that a particular portfolio may result in lower than expected costs".[246] Sierra Club similarly states that "the Company should have employed a standard measure of variance that took both high- and low-cost results into account".[247] Staff also states that the durability metric "suffers from the same problem as the overall scoring system… in which the set of portfolios included when constructing the durability score may actually affect the rankings."[248] Staff further recommends that the Company consider "discarding the durability measure".[249] Sierra Club and NWEC also recommend that PGE remove the durability metric from scoring[250] and RNW expresses concern with the equal weighting of the durability, variability, and severity metrics.[251]

Staff is also concerned with aspects of the portfolio scoring that resulted in portfolio scores that varied depending on the portfolios included in the scoring exercise. This includes the durability metric, as described above, and the scaling of portfolio metric scores to fall between 0 and 100 across the scored portfolios. Staff also recommended that PGE include Portfolio 17-21 in portfolio scoring.

[244] Staff at 29.
[245] *Id.* at 29-30.
[246] *Id.*
[247] Sierra Club at 15.
[248] Staff at 30.
[249] *Id.* at 31.
[250] Sierra Club at 16; NWEC at 14.
[251] RNW at 17.

PGE's RESPONSE:

6.4.1. *Cost Metric*

> ***The cost metric applied in the 2016 IRP remains a reasonable estimate of expected portfolio costs.***

Consistent with prior acknowledged IRPs, PGE represents the cost metric as the NPVRR of the portfolio under Reference Case assumptions. PGE believes that the Reference Case remains a reasonable estimate of expected costs. In response to suggestions from stakeholders that the cost metric could alternatively be calculated as an average NPVRR across futures, PGE provided a supplemental cost/risk analysis in Appendix L of the 2016 IRP to identify whether using an average cost versus the Reference Case cost had significant implications for the cost/risk trade-off. The Company did not identify a significant difference in relative portfolio performance on the basis of cost and risk between cost metric definitions in this supplemental analysis.

PGE notes that calculating a meaningful average cost across the futures requires both the assignment of probabilities to each future and the design of futures to approximate the full distribution of possible outcomes with regard to key variables. Such a probabilistic approach has fundamentally different objectives than the scenario analysis approach employed by PGE, which seeks to identify risks associated with specific futures and to identify portfolios that are robust across a range of plausible and/or critical outcomes. In contrast, probabilistic analysis seeks to predict outcomes with some level of certainty based on forecasted distributions of key inputs, an exercise that puts higher emphasis on speculative inputs, like the distributions of future natural gas prices.

6.4.2. *Variability Metric*

> ***Consistent with prior acknowledged IRPs, the variability metric addresses the asymmetry in the impacts of higher than expected and lower than expected costs to customers.***

PGE used a semi-variance to quantify variability in past acknowledged IRPs and in the 2016 IRP, in part, because the impacts of higher than expected electricity costs to customers are not evenly offset by the benefits of lower than expected electricity costs. PGE contends that it is important to continue to carefully consider the implications of this asymmetry and looks forward to discussing this metric with stakeholders in future IRP public processes.

6.4.3. *Severity Metric*

> ***The severity metric is consistent with prior acknowledged IRPs and the specific recommendations of Parties in the 2009 IRP.***

PGE included the severity metric in response to OPUC Guideline 1c, which requires that "the plan include, at a minimum: 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes."[252] In designing the scoring metrics for the 2016 IRP, PGE considered the concerns raised by stakeholders as summarized in the Acknowledgement Order for the 2009 IRP.[253] One common concern among stakeholders was that the severity metric should not subtract the Reference Case cost from the average cost across the four highest cost futures for each portfolio. In particular, NWEC stated that "any metrics such as these that subtracts out the mean, in cases where the mean can be very different across tested portfolios, is faulty, since high variability in itself is not a bad outcome."[254] Staff also warned against using a severity metric that "may assign a lower risk to a portfolio that has both a higher expected (or reference case) cost and a higher extreme (or worst case) cost."[255] Given this context, PGE notes that sentiments regarding the severity metric and the relative importance of high cost versus low cost outcomes in portfolio evaluation have taken a stark turn since the acknowledgement of the 2009 IRP. Given past commentary on the severity metric, PGE believes that a robust discussion on the relative importance of high cost versus low cost outcomes should be undertaken before the severity metric is considered for removal from scoring.

6.4.4. *Durability Metric*

> ***The durability metric provides insight regarding relative portfolio performance that is important in scenario analysis and not captured by other risk metrics.***

The durability metric was designed to capture the preference for portfolios that consistently perform strongly relative to alternatives and to penalize portfolios that consistently perform poorly relative to alternatives. PGE described this metric in the 2009 IRP Addendum (Section 10A.10). In Order No. 10-457, the Commission acknowledged the 2009 IRP and did not question the durability metric. The Commission determined that "PGE's risk analysis is robust and satisfies the requirements of IRP Guidelines 1b, 1c, 4i, 4j and 8a."[256] PGE maintains that comparing the relative performance of portfolios within specific futures is an especially useful exercise in scenario analysis, and hence incorporated the durability metric into scoring in the 2016 IRP.

In the most simplistic case under a scenario analysis framework, PGE contends that a portfolio that outperforms all other portfolios, regardless of which future is realized, should be preferred to the other portfolios. Similarly, a portfolio that has the worst performance among portfolios in all futures should be excluded. However, scenario analysis is not always as straightforward as these two examples. PGE acknowledges that the construction of the durability metric relies to some extent on arbitrary definitions of strong and poor relative performance and that the metric is unitless, and therefore not comparable on a consistent basis with other cost and risk calculations, which have the unit of dollars. Despite these challenges, PGE finds the durability metric to be

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[252] Order No. 07-047, Appendix A at2.
[253] Order No. 10-457, at 25-27.
[254] *Id.* at 26.
[255] *Id.*
[256] Order No. 10-457 at 27

helpful and includes it in the 2016 IRP. PGE looks forward to discussing the use of a durability metric in future IRP cycles.

6.4.5. *Invariant Scoring*

PGE agrees that invariant scoring is worthy of discussion in future IRP public processes, but it does not impact the Preferred Portfolio in the 2016 IRP.

PGE agrees with Staff that some aspects of the scoring methodology lead to scores that vary depending on the portfolios included in scoring. In particular, as Staff mentions, the durability metric, which explicitly scores portfolios on the basis of their performance relative to others, introduces this challenge. The methodology by which PGE scales cost and risk scores so that the portfolio scores fall between 0 and 100 also leads to portfolio scores that depend on the portfolios included in portfolio analysis. This methodological approach was developed in order to better resolve differences between portfolios that may be small relative to the magnitude of the metric.

As shown in the following supplemental scoring analysis, the effect of the scaling methodology does not have an impact on the Preferred Portfolio in the 2016 IRP, but does impact the relative performance of portfolios, particularly the *Wind 2018 Long* portfolio, which has a low variability score and a high cost score. PGE considers this an important area of continued discussion and looks forward to engaging stakeholders in discussions of improved methodologies in future public IRP processes.

6.4.6. *Supplemental Scoring Sensitivity*

The findings in the 2016 IRP are robust to sensitivities around scoring methodology, weighting, and the NPVRR calculation.

In response to Staff and stakeholder comments described above, PGE includes an additional supplemental scoring sensitivity that includes the modifications relative to the scoring in the 2016 IRP. PGE presents this analysis for informational purposes and does not propose adoption of this approach in this IRP. The goal of the analysis is to test the sensitivity of PGE's findings to the factors discussed by Parties in their comments. The sensitivity analysis makes the following modifications to the 2016 IRP scoring methodology:

1. The severity and durability metrics are removed from the portfolio score;
2. The variability metric is calculated as the standard deviation across futures to incorporate consideration of lower than expected cost outcomes;
3. Cost and Risk are compared on a consistent basis with a common unit of dollars;
4. Portfolios 17-20 are included in the scoring exercise to provide insight regarding the cost and risk balance of the portfolios that incorporate delayed RPS procurement. Portfolio 21 is excluded because it does not include the costs of the assumed unbundled REC purchases; and

5. The supplemental low gas future modeling results developed in response to OPUC Staff Data Request No. 002 are included in the calculation of the Variability risk metric.

Table 17 provides the cost and variability metrics associated with this scoring sensitivity.

TABLE 17. Cost and variability scores in scoring sensitivity

Portfolio	Cost (2016$, millions)	Variability (2016$, millions)
Efficient Capacity 2021	31,319	3,393
Efficient Capacity 2021 - Min Bank	31,446	3,359
RPS Wind 2018	31,504	3,410
RPS Wind 2021	31,607	3,384
RPS Wind 2020	31,630	3,379
RPS Wind 2025	31,641	3,376
Wind 2018	31,652	3,410
Wind 2018 + Solar PV 2021	31,705	3,419
Wind 2018 Long	31,875	3,271
Geothermal 2021	31,769	3,411
Wind 2018 + Solar PV 2018	31,792	3,418
Boardman Biomass 2021	33,173	3,357
Efficient Capacity 2021 + High EE	33,476	3,247
Wind 2018 + High EE	33,768	3,265

In response to parties' concerns regarding the sensitivity of the portfolio score to the weights applied to cost and risk metrics, PGE provides portfolio score sensitivities using three weighting schemes in **Table 18**: 50% Cost, 50% Risk; 75% Cost, 25% Risk; and 25% Cost, 75% Risk. Note that in this sensitivity, low portfolio scores are preferable to high portfolio scores in portfolio ranking.

TABLE 18. Portfolio scores in scoring sensitivity

Portfolio	50% Cost, 50% Risk Score	Rank	75% Cost, 25% Risk Score	Rank	25% Cost, 75% Risk Score	Rank
Efficient Capacity 2021	17,356	1	24,338	1	10,375	1
Efficient Capacity 2021 - Min Bank	17,403	2	24,424	2	10,381	2
RPS Wind 2018	17,457	3	24,481	3	10,434	4
RPS Wind 2021	17,496	4	24,551	4	10,440	5
RPS Wind 2020	17,504	5	24,567	5	10,442	6
RPS Wind 2025	17,508	6	24,574	6	10,442	7
Wind 2018	17,531	7	24,591	7	10,470	8
Wind 2018 + Solar PV 2021	17,562	8	24,634	8	10,490	9
Wind 2018 Long	17,573	9	24,724	11	10,422	3
Geothermal 2021	17,590	10	24,680	9	10,501	10
Wind 2018 + Solar PV 2018	17,605	11	24,699	10	10,512	11
Boardman Biomass 2021	18,265	12	25,719	12	10,811	13
Efficient Capacity 2021 + High EE	18,362	13	25,919	13	10,804	12
Wind 2018 + High EE	18,517	14	26,142	14	10,891	14

The Preferred Portfolio identified in the 2016 IRP (*Efficient Capacity 2021*) is the top ranked portfolio across all weighting sensitivities presented above.

PGE also tested the planning horizon and end effects sensitivities described in **Section 6.3** of these Reply Comments within this portfolio scoring framework sensitivity (with the 50% cost, 50% risk weights). Table 19 summarizes the findings.

TABLE 19. Scoring sensitivity (50% Cost, 50% Risk) under planning horizon and end effect sensitivities

Portfolio	20-year NPVRR (no end effects) Score	Rank	Infinite horizon NPVRR (constant real costs, 2051+) Score	Rank
Efficient Capacity 2021	11,013	1	27,503	1
Efficient Capacity 2021 - Min Bank	11,067	3	27,539	2
RPS Wind 2018	11,052	2	27,713	3
RPS Wind 2021	11,092	4	27,748	4
RPS Wind 2020	11,105	6	27,752	5
RPS Wind 2025	11,110	7	27,755	6
Wind 2018	11,093	5	27,799	7
Wind 2018 + Solar PV 2021	11,122	8	27,831	8
Wind 2018 Long	11,130	9	27,858	9
Geothermal 2021	11,139	10	27,876	11
Wind 2018 + Solar PV 2018	11,164	11	27,875	10
Boardman Biomass 2021	11,647	12	28,742	14
Efficient Capacity 2021 + High EE	12,162	13	28,188	12
Wind 2018 + High EE	12,230	14	28,462	13

Only small deviations in relative portfolio performance are observed under the NPVRR and end effect sensitivities. For example, while the *Efficient Capacity 2021* portfolio is the top performing portfolio under each sensitivity, the analysis shows that evaluating the NPVRR over a truncated 20-year horizon may flip the relative performance of the *RPS Wind 2018* and *Efficient Capacity 2021 – Min Bank* portfolios.

These sensitivity analyses described above supports the two primary portfolio findings identified in the 2016 IRP:

- Early RPS action provides a better combination of cost and risk than delayed RPS action (compare *Efficient Capacity 2021* to *Efficient Capacity – Min Bank* and *RPS Wind 2018* to *RPS Wind 2021*, *RPS Wind 2020*, and *RPS Wind 2025*); and
- Procurement of an efficient capacity (high capital cost, low variable cost) resource provides a better combination of cost and risk than procurement of a generic capacity (low capital cost, high variable cost) resource (compare *Efficient Capacity 2021* to *RPS Wind 2018*).

The findings also suggest that the portfolio score of the *Wind 2018 Long* portfolio is highly sensitive to the weight applied to risk. This finding comports with the expectation that additional wind resources, which reduce exposure to market risk, will be increasingly favored under weighting schemes that prioritize minimizing risk over minimizing cost.

Despite Parties' concerns with the scoring methodology applied in the 2016 IRP, PGE has shown that the findings in the 2016 IRP are robust to sensitivities around scoring methodology, weighting, and the NPVRR horizon.

7. Other

7.1. CO_2 Modeling

PARTIES' COMMENTS:

Sierra Club expresses concerns with PGE's modeling of the CO_2 price futures. Specifically, Sierra Club claims that the efficient capacity resource in the Preferred Portfolio is economically attractive in PGE's analysis because "the Company modeled the regional market as having a much higher carbon-intensity outside its territory, as a result of its assumption that western coal capacity will not change with different carbon prices or natural gas prices".[257] Sierra Club also claims that PGE "artificially inflated" the avoided emissions associated with the Preferred Portfolio by assuming constant emissions intensity for WECC in the carbon emissions reporting.[258]

PGE's RESPONSE:

PGE appreciates the opportunity to provide additional clarifying information regarding CO_2 modeling and CO_2 pricing in the 2016 IRP. Carbon emissions constraints and/or carbon prices are imposed both in the simulation of the WECC-wide capacity expansion and in PGE resource dispatch modeling. In these two modeling stages, which directly impact portfolio performance (cost and risk), PGE makes use of industry standard methodologies and assumptions to explicitly simulate carbon emissions across the West. In the PGE portfolio emissions reporting stage, which provides summary information, but does not impact portfolio scoring, PGE also relies on a reasonable and commonly accepted approximation of the emissions associated with market interactions.

7.1.1. *WECC-Wide Capacity Expansion Modeling*

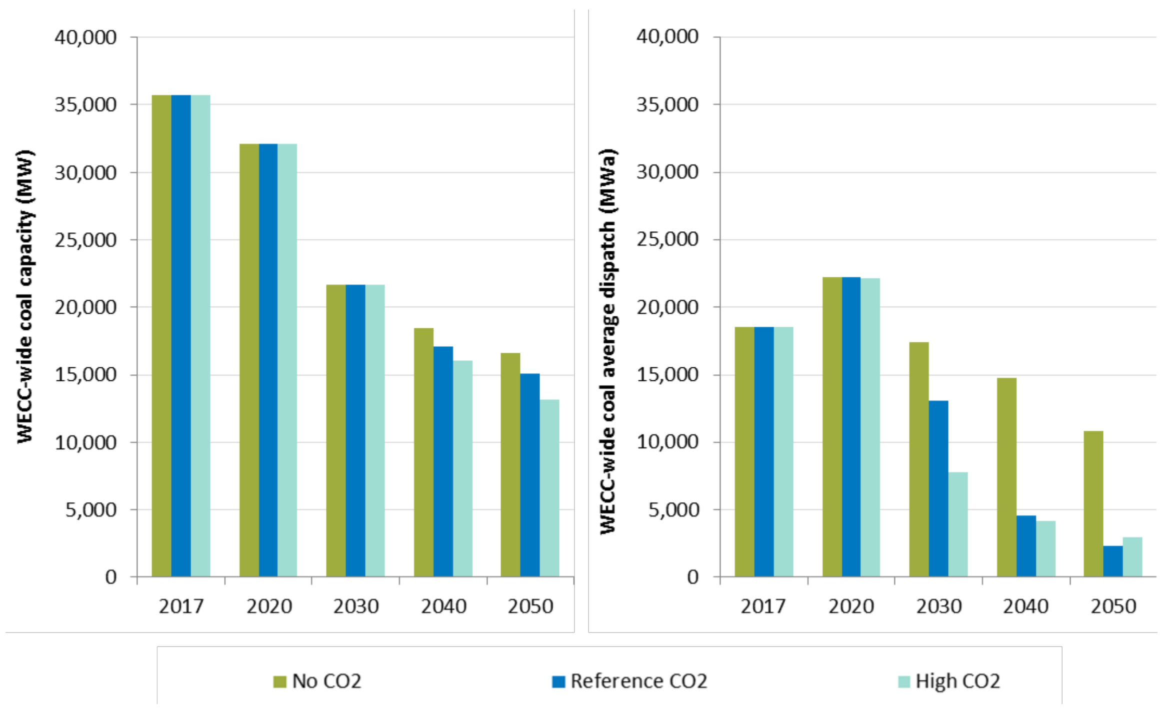
> ***Coal capacity modeled in the West reflects announced retirements and additional economic retirements associated with specific carbon price futures.***

The market prices modeled in the 2016 IRP reflect the dispatch of resources across WECC, and therefore depend on the incremental resources built (or retired) across the West both to meet load and to comply with relevant policies. PGE relies on the AURORA input database provided by Wood Mackenzie for the initial addition and retirement of plants across the West, which takes into account announced projects and retirements. PGE then runs separate capacity expansion model runs within AURORA corresponding to each carbon price future to determine the

[257] Sierra Club at 9.
[258] *Id.* at 18.

remaining capacity additions/retirements. In these runs, PGE applies RPS constraints, WECC-wide mass-based carbon emissions standards corresponding to the Clean Power Plan, and the carbon prices associated with the corresponding carbon price future. The carbon emissions across the WECC in this stage are modeled explicitly based on plant-specific emissions intensities and dispatch, not an exogenous WECC-wide emissions intensity approximation. PGE notes that while the AURORA capacity expansion modeling allows for the retirement of coal resources on an economic basis, the model does not choose to retire significantly different levels of coal capacity in different carbon futures. This was not a modeling assumption, as characterized by Sierra Club, but was instead a modeling result. Moreover, differences between futures seem small because coal retirements are massive in all futures: as Figure 15 shows, less than half of the current WECC coal capacity (35,000 MW in 2017) is still operating by 2040 in all futures. Importantly, coal dispatch changes across carbon price futures and is significantly reduced when higher carbon cost futures are simulated. As is described below in the dispatch modeling section, the carbon price future has therefore a significant impact on carbon intensity across WECC. Both the coal capacity and dispatch are summarized for the three carbon prices futures (and reference gas prices) in **Figure 15**.

FIGURE 15. WECC-wide coal capacity and dispatch solutions

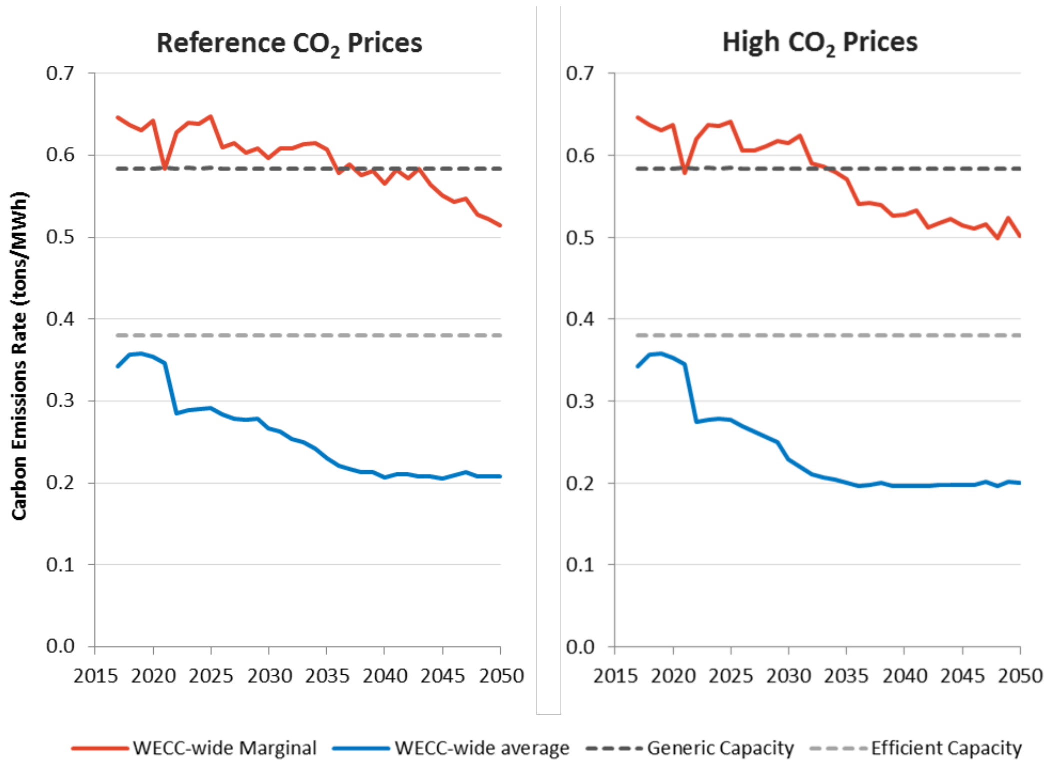


7.1.2. *PGE Resource Dispatch Modeling*

Resource dispatch and economics take into account resource-specific carbon emissions intensities for both PGE resources and resources across the West.

Both the market prices and dispatch behavior of PGE resources are determined through a second AURORA modeling step in which the WECC-wide resource fleet is fixed based on the capacity expansion modeling described above and resources across the WECC are dispatched in each hour to meet loads. In this modeling step, carbon emissions and Clean Power Plan constraints for the WECC are again explicitly modeled based on plant-specific emissions intensities and dispatch, not an exogenous WECC-wide emissions intensity approximation. Because each resource must purchase emissions allowances at the specified carbon price for each future, the market price calculated by the dispatch model in each hour reflects the carbon price and the emissions intensity of the marginal unit. PGE resources generally dispatch in time periods in which their marginal costs (including emissions costs) do not exceed the market price, barring operating constraints that prevent such a dispatch decision. The competitiveness of PGE resources in the market therefore depends on the heat rate (and emissions intensity) of the marginal unit, not the WECC-wide average emissions intensity. **Figure 16** shows the average and marginal emissions intensities in WECC, averaged across each year under the reference and high carbon price futures (with reference gas prices).

FIGURE 16. Average and marginal emissions rates



While the Efficient Capacity resource has a higher carbon emissions rate than the WECC-wide average emissions rate in both futures, its emissions rate is much lower than the annual average of the marginal emissions rates in each hour. This allows the Efficient Capacity resource to displace the higher heat rate and higher emitting generation that is dispatched on the margin, resulting in lower total emissions across the system.

7.1.3. *Carbon Emissions Reporting*

> ***The emissions rate applied to purchases/sales for carbon emissions reporting is a simplification and does not impact resource economics or portfolio scoring in the 2016 IRP.***

While the AURORA dispatch model takes into account the heat rates and emissions intensities of units when determining economic dispatch, it is not straightforward to specifically quantify the portion of the resulting WECC-wide emissions that is specifically associated with meeting PGE loads. Nevertheless, PGE attempted to summarize these emissions in the 2016 IRP in order to provide stakeholders with a broad understanding of how the actions modeled in the IRP impact carbon emissions.

While emissions accounting for PGE-owned and contracted resources are straightforward, emissions accounting for purchases and sales can take a number of forms. For example, in PGE's Investor-Owned Utility GHG report to the Oregon Department of Environmental Quality (DEQ) each year, PGE applies an Oregon DEQ-required default emissions factor to all purchases for which the originating generation source cannot be identified.[259] Alternatively, one could approximate the emissions rate of purchases and sales based on market prices (if gas is assumed to be on the margin), the emissions rate of the marginal unit in WECC, or the average emissions intensity across WECC. These methodologies would all yield different carbon emissions levels for the same fundamental dispatch and emissions across the West. For example, as shown in Figure 16, using the emissions rate of the marginal unit would result in much higher emissions than using the average emissions rate in years in which PGE is a net purchaser, which is the case for most years evaluated in the IRP.

PGE chose to use a fixed GHG emissions rate of 0.45 tons per MWh in the emissions reporting in the 2016 IRP for both purchases and sales as a simplifying assumption in part because it falls between the average and marginal emissions rates observed for WECC in the AURORA dispatch modeling. This is discussed on page 320 of the 2016 IRP and in PGE's response to Sierra Club Data Request No. 017. The Company considers this to be a reasonable assumption, but is open to exploring alternative accounting frameworks in future IRPs. However, PGE notes that because the dispatch cost calculations in AURORA explicitly model the emissions from individual units and take carbon pricing into account when dispatching those units, the chosen emissions accounting framework for carbon emissions reporting in the IRP has no bearing on portfolio economics or portfolio scoring.

7.2. Transmission

PARTIES' COMMENTS:

Several stakeholders comment on issues associated with procuring transmission for a potential Montana wind resource. Sierra Club contends that PGE's method of evaluating transmission costs for portfolios with Montana wind unreasonably precludes the Company from choosing

[259] See PGE's response to Sierra Club Data Request No. 017.

portfolios that would require new transmission.[260] NWEC expresses similar concerns.[261] Staff asks for more "high-level" information on the Montana wind option and its associated transmission constraints/options.[262] ICNU opines that the possibility of acquiring transmission rights for a Montana wind resource at a later date was a reason to justify delaying RPS action in the near-term.[263]

NIPPC criticizes the IRP because it does not consider the possibility of PGE converting its transmission service to network service on BPA's system.

PGE RESPONSE:

7.2.1. *Montana Wind Incremental Transmission Cost*

Overview

As a preliminary matter, Commissioners and the parties should understand that PGE's Action Plan is designed such that a Montana wind project will be able to bid into an RFP for renewable resources. All resources bidding into the RFP will have to include their own estimated interconnection and transmission costs. Therefore, PGE's transmission estimates for portfolio composition purposes have no bearing on whether or not a Montana wind resource (or any other resource) will ultimately be the winning bid in an RFP.[264] See, discussion in Reply Comments **Section 2**, *Action Plan*.

Nonetheless, PGE recognizes the impact that transmission costs may have on portfolio selection. PGE also recognizes that parties' concerns in this area are heightened because the 2016 IRP indicates that a portfolio with a Montana wind resource has the potential to have a substantially lower capital cost, due to a higher capacity factor and a higher capacity contribution than a PNW wind resource. Specifically, the portfolio results indicate approximately $474 million in present value benefits in the *Diverse Wind 2021* portfolio (which includes Montana wind) compared to the *Wind 2018* portfolio (which includes PNW wind). As discussed in Section 12.3.4 of the IRP, the *Diverse Wind 2021* portfolio does not capture additional transmission costs associated with delivering energy from Montana.[265] PGE modelled the differences in costs between the two portfolios to examine the potential present value benefits available to offset transmission and other costs necessary to deliver energy from a Montana wind resource while remaining competitive.[266]

In response to the concerns expressed by parties, PGE provides the following additional examination of hypothetical transmission cost cases for a Montana wind resource.

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[260] Sierra Club at 16.
[261] NWEC at 9.
[262] Staff at 40.
[263] ICNU at 18-19.
[264] See Reply Comments **Section 2**, *Action Plan*.
[265] In addition to costs associated with point-to-point (PTP) transmission rates or transmission upgrades, other costs may include additional transmission losses and additional transmission taxes (e.g., Montana Wholesale Energy Tax and Montana Beneficial Use Tax).
[266] 2016 IRP, Section 12.3.4

7.2.1.1. *Cost of Using Existing Transmission*

Acquisition of existing transmission rights, which are constrained, would offset much of the NPV benefit of the Diverse Wind portfolio

The following transmission options are the most direct routes to deliver energy from central Montana to PGE[267]:

1. Eastern Intertie/Montana Intertie[268]
2. NWMT System to BPAT or AVAT[269]

To PGE's knowledge, each option has an impact on BPA's West of Garrison or West of Hatwai flowgates.[270]According to BPA's posted long-term transmission availability reports, the West of Garrison flowgate has no available transfer capability (ATC) from 2018, the beginning of the current long-term ATC window, through 2027, the end of the current long-term window. The West of Hatwai flowgate has no ATC beginning in 2024.[271] For illustrative purposes, PGE examined simplified scenarios assuming 507 MW of available transmission rights for the routes above. The corresponding incremental cost to the *Diverse Wind 2021* portfolio on a NPV basis is estimated in the range of $300-$450 million, depending on assumptions (e.g., transmission losses, rate escalation). The estimated cost of the incremental transmission rights substantially reduces the benefit of a Montana wind resource compared to a PNW wind resource. This estimate ignores additional costs that would likely be incurred, including interconnection costs and taxes.

7.2.1.2. *Potential Costs of Using New Transmission*

New transmission makes the Diverse Wind portfolio significantly more costly than the Preferred Portfolio.

As discussed in Section 9.2 of the 2016 IRP, regional transmission planning is conducted through the Northern Tier Transmission Group and the Columbia Grid. Both entities have a role in planning for future transmission projects which may impact the ability to move power from Montana to BPA or PGE's systems.[272] To date, PGE is unaware of any plans that have been

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[267] There may be other transmission options for delivery of Montana Wind to PGE. However, to the best of PGE's knowledge, these options entail multiple transmission paths, with varying degrees of constraints, and therefore additional costs.
[268] This path consists of the following transmission paths: Broadview to Townsend and Townsend to Garrison.
[269] This path assumes a direct connection to the NWMT transmission system without any intermediary transmission providers.
[270] https://transmission.bpa.gov/Business/Operations/Paths/PathMap_Feb12.pdf
[271] https://www.bpa.gov/transmission/Reports/TransmissionAvailability/Documents/long_term_atc.xls
[272] The NTTG completed a Study Report for the 2014-2015 Public Policy Consideration Scenario that examined a scenario in which Colstrip Units 1&2 were retired and replaced with a wind resource. The study is available on the NTTG website (nttg.biz). RNW and NWEC requested an additional study, which has not been completed at this time.

finalized to increase the east-to-west transmission capacity from Montana, much less any projects that have begun construction.

While PGE cannot speculate as to what, if any, specific projects and associated costs may result from the regional transmission planning process, PGE notes that the capital costs associated with large regional transmission projects can be substantial. A Transmission Expansion Planning Policy Committee (TEPPC) report prepared by Black & Veatch (B&V) estimates a baseline capital cost of roughly $3 million per mile for a double circuit 500 KV line in 2014.[273] This is prior to adjustments for things such as terrain (mountains and forests increase the cost by factors ranging from 1.75 to 2.25) and it does not include the cost of other items such as substations. PGE also notes that large regional transmission projects typically have long lead times – often close to ten years. Additionally, upgrade costs can be directly assigned to the party requesting the upgrades or new transmission. These upgrade costs are in addition to the monthly payments made to the transmission provider at the posted tariff rate.

In its 2015 IRP, Puget Sound Energy (PSE) examined multiple transmission cost scenarios for a wind resource located in Montana, including scenarios with the retirement of Colstrip Units 1&2.[274] While these sensitivities were not part of PSE's IRP portfolio analysis, the costs of all scenarios appear to be substantial.[275]

7.2.2. *Future Acquisition of Transmission*

Speculation as to future availability of transmission should not justify forgoing significant PTC benefits.

In response to ICNU's suggestion that the possibility of acquiring transmission rights for a Montana wind resource at a later date is a reason to justify delaying RPS action, PGE points out that the future availability of transmission rights from Montana, and the cost to procure and use those rights, is highly speculative and an RPS delay would likely preclude capturing PTC benefits (see **Section 3** of this document for a discussion of PTC benefits). Further, PGE notes that in order to meet RPS requirements, additional RPS resources will be needed beyond the actions requested in this IRP (all IRP portfolios include RPS additions in later years, as seen in Appendix O). If, transmission from Montana were to become available and cost-effective at a later date, it could be used for later resource additions.

7.2.3. *Network Integration Transmission Service (NITS)*

NIPPC's suggestion that the IRP should contemplate conversion to BPA Network Integrated Transmission Service is without merit.

[273] Table 2-1, https://www.wecc.biz/Reliability/2014_TEPPC_Transmission_CapCost_Report_B+V.pdf]
[274] PGE is not a co-owner of Colstrip Units 1and 2 and has no rights to the transmission used to move power from Colstrip 1&2 to the PNW. PGE does have transmission rights used to move a portion of its Colstrip Units 3 and4 share.
[275] *See* Puget Sound Energy, 2015 Integrated Resource Plan, at 6-76 and Appendix D. Accessed March 27, 2017: https://pse.com/ABOUTPSE/ENERGYSUPPLY/Pages/Resource-Planning.aspx

NIPPC suggests that the Commission should require PGE to consider converting its Point-to-Point (PTP) service on Bonneville's transmission system to Network Integration Transmission Service ("NITS").[276] NIPPC presents an analysis of the respective costs of PTP and NITS, concluding that PGE and its ratepayers could save roughly $15 million per year from that conversion. However, NIPPC's proposal and analysis are flawed for several reasons, and the Commission should reject conversion to NITS as a viable option for PGE in the IRP process.

First, PTP service and NITS are not comparable. Unlike NITS, PTP rights are flexible, redirectable, and resellable, allowing PGE to both meet its load needs and to use its portfolio of generation more efficiently by making off-system sales.[277] In a region with significant wind and hydropower penetration, being able to economically sell or purchase market power is a necessity. PGE uses its BPA PTP service to optimize its portfolio of generation with market purchases and sales to reduce net variable power costs. In addition to being limited to imports or use for native load service, NITS also includes a redispatch requirement, giving BPA potential control over PGE resources and complicating PGE's own BAA balancing operations.[278] NIPPC paints aspects of NITS as preferable to PTP, arguing that it would "significantly reduce PGE's ability to discriminate against non-utility owned generation." This framing casts NITS in a far rosier light than the facts actually support. Moreover, NIPPC provides no evidence of undue discrimination and its inference that there is a seemingly unlimited supply of transmission capacity at no incremental cost under NITS is simply false.[279]

Second, NIPPC's analysis assumes savings, without conducting needed analysis of related costs. This results in skewed figures favoring NITS over PTP. Because NITS is a more "static" service, if PGE were to transfer 100% of its present transmission service to NITS, it would almost certainly need to purchase additional PTP capacity to ensure the operational benefits discussed above. Section 28.6 of BPA's OATT makes this clear: "All Network Customers taking Network Integration Transmission Service *shall* use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System." This requirement, coupled with the unquestionable need to retain some amount of transmission capability allowing for third-party sales, would reduce the "savings" that NIPPC contends would result from its proposed switch to NITS. In addition to this reduction to NIPPC's purported "savings," NIPPC, without any support, overstates PGE's BPA PTP transmission position by approximately 700 MW, which, if this alone is corrected in NIPPC's analysis, reduces the purported annual savings to approximately $0.[280]

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[276] NIPPC Comments at 17-23.
[277] *See* BPA OATT at 28.6, "Restrictions on Use of Service" regarding NITS: "The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System."
[278] BPA OATT at 30.5.
[279] "If PGE were to convert its existing transmission service to NITS, it could obtain any and all incremental future transmission…at no incremental cost" NIPPC Comments at p.21.
[280] PGE only pays monthly service fees for its active reservations. PGE provided details of its active point-to-point reservations as of January 1, 2017 in its Response to NIPPC Data Request No. 037.

In addition to the fact that PGE's continuing need for PTP service (and associated costs) would reduce NIPPC's savings estimate, another significant problem with NIPPC's analysis is that the alleged $15 million in savings is illusory in the first place. BPA sets its transmission rates based on its costs.[281] If $15 million in BPA revenues vanish due to PGE switching from PTP to NITS, BPA would necessarily have to recover those costs elsewhere – by raising network rates, PTP rates, or otherwise charging transmission customers. NIPPC essentially assumes that a switch from PTP to NITS is a "free lunch" for PGE and its customers (with only savings and no countervailing costs), which is obviously not the case. To the extent that NIPPC insists on analyzing predicted costs of PGE converting its transmission service, that analysis must reflect the actual circumstances of BPA's transmission rate-making process and the associated revenue requirement.

Third, using NITS on the BPA system is incompatible with transfers into the Energy Imbalance Market. PGE is slated to begin market operations on October 1, which will result in 15-minute and 5-minute transfers between the PGE, PacifiCorp West, and CAISO Balancing Authority Areas ("EIM Transfers"). As part of its market participation, PGE will make portions of its transmission rights available on BPA's system to facilitate EIM transfers, as BPA customer Puget Sound Energy does today. Because an EIM transfer is a transfer/sale of energy to or from one EIM Entity to another EIM Entity, NITS is fundamentally incompatible with this sort of transfer unless BPA were to become an EIM Entity (which, at present, it shows no sign of seriously contemplating). Analysis conducted prior to pursuing EIM membership identified substantial benefits to PGE customers, estimated at a minimum of $3.5 million per year (and likely higher).[282] These benefits are dependent upon PGE having the transmission necessary to engage in EIM transfers and a transmission portfolio that is comprised solely of NITS is incompatible with EIM participation.

Fourth and finally, NIPPC's proposal would change a BPA exception to a rule, with uncertain results. NITS is fundamentally designed for use by transmission customers within a transmission provider's control area. Although FERC's *pro forma* OATT and BPA's OATT allow for load outside of the control area to be designated as network load,[283] to PGE's knowledge this is used only in limited circumstances for small preference customers of BPA or, in the case of PacifiCorp, for stranded load pockets in BPA's BAA. These exceptions can be technically challenging to implement, and the off-system NITS option is completely untested for a hypothetical off-system "network load" of PGE's scale. Converting all of PGE's PTP transmission rights on BPA's system to NITS would drastically expand the use of off-system NITS, likely requiring significant deliberations with BPA on an uncertain time frame relative to other aspects incorporated into the IRP.

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[281] *See* https://www.bpa.gov/finance/ratecases/pages/default.aspx: "BPA is a self-financed Federal agency. This means that BPA does not receive appropriations or tax dollars for operations and maintenance. BPA pays its expenses from revenues it receives from the sale of power and transmission services to eligible customers."

[282] https://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14054757, at Attachment A – E3 economic analysis. The $3.5 million was the lower bound, with savings estimates of up to $6.1 million per year in a "high RPS" scenario.

[283] BPA OATT at 31.3, "Network Load not Physically Interconnected with the Transmission Provider." https://www.bpa.gov/transmission/Doing%20Business/Tariff/Documents/bpa_oatt.pdf

7.3. Distribution Planning

PGE supports efforts to align the various regulatory processes related to distribution planning and is willing to work with Staff and others on this effort.

OPUC Staff raised a number of questions related to how distribution planning can be aligned with other regulatory planning process, including the IRP process, and how distributed energy resources (DERs) should be accounted for in IRPs.[284] PGE supports efforts to align the various regulatory processes related to distribution planning and is willing to work with Staff and others on this effort. PGE is also open to suggestions for improved assessment of DERs in its IRP.

7.4. North Mist Expansion

PGE provides additional information on the North Mist Expansion

In its comments, Staff notes that it is reviewing PGE's stated gas needs and whether the specifications for the North Mist Expansion Project (NMEP) are reasonable to meet PGE's gas storage, service and delivery needs.[285]

As Staff continues its review of the NMEP specifications, PGE believes the following details should be kept clear. First, a "North Mist" gas storage facility does not exist. Since 2007, PGE has received firm natural gas storage service from NW Natural that allows PGE to store up to 1.26 million dekatherms (and withdraw up to 70,000 dekatherms per day) of natural gas in the Mist gas storage facility near Clatskanie, Oregon. This capacity at Mist is subject to recall by NW Natural, and in the future, NW Natural intends to use its existing Mist storage to serve its core customers.[286] PGE's Mist gas storage agreement would expire in April 2017, but for the NMEP, and NW Natural was not able to offer PGE another long-term agreement at Mist. As a result of the NMEP, PGE's service from Mist will now conclude shortly after NMEP is placed into service.

Second, the NMEP is a unique underground storage facility. It does not add storage capacity to NW Natural's existing Mist storage. In its 2013 IRP, PGE identified the Precedent Agreement with NW Natural to construct the NMEP to provide no-notice withdrawal firm storage service to the Port Westward/Beaver complex. The NMEP replaces the storage needs previously provided from Mist storage with more flexible service and increases PGE's gas storage to meet the fueling requirements of the Port Westward/Beaver complex.

Finally, under the Precedent Agreement, NW Natural will construct the NMEP to provide no-notice service to the Port Westward/Beaver complex. As part of the Precedent Agreement, PGE and NW Natural will enter into an Oregon Storage Service Agreement (OSSA). The OSSA sets forth the maximum injection, maximum withdrawal, and maximum storage quantities provided to PGE. As part of the OSSA, NW Natural will provide no-notice withdrawal firm storage

[284] Staff at 33-38.
[285] Staff at 24.
[286] *See,* NW Natural's 2014 Integrated Resource Plan at 1.10 (providing a description of Mist Recall). Commission Order No. 15-064 acknowledged NW Natural's 2014 Integrated Resource Plan.

service for 30 years, with possible extensions for a cumulative service term of 80 years. NW Natural will finance and construct the facility and provide service to PGE under NW Natural Rate Schedule 90. Service under the agreement will be at cost-based rates.

As described in its 2016 IRP, gas storage, in geographical proximity to a generating plant, (when compared to firm pipeline transportation) provides much greater fueling flexibility for gas-fired resources.[287] This fueling flexibility is integral to PGE's ability to provide flexible capacity, which relies on a highly flexible and dynamic fuel supply to meet the demands for contingencies on the system, load following, and regulation services.

8. Compliance with IRP Guidelines

PGE has fully complied with the Commission's IRP Guidelines

Some parties contend that PGE may not have complied with some of the Commission's IRP Guidelines as set forth in OPUC Order No. 07-002.[288] In many cases, Staff claims that PGE did not comply with a Guideline because it did not provide enough information. For example, Staff suggests that PGE did not comply with Guideline 4b because it did not provide enough information about the assumptions used in its load forecast. Likewise at the February 16, 2017 Commission workshop, Staff claimed that PGE did not provide enough analysis on resources of different durations.

PGE provided all of the information and analyses required by the Commission's IRP Guidelines and relevant orders. PGE included as Appendix A in the IRP, a table identifying each of the Commission's IRP Guidelines and where in the IRP PGE complies with each Guideline. The extent of the information and analyses provided in the IRP is commensurate with, and often greater than, information and analyses provided in past IRPs. PGE has provided even more information and analyses in these Reply Comments. **Table 20** below identifies the sections of these Reply Comments in which PGE expands further on its compliance with the Guidelines.

[287] *See* PGE's 2016 IRP at 84.
[288] Staff Public Meeting Comments; Staff Initial Comments at 5, 15, 17, and 27; NWEC at 2-3; Sierra Club at 3-4.

TABLE 20. Commission Guideline Compliance in PGE's Reply Comments

OPUC Guideline	Reply Comments Section
Guideline 1c	
Requires utilities to identify a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for PGE and its customers.	2, 6.4
Requires analysis of resources of different durations	5.3.2
Requires the planning horizon for analyzing resource choices to be at least 20 years and account for end effects. It directs utilities to consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	6.3
Requires that the plan include, at a minimum: 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes	6.4.3, 6.4.4
Guideline 1d	
Action Plan must be consistent with the long-run public interest	3.5
Guideline 4b	
Requires analysis of high and low load growth, stochastic load risk, and an explanation of load forecast drivers.	4.1.1, 4.1.4
Guideline 4n	
Requires the IRP to provide an Action Plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources with the key attribute of each resource specified as in portfolio testing.	2
Guideline 12	
Requires utilities to evaluate distributed generation technologies on par with other supply-side resources	5.5
Guideline 13a	
Requires the utility to identify its proposed acquisition strategy for each resource in its Action Plan and to "assess the advantages and disadvantages of owning a resource instead of purchasing power from another utility	2.3

9. Conclusion

In reviewing an IRP, the Commission considers the extent to which the plan satisfies the procedural and substantive requirements of Oregon's IRP Guidelines. It acknowledges or does not acknowledge specific action items based on the reasonableness of those actions with the information available at the time the utility filed its IRP.[289] As discussed in PGE's 2016 IRP and throughout these Reply Comments, PGE's 2016 IRP satisfies the procedural and substantive requirements of Oregon's IRP Guidelines. Moreover, it offers an Action Plan that, consistent with past Commission direction, maintains flexibility in the types of technologies that can be acquired under an RFP, but provides specificity as to the operating characteristics that will be sought. PGE conducted numerous additional analyses and sensitivities to respond to concerns raised in Parties' opening comments. These new analyses and sensitivities continue to show that the 2016 IRP Action Plan offers the best balance of least cost and lowest risk for PGE's customers.

DATED this 31st day of March, 2017.

Respectfully submitted,

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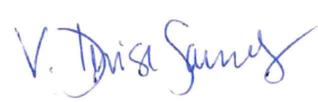


[289] Order 16-071 at 2.

10. Attachments

Attachment A.	Wells Contract Details
Attachment B.	RPS Analysis Supplemental Information
Attachment C.	Staff's Response to PGE's Data Request 002
Attachment D.	PGE PTC Carryforward Analysis (CONFIDENTIAL TABLES 3 - 9)
Attachment E.	LBNL Response to PGE, March 24, 2017
Attachment F.	Individual Customer Forecast Sensitivity (CONFIDENTIAL – Staff only)
Attachment G.	Energy Trust Response to PGE RE: 10% Conservation Adder, March 23, 2017 Email
Attachment H.	PGE's Response to Staff's Data Request No. 074
Attachment I.	NPVRR Sensitivities Across Futures
Attachment J.	PGE's Summary of Reply Comments

On March 29, 2017, PGE executed a 10-year Power Purchase Agreement (PPA), beginning September 1, 2018, with Douglas County Public Utility District (PUD) for output from the Wells Hydroelectric Project (Wells). Under the new PPA, PGE will receive a share (slice), which is dependent on the hydro conditions and forecasted non-PGE loads, of the capacity and energy produced at Wells. Based on average hydro conditions and projected load growth, PGE's anticipated average share at the beginning of the PPA term, September 1, 2018, is approximately 130-160 MW of capacity and 60-70 MWa of energy, depending on the month. PGE's expected average share is forecasted to steadily decline over the duration of the PPA and anticipated to be approximately 90-140 MW of capacity and 40-100 MWa of energy at the end of the PPA term, September 30, 2028.[1] PGE is currently evaluating the impact of this PPA on the remaining 2021 capacity shortage and will provide an update to the Commission and Parties.

[1] PGE's share is based on a seasonal allocation determined each year and applied to the actual capacity and energy available at the project.

RPS Analysis Supplemental Information

In this attachment, PGE provides summaries of each of the portfolios described in the supplemental RPS analysis discussed in PGE's Reply Comments and the relative NPVRR results across futures for the timing and PTC eligibility sensitivities. The portfolio summaries include the following information:

Portfolio Name – Used for tracking portfolios in work papers, does not appear in the Reply Comments

COD – The commercial online date (year) associated with the earliest RPS addition in the portfolio. For Delay Portfolios, the COD of the earliest RPS addition varies depending on the load and minimum REC bank assumptions, so these portfolios are indicated with the word "Delay" in the COD field.

Addition Size – The size in MWa of the earliest RPS addition in the portfolio. For Delay Portfolios, the size of the earliest RPS addition varies depending on the load and minimum REC bank assumptions, so this field is left blank.

Minimum REC Bank Assumption – this is the minimum allowed REC bank balance in each year. Portfolios are designed to ensure that there are enough RECs in the bank by the end of 2035 and 2040 to meet this constraint. There were three minimum REC bank sensitivities investigated in PGE's Reply Comments:

- *2016 IRP Assumption* – In these portfolios, the minimum REC bank assumption reflect ed the constraint applied to portfolio construction in the 2016 IRP. This constraint considered 1.5 years of risk associated with load levels, variable renewable generation, and procurement failure and was fixed across all portfolios. This constraint is summarized below.

Table 1. Minimum REC bank constraint – 2016 IRP Assumption

Minimum REC Bank (MWa)	2020	2025	2030	2035	2040
2016 IRP Assumption	194	406	549	746	730

- *Minimum REC Bank Sensitivity* – In these portfolios, PGE reduced the minimum REC bank to account for only one year of risk associated with load levels and variable renewable generation and included no treatment of procurement risk. In addition, the minimum REC bank sensitivity calculated a constraint that was dynamic with the RPS additions in the portfolio. This constraint is summarized below for the five portfolios in which it was applied.

Table 2. Minimum REC bank constraints – Minimum REC Bank Sensitivity

Portfolio			Minimum REC Bank (MWa)				
Portfolio Name	COD	Addition Size (MWa)	2020	2025	2030	2035	2040
Supp_2018_175	2018	175	122	120	122	199	274
Supp_2019_175	2019	175	122	120	122	207	274
Supp_2020_175	2020	175	122	120	122	215	274
Supp_2021_175	2021	175	83	120	122	223	274
Supp_Delay	Delay		83	82	174	240	274

- *Zero* – In these portfolios, no minimum REC bank constraint was applied.

Load Assumption – PGE considered two sensitivities to the load forecast used in the 2016 IRP in the supplemental RPS analysis:

- *December 2016 Forecast* – In these portfolios, the RPS obligation and remaining capacity need correspond to the December 2016 load forecast described in Section 4.1 of PGE's Reply Comments.
- *Zero Load Growth* – In these portfolios, the RPS obligation and remaining capacity need correspond to a load that has zero growth beginning in 2017. In these portfolios, the 2017 load assumption is also based on the December 2016 load forecast.

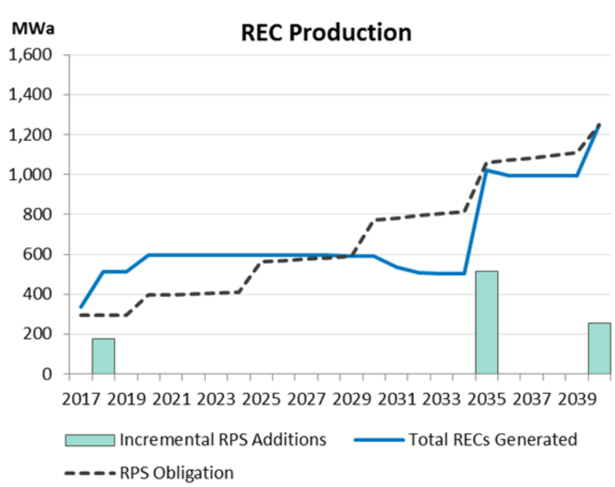
Relative NPVRR Analysis

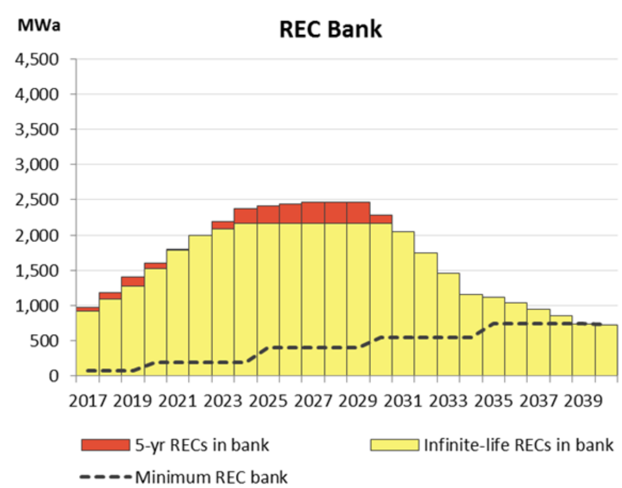
The supplemental RPS analysis in PGE's Reply Comments includes the relative NPVRR differences between various supplemental RPS portfolios. These relative NPVRR values were determined by isolating the cost impacts specific to the differences between the portfolios, including: the fixed and variable costs and market value of renewable resources added between 2018 and 2040; and the fixed and variable costs and market value of the generic capacity resources added between 2018 and 2040. All other portfolio resources (and their associated costs and market revenues) are fixed across all portfolios and are therefore not included in the relative NPVRR calculation. To calculate the generic capacity additions in each year, PGE used the RECAP model to determine remaining capacity shortages in each year after accounting for RPS additions. This is the same methodology used in the 2016 IRP to determine generic capacity additions. PGE validated the relative NPVRR calculations by replicating portfolio cost differences between RPS portfolios in the IRP and comparing these differences to the corresponding AURORA outputs. This validation exercise yielded differences of less than $1 million on a 2016 NPV basis between the calculation used for the Supplemental RPS Analysis and the AURORA portfolio output data

B.1. Supplemental RPS Portfolios

Portfolio Name	Supp_2018_175
COD	2018
Addition Size (MWa)	175
Minimum REC Bank Assumption	2016 IRP Assumption
Load Assumption	December 2016 Forecast

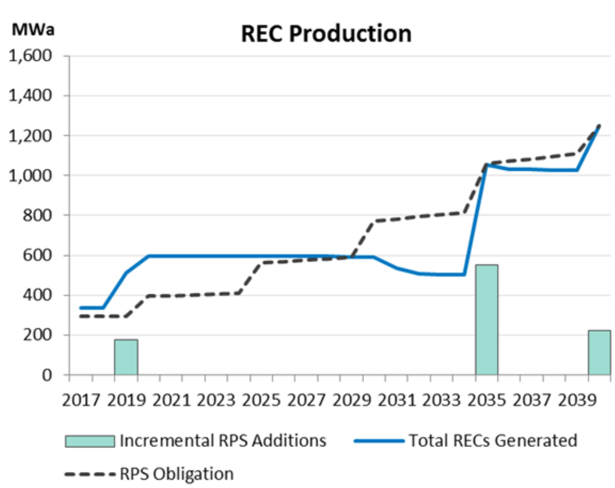
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	76
2018	175	513	295	89	1,098	76
2019	175	513	295	132	1,273	76
2020	175	597	396	75	1,527	194
2021	175	597	399	16	1,789	194
2025	175	597	563	245	2,166	406
2030	175	589	774	123	2,166	549
2035	691	1,021	1,057	0	1,118	746
2040	948	1,251	1,251	0	730	730

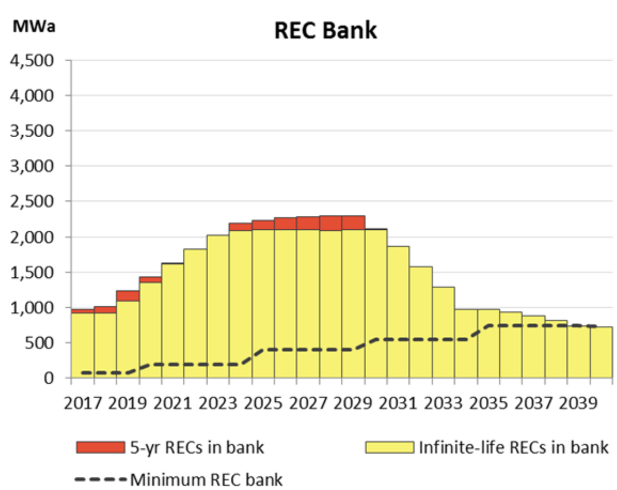




Portfolio Name	Supp_2019_175
COD	2019
Addition Size (MWa)	175
Minimum REC Bank Assumption	2016 IRP Assumption
Load Assumption	December 2016 Forecast

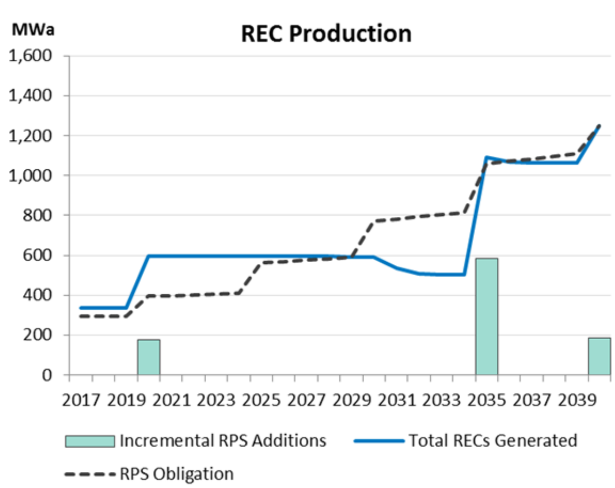
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	76
2018	0	338	295	89	923	76
2019	175	513	295	132	1,098	76
2020	175	597	396	75	1,352	194
2021	175	597	399	16	1,614	194
2025	175	597	563	138	2,098	406
2030	175	589	774	15	2,098	549
2035	726	1,056	1,057	0	978	746
2040	948	1,251	1,251	0	730	730

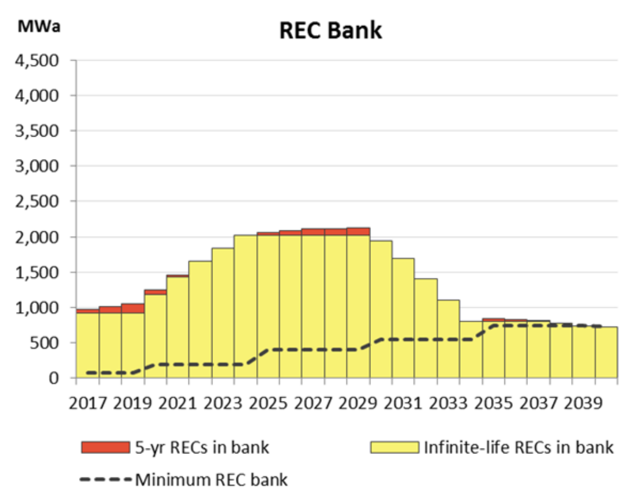




Portfolio Name	Supp_2020_175
COD	2020
Addition Size (MWa)	175
Minimum REC Bank Assumption	2016 IRP Assumption
Load Assumption	December 2016 Forecast

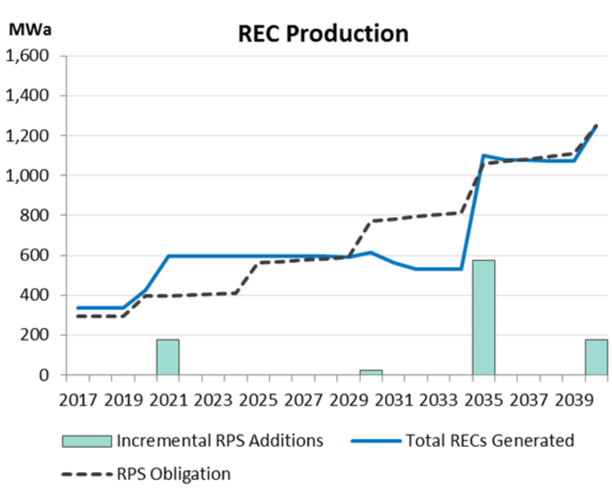
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	76
2018	0	338	295	89	923	76
2019	0	338	295	132	923	76
2020	175	597	396	75	1,178	194
2021	175	597	399	16	1,439	194
2025	175	597	563	35	2,026	406
2030	175	589	774	0	1,939	549
2035	761	1,091	1,057	34	804	746
2040	948	1,251	1,251	0	730	730

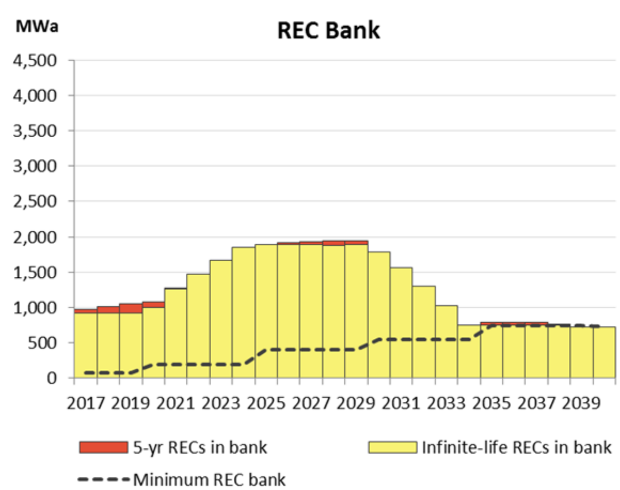




Portfolio Name	Supp_2021_175
COD	2021
Addition Size (MWa)	175
Minimum REC Bank Assumption	2016 IRP Assumption
Load Assumption	December 2016 Forecast

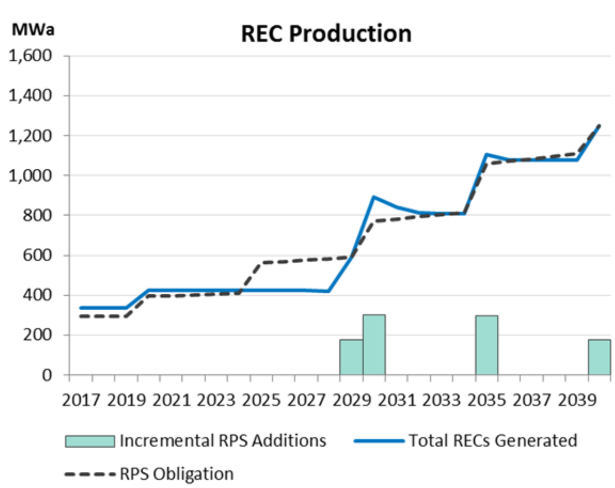
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	76
2018	0	338	295	89	923	76
2019	0	338	295	132	923	76
2020	0	422	396	75	1,003	194
2021	175	597	399	16	1,263	194
2025	175	597	563	0	1,886	406
2030	199	613	774	0	1,787	549
2035	772	1,102	1,057	45	748	746
2040	948	1,251	1,251	0	730	730

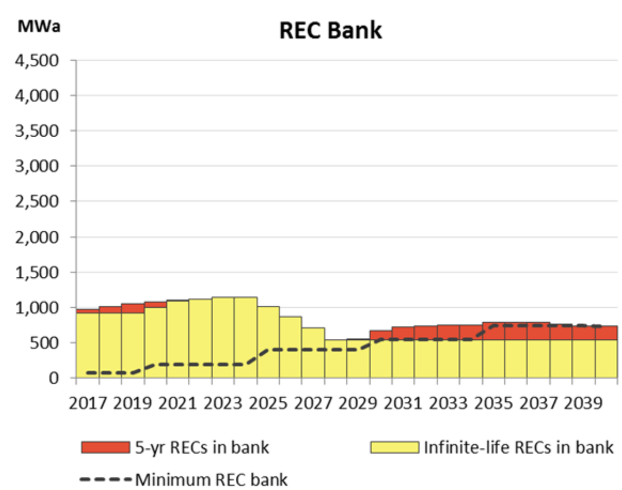




Portfolio Name	Supp_Delay
COD	Delay
Addition Size (MWa)	
Minimum REC Bank Assumption	2016 IRP Assumption
Load Assumption	December 2016 Forecast

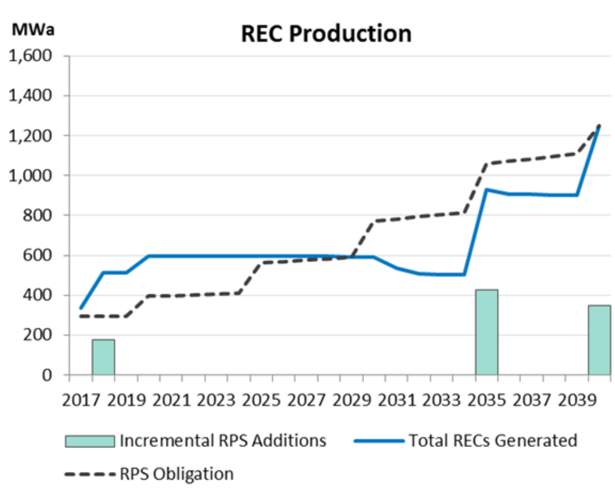
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	76
2018	0	338	295	89	923	76
2019	0	338	295	132	923	76
2020	0	422	396	75	1,003	194
2021	0	422	399	16	1,088	194
2025	0	422	563	0	1,010	406
2030	478	892	774	121	547	549
2035	773	1,103	1,057	245	547	746
2040	948	1,251	1,251	187	546	730

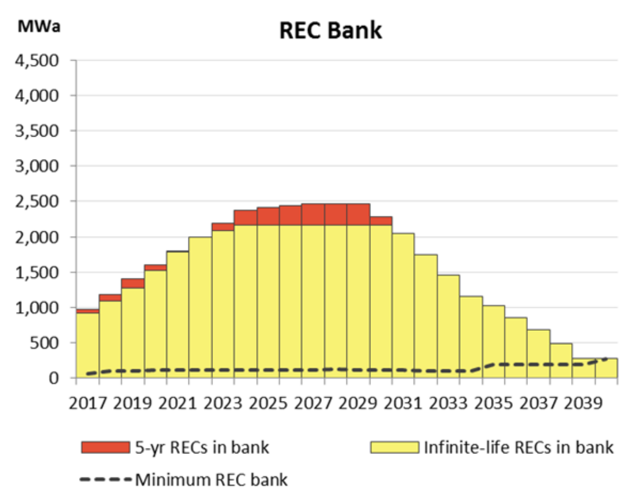




Portfolio Name	Supp_2018_175_RBS
COD	2018
Addition Size (MWa)	175
Minimum REC Bank Assumption	Low Sensitivity
Load Assumption	December 2016 Forecast

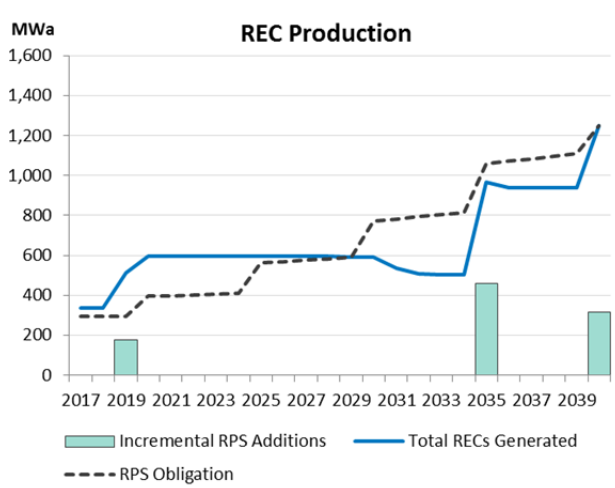
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	61
2018	175	513	295	89	1,098	102
2019	175	513	295	132	1,273	102
2020	175	597	396	75	1,527	122
2021	175	597	399	16	1,789	119
2025	175	597	563	245	2,166	120
2030	175	589	774	123	2,166	122
2035	600	930	1,057	0	1,026	199
2040	948	1,251	1,251	0	274	274

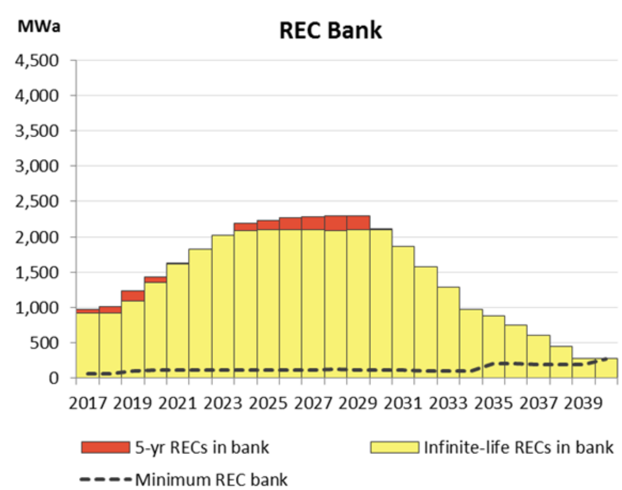




Portfolio Name	Supp_2019_175_RBS
COD	2019
Addition Size (MWa)	175
Minimum REC Bank Assumption	Low Sensitivity
Load Assumption	December 2016 Forecast

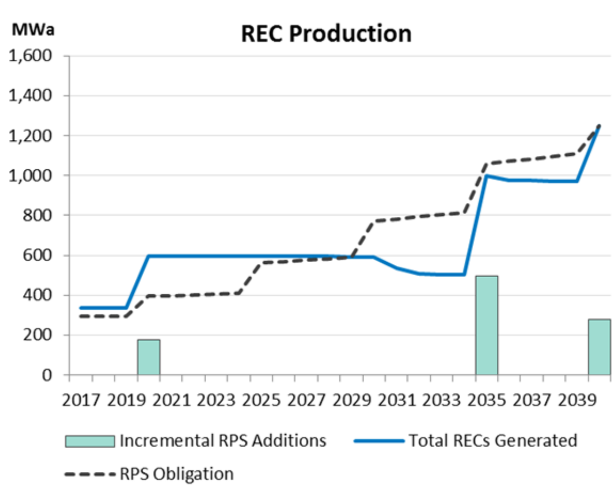
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	61
2018	0	338	295	89	923	63
2019	175	513	295	132	1,098	102
2020	175	597	396	75	1,352	122
2021	175	597	399	16	1,614	119
2025	175	597	563	138	2,098	120
2030	175	589	774	15	2,098	122
2035	635	965	1,057	0	887	207
2040	948	1,251	1,251	0	276	274

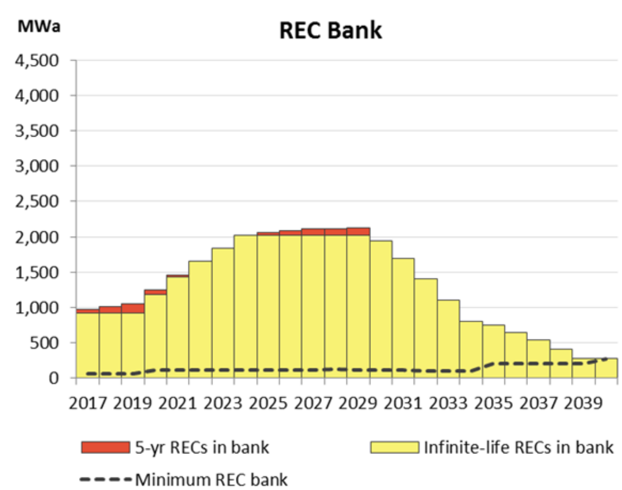




Portfolio Name	Supp_2020_175_RBS
COD	2020
Addition Size (MWa)	175
Minimum REC Bank Assumption	Low Sensitivity
Load Assumption	December 2016 Forecast

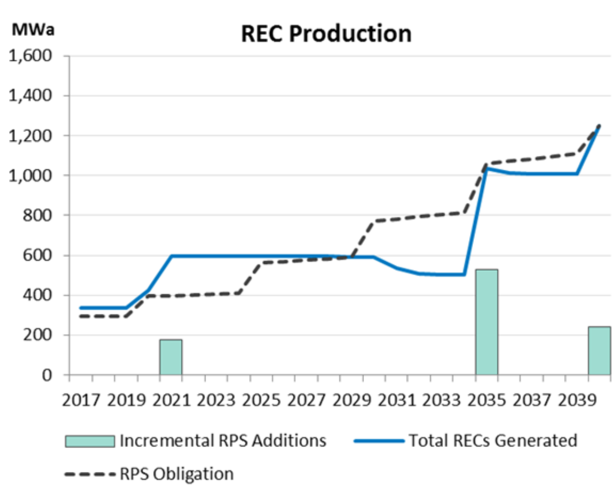
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	61
2018	0	338	295	89	923	63
2019	0	338	295	132	923	63
2020	175	597	396	75	1,178	122
2021	175	597	399	16	1,439	119
2025	175	597	563	35	2,026	120
2030	175	589	774	0	1,939	122
2035	670	1,000	1,057	0	746	215
2040	948	1,251	1,251	0	274	274

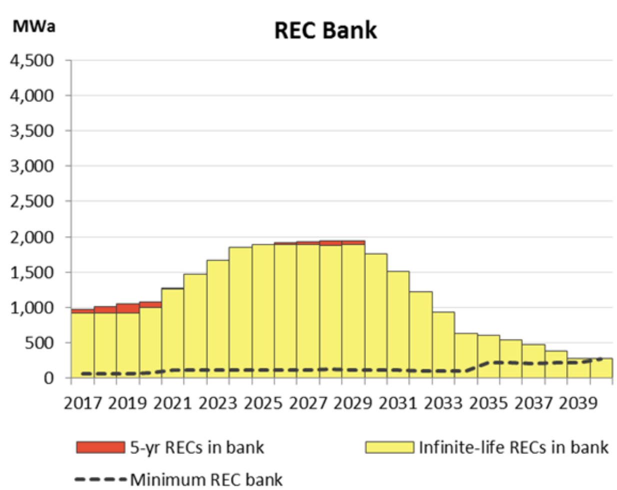




Portfolio Name	Supp_2021_175_RBS
COD	2021
Addition Size (MWa)	175
Minimum REC Bank Assumption	Low Sensitivity
Load Assumption	December 2016 Forecast

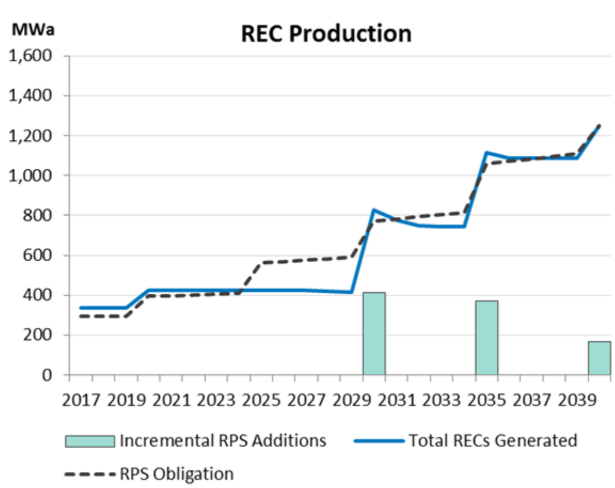
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	61
2018	0	338	295	89	923	63
2019	0	338	295	132	923	63
2020	0	422	396	75	1,003	83
2021	175	597	399	16	1,263	119
2025	175	597	563	0	1,886	120
2030	175	589	774	0	1,763	122
2035	705	1,035	1,057	0	606	223
2040	948	1,251	1,251	0	276	274

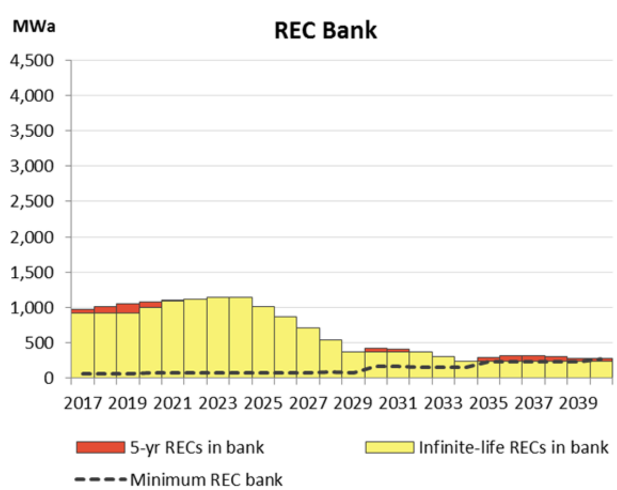




Portfolio Name	Supp_Delay_RBS
COD	Delay
Addition Size (MWa)	
Minimum REC Bank Assumption	Low Sensitivity
Load Assumption	December 2016 Forecast

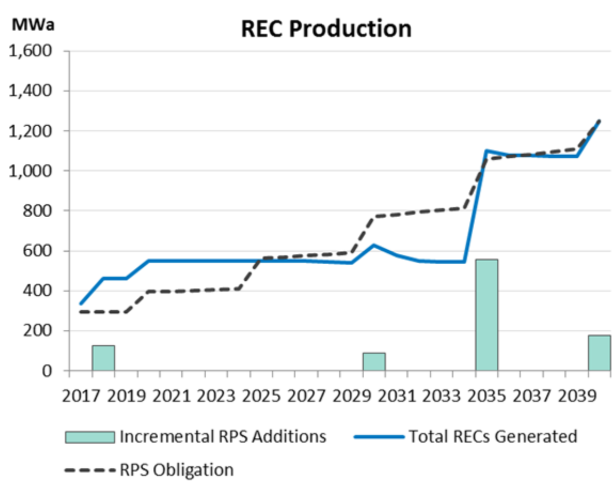
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	61
2018	0	338	295	89	923	63
2019	0	338	295	132	923	63
2020	0	422	396	75	1,003	83
2021	0	422	399	16	1,088	81
2025	0	422	563	0	1,010	82
2030	413	827	774	53	372	174
2035	782	1,112	1,057	55	243	240
2040	948	1,251	1,251	34	242	274

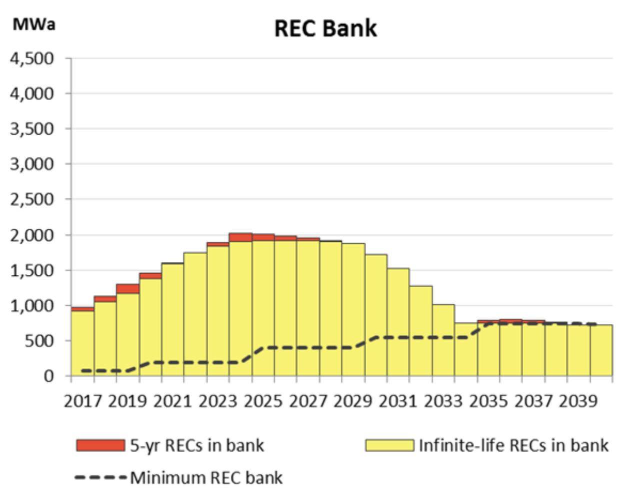




Portfolio Name	Supp_2018_125
COD	2018
Addition Size (MWa)	125
Minimum REC Bank Assumption	2016 IRP Assumption
Load Assumption	December 2016 Forecast

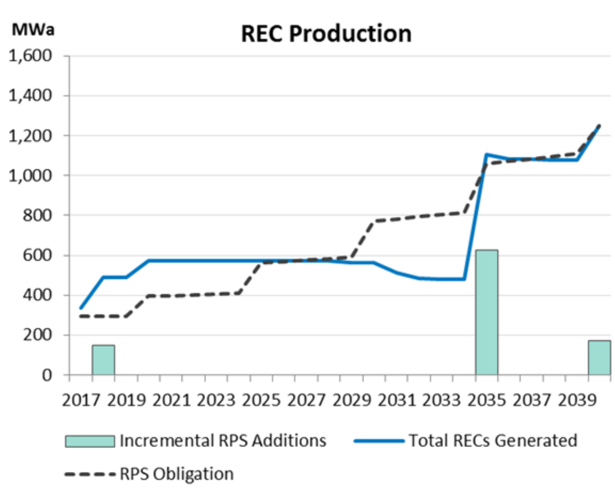
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	76
2018	125	463	295	89	1,048	76
2019	125	463	295	132	1,173	76
2020	125	547	396	75	1,377	194
2021	125	547	399	16	1,589	194
2025	125	547	563	95	1,916	406
2030	214	628	774	0	1,727	549
2035	772	1,102	1,057	45	748	746
2040	948	1,251	1,251	0	730	730

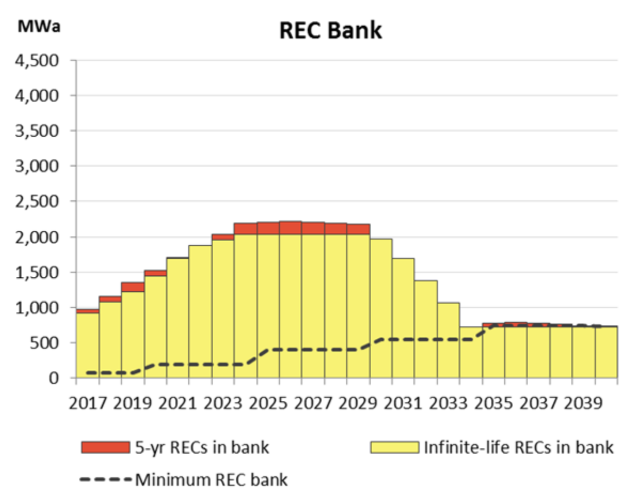




Portfolio Name	Supp_2018_150
COD	2018
Addition Size (MWa)	150
Minimum REC Bank Assumption	2016 IRP Assumption
Load Assumption	December 2016 Forecast

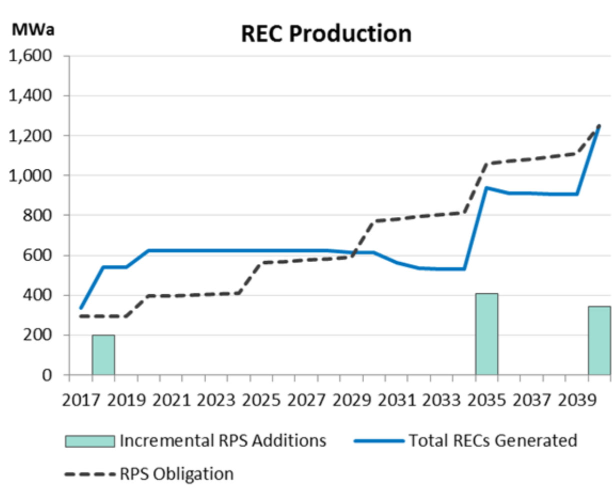
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	76
2018	150	488	295	89	1,073	76
2019	150	488	295	132	1,223	76
2020	150	572	396	75	1,452	194
2021	150	572	399	16	1,689	194
2025	150	572	563	170	2,041	406
2030	150	564	774	0	1,963	549
2035	776	1,106	1,057	49	729	746
2040	948	1,251	1,251	4	727	730

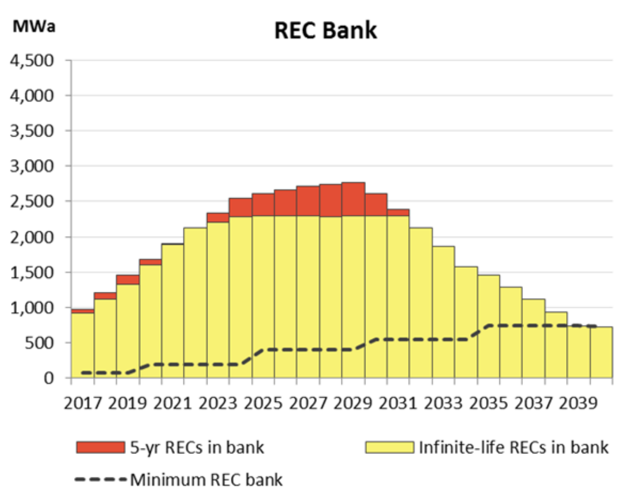




Portfolio Name	Supp_2018_200
COD	2018
Addition Size (MWa)	200
Minimum REC Bank Assumption	2016 IRP Assumption
Load Assumption	December 2016 Forecast

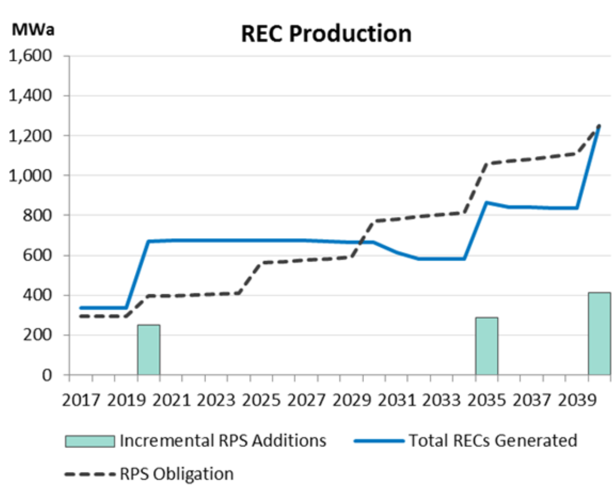
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	76
2018	200	538	295	89	1,123	76
2019	200	538	295	132	1,323	76
2020	200	622	396	75	1,602	194
2021	200	622	399	16	1,889	194
2025	200	622	563	320	2,291	406
2030	200	614	774	323	2,291	549
2035	606	936	1,057	0	1,458	746
2040	948	1,251	1,251	0	730	730

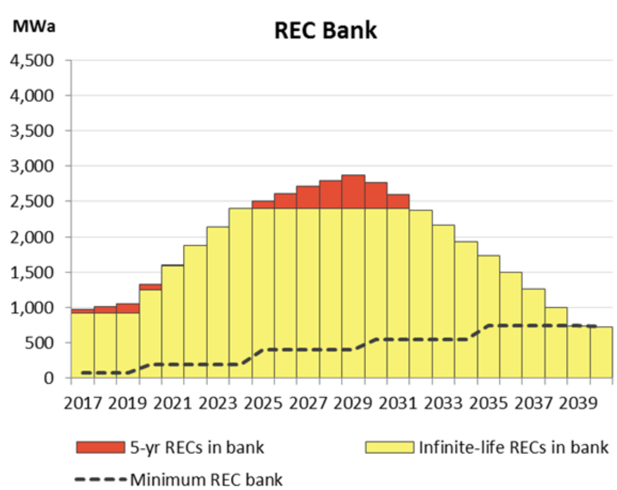




Portfolio Name	Supp_2020_250
COD	2020
Addition Size (MWa)	250
Minimum REC Bank Assumption	2016 IRP Assumption
Load Assumption	December 2016 Forecast

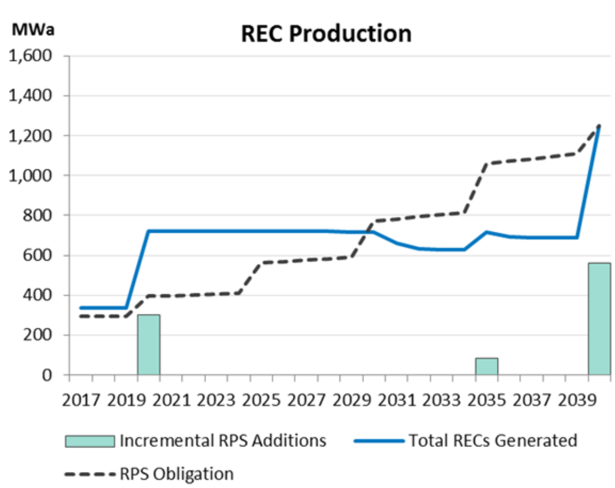
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	76
2018	0	338	295	89	923	76
2019	0	338	295	132	923	76
2020	250	672	396	75	1,253	194
2021	250	672	399	16	1,589	194
2025	250	672	563	110	2,402	406
2030	250	664	774	363	2,402	549
2035	536	866	1,057	0	1,739	746
2040	948	1,251	1,251	0	731	730

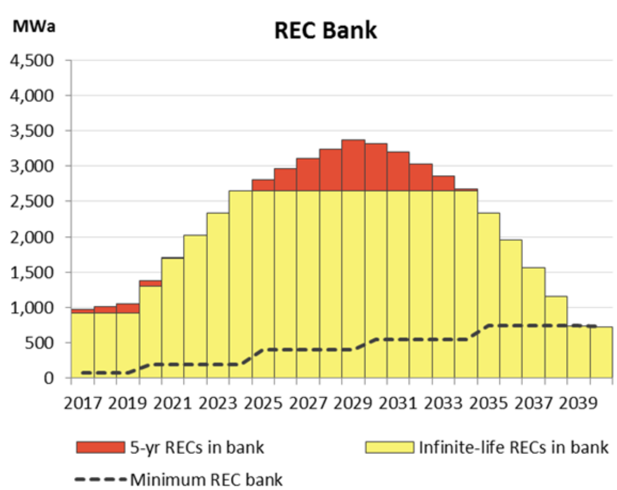




Portfolio Name	Supp_2020_300
COD	2020
Addition Size (MWa)	300
Minimum REC Bank Assumption	2016 IRP Assumption
Load Assumption	December 2016 Forecast

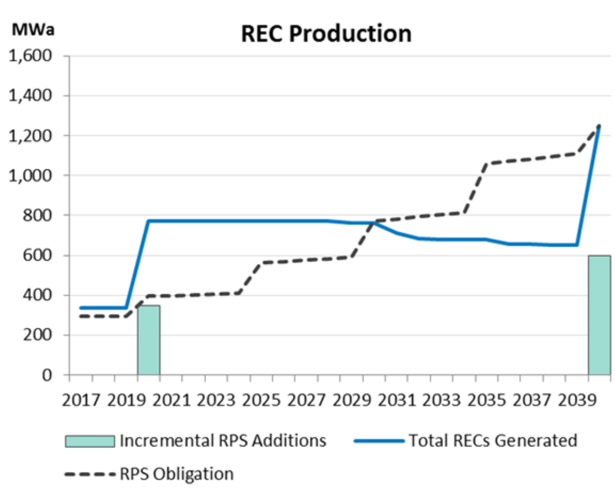
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	76
2018	0	338	295	89	923	76
2019	0	338	295	132	923	76
2020	300	722	396	75	1,303	194
2021	300	722	399	16	1,689	194
2025	300	722	563	160	2,652	406
2030	300	714	774	663	2,652	549
2035	386	716	1,057	0	2,339	746
2040	948	1,251	1,251	0	731	730

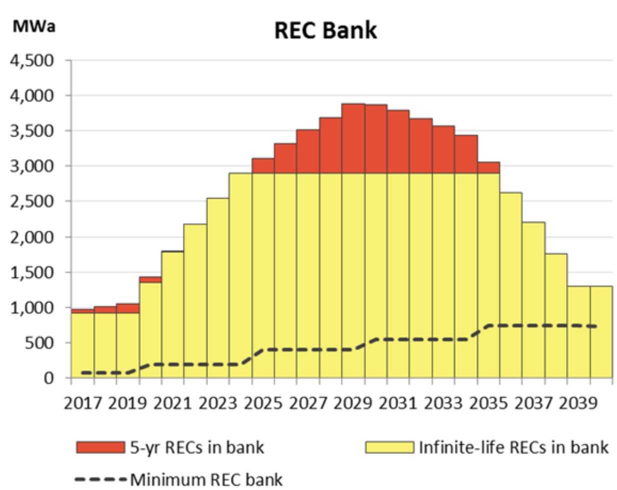




Portfolio Name	Supp_2020_350
COD	2020
Addition Size (MWa)	350
Minimum REC Bank Assumption	2016 IRP Assumption
Load Assumption	December 2016 Forecast

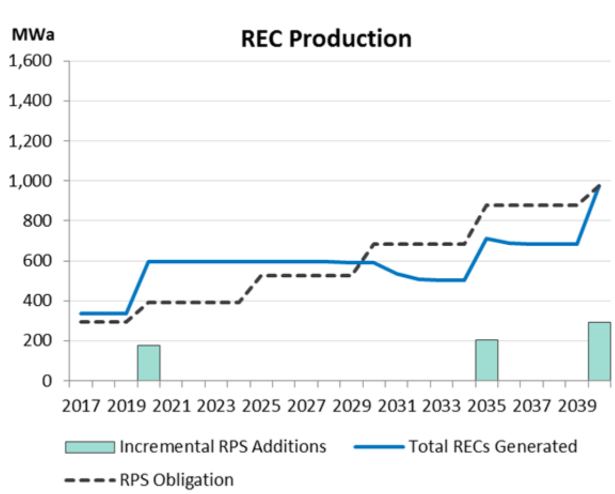
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	76
2018	0	338	295	89	923	76
2019	0	338	295	132	923	76
2020	350	772	396	75	1,353	194
2021	350	772	399	16	1,789	194
2025	350	772	563	210	2,902	406
2030	350	764	774	963	2,902	549
2035	350	680	1,057	151	2,902	746
2040	948	1,251	1,251	0	1,300	730

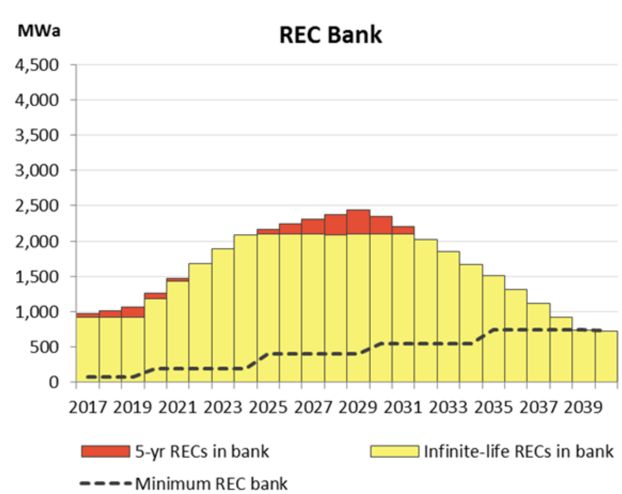




Portfolio Name	Supp_2020_175_LGZ
COD	2020
Addition Size (MWa)	175
Minimum REC Bank Assumption	2016 IRP Assumption
Load Assumption	Zero Load Growth

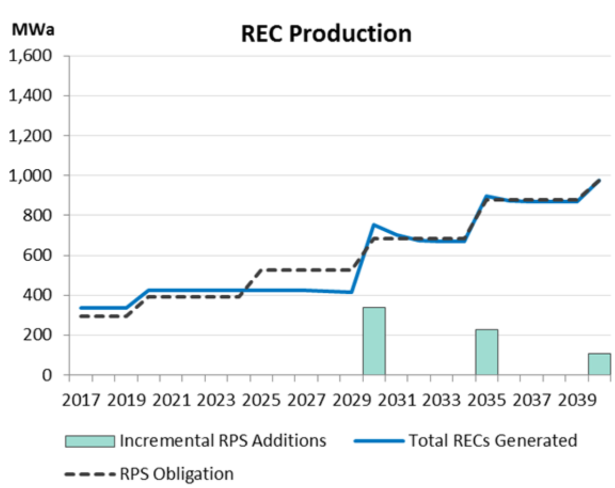
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	76
2018	0	338	293	91	923	76
2019	0	338	293	137	923	76
2020	175	597	390	86	1,178	194
2021	175	597	390	36	1,439	194
2025	175	597	527	71	2,097	406
2030	175	589	683	251	2,097	549
2035	381	711	878	0	1,508	746
2040	673	975	975	0	732	730

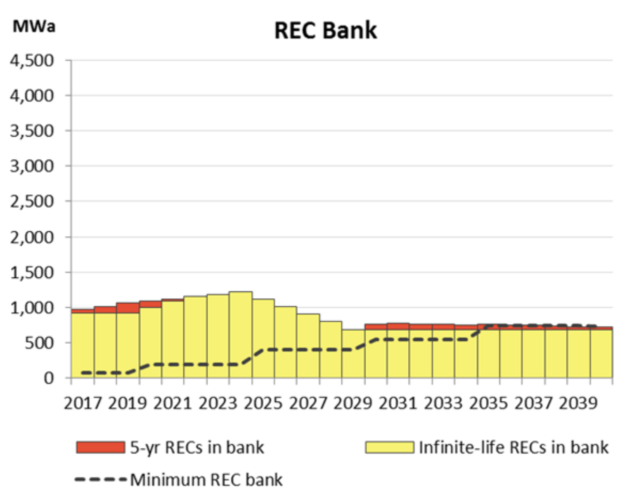




Portfolio Name	**Supp_Delay_LGZ**
COD	Delay
Addition Size (MWa)	
Minimum REC Bank Assumption	2016 IRP Assumption
Load Assumption	Zero Load Growth

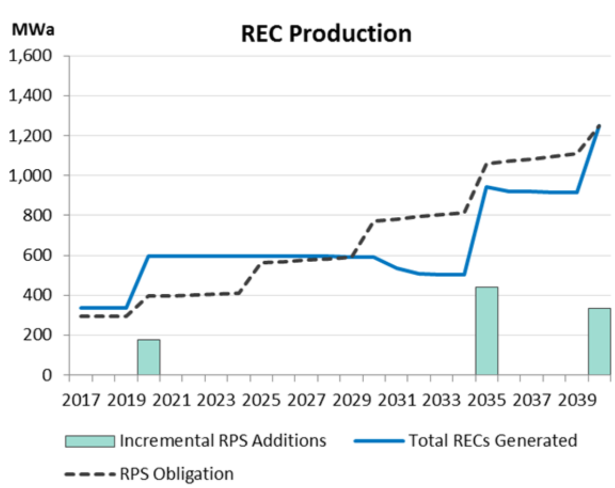
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	76
2018	0	338	293	91	923	76
2019	0	338	293	137	923	76
2020	0	422	390	86	1,003	194
2021	0	422	390	36	1,088	194
2025	0	422	527	0	1,117	406
2030	340	754	683	71	691	549
2035	566	896	878	74	691	746
2040	673	975	975	41	689	730

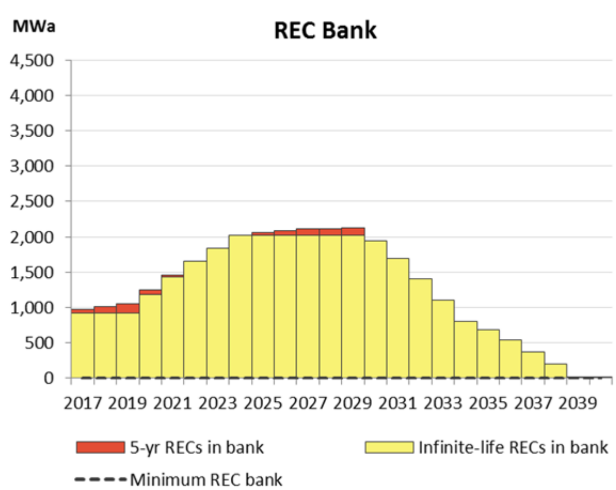




Portfolio Name	Supp_2020_175_RBZ
COD	2020
Addition Size (MWa)	175
Minimum REC Bank Assumption	Zero
Load Assumption	December 2016 Forecast

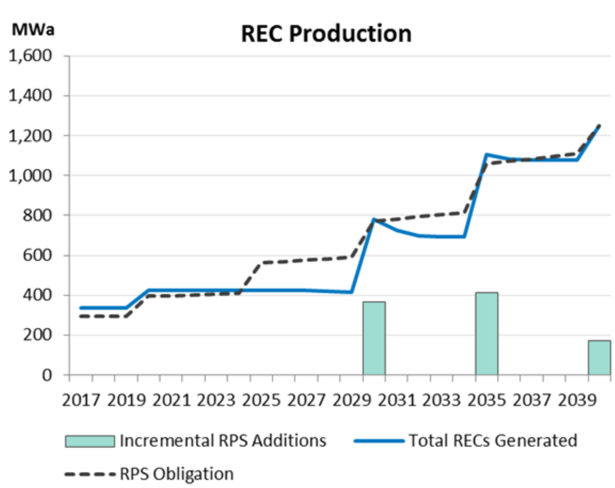
	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	0
2018	0	338	295	89	923	0
2019	0	338	295	132	923	0
2020	175	597	396	75	1,178	0
2021	175	597	399	16	1,439	0
2025	175	597	563	35	2,026	0
2030	175	589	774	0	1,939	0
2035	615	945	1,057	0	692	0
2040	948	1,251	1,251	0	1	0

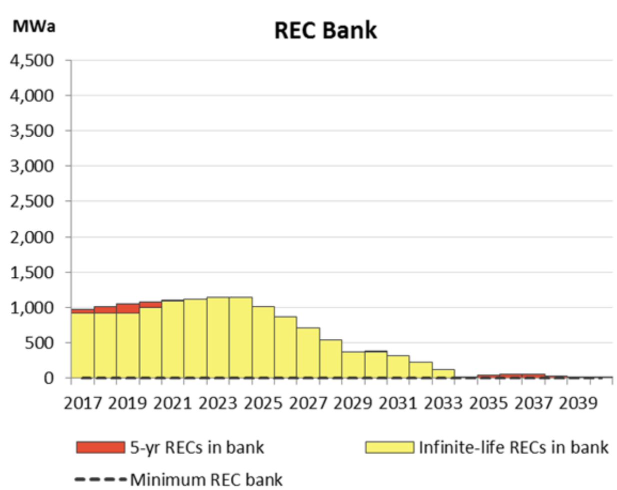




Portfolio Name	Supp_Delay_RBZ
COD	Delay
Addition Size (MWa)	
Minimum REC Bank Assumption	Zero
Load Assumption	December 2016 Forecast

	Cumulative RPS Additions (MWa)	Total RECs Generated (MWa)	Total RECs Retired (MWa)	5-yr RECs in bank (MWa)	Infinite-life RECs in bank (MWa)	Minimum REC bank (MWa)
2017	0	338	293	46	923	0
2018	0	338	295	89	923	0
2019	0	338	295	132	923	0
2020	0	422	396	75	1,003	0
2021	0	422	399	16	1,088	0
2025	0	422	563	0	1,010	0
2030	365	779	774	5	372	0
2035	775	1,106	1,057	48	1	0
2040	948	1,251	1,251	1	1	0





B.2. Relative NPVRR impacts across futures

In Section 3.1 of PGE's Reply Comments, the Company describes the NPVRR impacts of early RPS action under Reference Case assumptions. Figure 1 below shows the NPVRR impact of early action for the highest PTC eligibility scenarios associated with each COD and for the Delay Portfolio across all futures, including the low gas price futures described in Reply Comments Section 6.2.1. Within each future, the NPVRR is shown relative to the lowest cost portfolio.

Figure 1. Relative NPVRR of Early RPS Action and Delay portfolios based on the 2016 IRP Minimum REC bank.

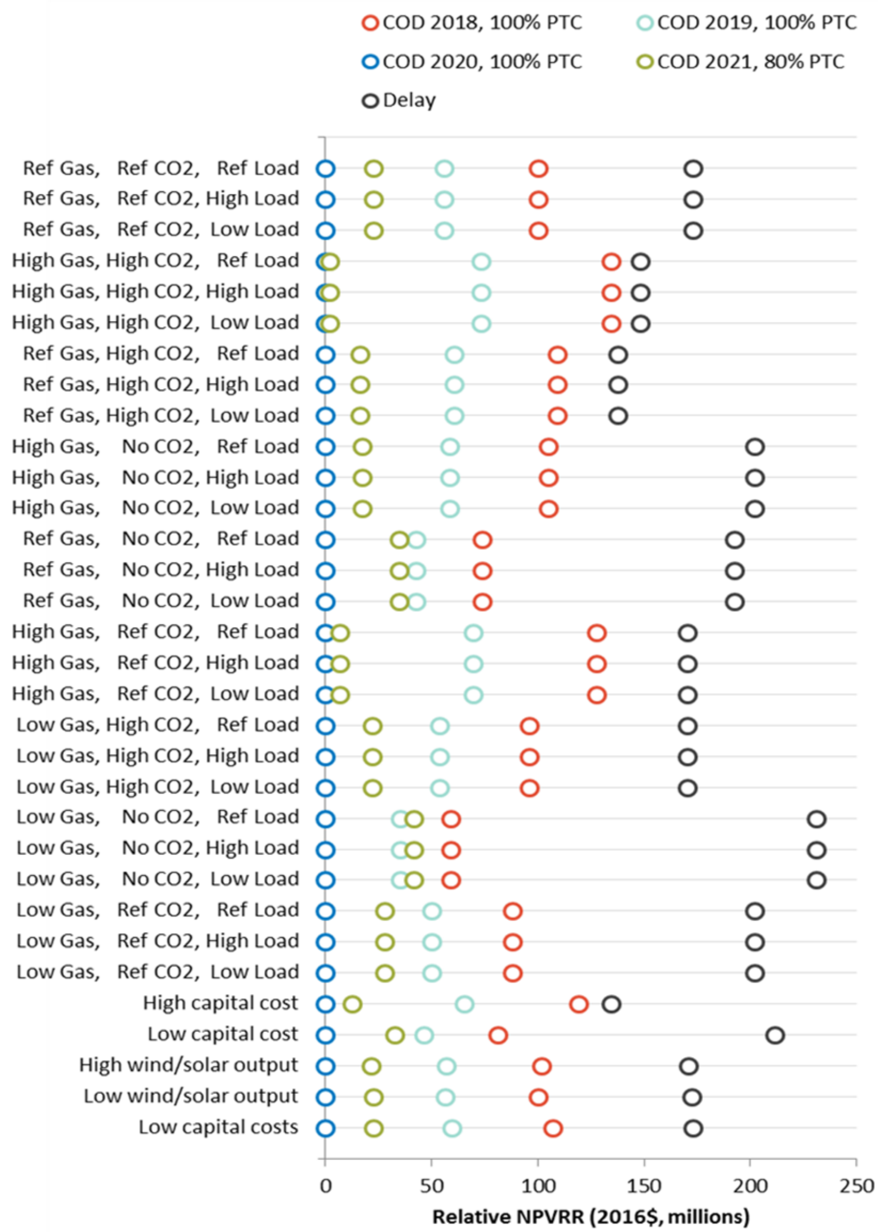
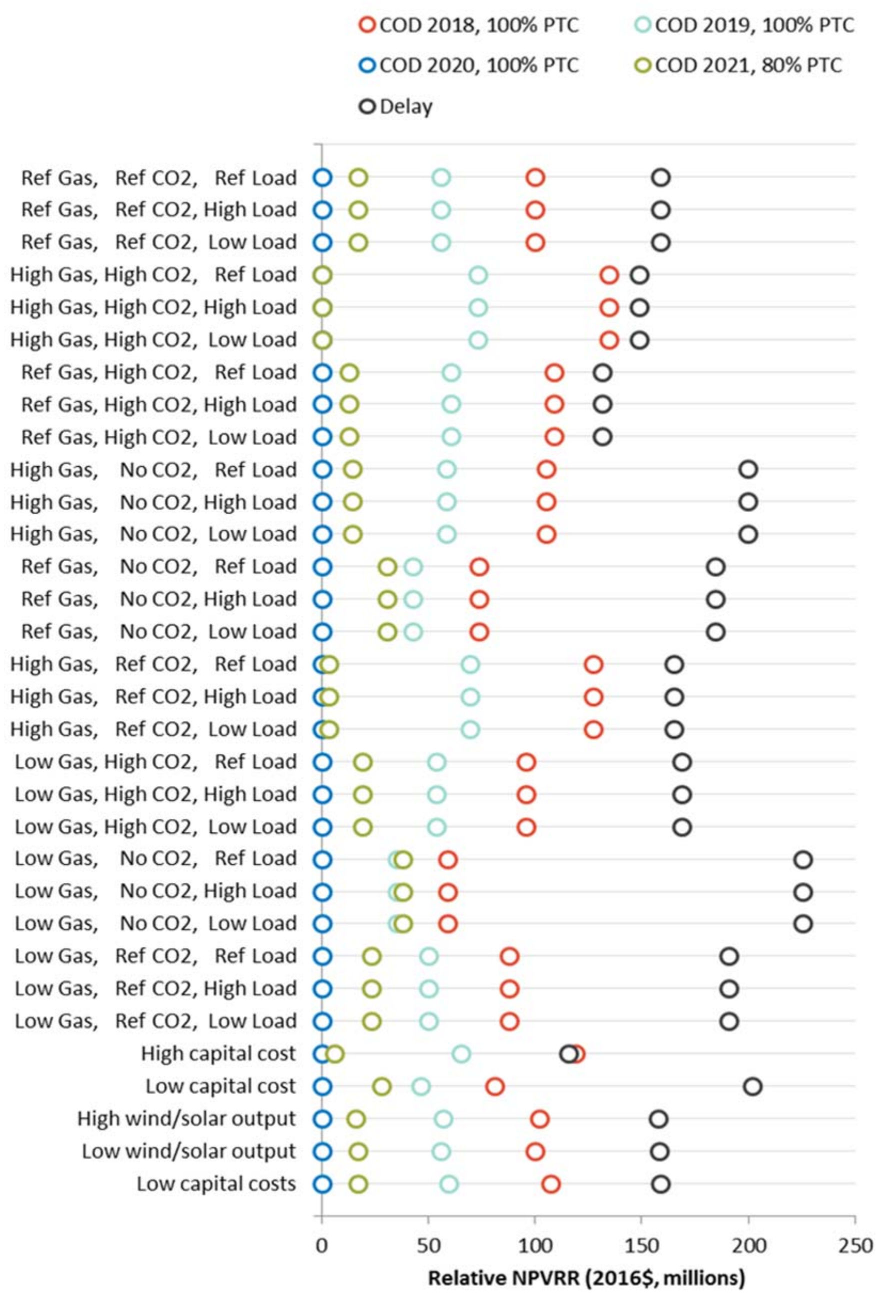


Figure 2 presents the same information for the corresponding portfolios under the Minimum REC Bank Sensitivity.

Figure 2. Relative NPVRR of Early RPS Action and Delay portfolios based on the Minimum REC Bank Sensitivity.



With the 2016 IRP Minimum REC Bank assumption, the identified value of early RPS action ranges from $134 million to $231 million (175 MWa in 2020 with 100% PTC eligibility) across the futures. With the Minimum REC Bank Sensitivity, the identified value of early RPS action ranges from $116 million to $226 million (175 MWa in 2020 with 100% PTC eligibility) across the futures.

LC 66/OPUC
February 10, 2017
PGE's 1st Set of Data Requests

PGE Data Request 2

2. Please provide all documentation and work papers supporting the following statement on page 16 of Staff's Initial Comments: "In fact, for any existing PTC held in account, ratepayers may be obligated to pay higher rates as a result of the Company holding them, rather than realize the savings they are expected to represent."

Response to PGE Data Request 2

2. Other than what is stated below, Staff does not have documents or work papers responsive to the data request.

   In UE 294, PGE forecasted that of the 49,150,287 PTCs to be generated, only 31,516,720 would be used in tax year 2016.[1] Furthermore, the Company forecasted that the year-end balance of PTCs would total 60,060,860.[2]

   In UM 1773, Industrial Customers of Northwest Utilities (ICNU) performed an analysis that demonstrates PGE's likely need to continue carrying forward PTCs as deferred tax assets if it were to acquire a 2018 renewable resource of approximately 175 MWa. ICNU's analysis shows that PGE's customers will incur approximately 230 million in costs due due to the revenue requirement of PTCs in ratebase.[3]

   On January 19, 2017, Staff and other participants held a call with PGE regarding the treatment and status of the Company's PTCs. On the call, PGE staff indicated that approximately 42,000,000 PTCs were included in rate base as a deferred tax asset, resulting in the Company earning a rate of return on these credits. PGE also indicated it has no assurances that it can utilize all PTCs in future years due to uncertainty of the Company's tax position in those future years.

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[1] PGE's 2016 General Rate Case, "2016 Schedule Ms" spreadsheet, "Tax Credits – Federal BLF" tab, Docket No. UE 294, February 12, 2015.
[2] Ibid.
[3] Supplemental Comments of ICNU, Affidavit of Bradley G. Mullins, Attachment B, at page 1, Docket No. UM 1773, June 28, 2016.

PGE PTC Carryforward Analysis

This attachment includes the several variations on the PTC carryforward analysis described in PGE Reply Comments Section 3.5. Specifically, the following analyses are included:

Corrections and updates to ICNU PTC analysis – with and without COD 2020 515 MW wind addition with 100% PTC.

PGE PTC analysis (CONFIDENTIAL) – with and without 515 MW wind additions under the following timing and PTC eligibility scenarios: COD 2020 (100%, 80%, and 60% PTC) and COD 2021 (80%, 60%, and 40% PTC).

NPVRR benefit of 515 MW wind resource with COD 2020 and 100% PTC eligibility

Deferred Tax Liability benefit of 515 MW wind resource with COD 2020

Table 1. Update to INCU analysis, including COD 2020 515 MW wind addition with 100% PTC (thousand $)

Year	Beg. Balance	Biglow 1	Biglow 2	Biglow 3	Tucannon	Oak Grove	515 MW	Total	Fed Tax offsetable with tax credits	Utilized	End Balance	Approx Rev Req.
2016	29,395	7,415	8,901	7,820	20,087	41	0	44,265	25,097	25,097	48,562	Not modeled
2017	48,562	7,262	9,643	8,530	19,933	49	0	45,418	31,517	31,517	62,463	6,459
2018	62,463	0	10,062	8,901	20,800	49	0	39,812	32,147	32,147	70,128	7,251
2019	70,128	0	7,916	9,272	21,667	49	0	38,904	32,790	32,790	76,242	7,883
2020	76,242	0	0	7,110	21,667	49	37,597	66,423	33,446	33,446	109,220	11,293
2021	109,220	0	0	0	22,533	53	39,101	61,688	34,115	34,115	136,792	14,144
2022	136,792	0	0	0	22,533	53	39,101	61,688	34,797	34,797	163,683	16,925
2023	163,683	0	0	0	23,400	53	40,605	64,058	35,493	35,493	192,248	19,878
2024	192,248	0	0	0	23,400	53	40,605	64,058	36,203	36,203	220,103	22,759
2025	220,103	0	0	0	0	58	42,108	42,166	36,927	36,927	225,342	23,300
2026	225,342	0	0	0	0	58	42,108	42,166	37,665	37,665	229,843	23,766
2027	229,843	0	0	0	0	58	43,612	43,670	38,419	38,419	235,094	24,309
2028	235,094	0	0	0	0	0	43,612	43,612	39,187	39,187	239,519	24,766
2029	239,519	0	0	0	0	0	43,612	43,612	39,971	39,971	243,161	25,143
2030	243,161	0	0	0	0	0	0	0	40,770	40,770	202,391	20,927
2031	202,391	0	0	0	0	0	0	0	41,586	41,586	160,805	16,627
2032	160,805	0	0	0	0	0	0	0	42,417	42,417	118,388	12,241
2033	118,388	0	0	0	0	0	0	0	43,266	43,266	75,122	7,768
2034	75,122	0	0	0	0	0	0	0	44,131	44,131	30,991	3,204
2035	30,991	0	0	0	0	0	0	0	45,014	30,991	0	0
2036	0	0	0	0	0	0	0	0	45,914	0	0	0
2037	0	0	0	0	0	0	0	0	46,832	0	0	0
2038	0	0	0	0	0	0	0	0	47,769	0	0	0
2039	0	0	0	0	0	0	0	0	48,724	0	0	0
2040	0	0	0	0	0	0	0	0	49,699	0	0	0
2041	0	0	0	0	0	0	0	0	50,693	0	0	0
											2016 Present Value Rev. Req. (2016$)	164,270
											Incremental PVRR from 515 MW Wind	127,401

Table 2. Update to INCU analysis, excluding 515 MW wind addition (thousand $)

Year	Beg. Balance	Biglow 1	Biglow 2	Biglow 3	Tucannon	Oak Grove	Total	Fed Tax offsetable with tax credits	Utilized	End Balance	Approx Rev Req.
2016	29,395	7,415	8,901	7,820	20,087	41	44,265	25,097	25,097	48,562	Not modeled
2017	48,562	7,262	9,643	8,530	19,933	49	45,418	31,517	31,517	62,463	6,459
2018	62,463	0	10,062	8,901	20,800	49	39,812	32,147	32,147	70,128	7,251
2019	70,128	0	7,916	9,272	21,667	49	38,904	32,790	32,790	76,242	7,883
2020	76,242	0	0	7,110	21,667	49	28,827	33,446	33,446	71,623	7,406
2021	71,623	0	0	0	22,533	53	22,587	34,115	34,115	60,095	6,214
2022	60,095	0	0	0	22,533	53	22,587	34,797	34,797	47,885	4,951
2023	47,885	0	0	0	23,400	53	23,453	35,493	35,493	35,845	3,706
2024	35,845	0	0	0	23,400	53	23,453	36,203	36,203	23,096	2,388
2025	23,096	0	0	0	0	58	58	36,927	23,153	0	0
2026	0	0	0	0	0	58	58	37,665	58	0	0
2027	0	0	0	0	0	58	58	38,419	58	0	0
2028	0	0	0	0	0	0	0	39,187	0	0	0
2029	0	0	0	0	0	0	0	39,971	0	0	0
2030	0	0	0	0	0	0	0	40,770	0	0	0
2031	0	0	0	0	0	0	0	41,586	0	0	0
2032	0	0	0	0	0	0	0	42,417	0	0	0
2033	0	0	0	0	0	0	0	43,266	0	0	0
2034	0	0	0	0	0	0	0	44,131	0	0	0
2035	0	0	0	0	0	0	0	45,014	0	0	0
2036	0	0	0	0	0	0	0	45,914	0	0	0
2037	0	0	0	0	0	0	0	46,832	0	0	0
2038	0	0	0	0	0	0	0	47,769	0	0	0
2039	0	0	0	0	0	0	0	48,724	0	0	0
2040	0	0	0	0	0	0	0	49,699	0	0	0
2041	0	0	0	0	0	0	0	50,693	0	0	0
								2016 Present Value Rev. Req. (2016$)			36,869

Table 3. PGE PTC analysis, [redacted]

[redacted]

Table 4. PGE PTC analysis, [redacted]

[redacted]

Table 5. PGE PTC analysis, [redacted]

Table 6. PGE PTC analysis, [redacted]

[redacted]

Table 7. PGE PTC analysis, [redacted]

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Table 8. PGE PTC analysis, [redacted]

[redacted]

Table 9. PGE PTC analysis, [redacted]

[redacted]

Table 10. NPVRR impact of generated PTCs for a 515 MW wind resource with COD 2020 and 100% PTC eligibility (thousand $)

Year	PTCs Generated	Revenue Requirement Impact
2017	0	0
2018	0	0
2019	0	0
2020	(37,597)	(62,661)
2021	(39,101)	(65,168)
2022	(39,101)	(65,168)
2023	(40,605)	(67,674)
2024	(40,605)	(67,674)
2025	(42,108)	(70,181)
2026	(42,108)	(70,181)
2027	(43,612)	(72,687)
2028	(43,612)	(72,687)
2029	(43,612)	(72,687)
	PVRR (2016$)	(414,411)

Table 11. NPVRR Impact of deferred tax liability (DTL) associated with 515 MW wind resource with COD 2020 (thousand $)

Year	Book Depreciation	Tax Depreciation	Difference	Incremental DTL	Cumulative DTL	Revenue Requirement Impact
2017	0	0	0	0	0	0
2018	0	0	0	0	0	0
2019	0	0	0	0	0	0
2020	32,407	174,997	(142,590)	(57,036)	(57,036)	(5,898)
2021	32,407	279,995	(247,588)	(99,035)	(156,071)	(16,138)
2022	32,407	167,997	(135,590)	(54,236)	(210,308)	(21,746)
2023	32,407	100,798	(68,391)	(27,357)	(237,664)	(24,574)
2024	32,407	100,798	(68,391)	(27,357)	(265,021)	(27,403)
2025	32,407	50,399	(17,992)	(7,197)	(272,218)	(28,147)
2026	32,407	0	32,407	12,963	(259,255)	(26,807)
2027	32,407	0	32,407	12,963	(246,292)	(25,467)
2028	32,407	0	32,407	12,963	(233,329)	(24,126)
2029	32,407	0	32,407	12,963	(220,367)	(22,786)
2030	32,407	0	32,407	12,963	(207,404)	(21,446)
2031	32,407	0	32,407	12,963	(194,441)	(20,105)
2032	32,407	0	32,407	12,963	(181,478)	(18,765)
2033	32,407	0	32,407	12,963	(168,516)	(17,425)
2034	32,407	0	32,407	12,963	(155,553)	(16,084)
2035	32,407	0	32,407	12,963	(142,590)	(14,744)
2036	32,407	0	32,407	12,963	(129,627)	(13,403)
2037	32,407	0	32,407	12,963	(116,665)	(12,063)
2038	32,407	0	32,407	12,963	(103,702)	(10,723)
2039	32,407	0	32,407	12,963	(90,739)	(9,382)
2040	32,407	0	32,407	12,963	(77,776)	(8,042)
2041	32,407	0	32,407	12,963	(64,814)	(6,702)
2042	32,407	0	32,407	12,963	(51,851)	(5,361)
2043	32,407	0	32,407	12,963	(38,888)	(4,021)
2044	32,407	0	32,407	12,963	(25,925)	(2,681)
2045	32,407	0	32,407	12,963	(12,963)	(1,340)
2046	32,407	0	32,407	12,963	(0)	(0)
				2016 Present Value Rev. Req. (2016$)		(190,730)

Memorandum

To: Alison Lucas, Portland General Electric (PGE)

From: Juan Pablo Carvallo and Peter Larsen, Lawrence Berkeley National Laboratory (LBNL)

Date: March 24, 2017

Subject: Response to questions about PGE's load forecast error

This memorandum is in response to your questions on how LBNL estimated load forecast errors for PGE as reported in the report *Load Forecasting in Electric Utility Integrated Resource Planning*[1] hereinafter the LBNL report. PGE was asked by the Oregon Public Utility Commission (OPUC) to explain—in-depth—their load forecasting methods and assumptions as part of their 2016 IRP filing. The OPUC stated that:

> "PGE had the highest forecast error among all utilities studied (table 3) [in the LBNL report] and PGE's projections of its load growth rates increased over time despite the fact that PGE's actual load growth rates were declining (table 13)… The poor historical performance of PGE's load forecast, relative to the other electric load-serving entities studied by LBNL, further increases Staff's concerns."[2]

Below, we focus on your questions about the values reported in tables 3-5 in the LBNL report. Before proceeding, we wish to note that the information on PGE that we used in our analysis is contained in a database within the LBNL Resource Planning Portal (http://resourceplanning.lbl.gov). This database is built from information in dozens of resource plans submitted to regulators by a large number of utilities across the Western United States, organized into a standard format. As it is presented in these planning documents, this information is often voluminous, generally complicated, and in some cases contradictory. Thus, the development of the database and its formatting required considerable amount of interpretation and processing. For this reason, we are always willing to correct the record as needed as more (or

[1] Carvallo, J.P., P. Larsen, A. Sanstad, and C. Goldman 2016. Load forecasting in electric utility integrated resource planning. LBNL Report 1006395, October.

[2] Oregon Public Utility Commission. 2017. Staff's initial comments on the Portland General Electric 2016 Integrated Resource Plan. LC 66, pp. 1-41.

clarifying) information comes forward, and we appreciate your bringing your questions and concerns to our attention.

Question #1: Did LBNL "net out" energy efficiency from PGE's base forecast? If so, this would mean that LBNL double-counted the energy efficiency in the load forecast thus introducing an artificially high forecast error.

As part of its standardized formatting of utility information, LBNL netted out energy efficiency (EE) from the base forecast for all the LSEs represented in our database that did not explicitly net out EE from their load forecasts as reported in their IRPs. For PGE, we based our decision on several pieces of evidence found throughout the 2007 IRP. First, the 2007 IRP indicated that the: "demand forecast was developed from historical data, i.e. net of EE savings. **It does not, however, include potential savings from future incremental EE programs above past implementation rates**" (emphasis added, p. 39). Second, we based our decision on the narrative in Chapter 4 suggesting that EE is treated as a resource equivalent to supply-side options. That typically means incremental EE would not be netted out the base case load forecast but rather accounted for and modeled in a manner equivalent to other resource options (subsection 4.2 of the IRP). Finally, it not common practice for LSEs to net out both historical and expected EE from base load forecasts. For these reasons, we removed expected EE from the base load forecast.

However, there is contradictory information presented later in the plan (p.57) suggesting that PGE effectively ended up netting out ~85 MWa of expected EE from the original forecast. Further, you confirmed in a subsequent email (February 6, 2017) that both historical and expected EE were effectively already netted out of the forecast. Based on this new information, we re-estimated PGE's forecast energy Annual Average Growth Rate (AAGR) and associated error in Table 4 (Note: Table 5—describing peak demand AAGR—remains unchanged), and compared it to the original estimates as published in our report. The updated results are presented below in Tables 1 and 2, along with our corresponding estimates for the other LSEs. These results show a decrease in PGE forecast growth rate from 2.6% to 1.8%. The revised estimates position PGE in the middle-range relative to the other LSEs discussed in the report.

Table 1. Original energy AAGR calculation (Table 4 in the LBNL report)

	Energy AAGR		
LSE	**Forecast**	**Observed**	**Difference**
PNM	2.2%	-1.4%	3.6%
PGE	***2.6%***	***0.2%***	***2.4%***
SierraPacific	1.4%	-0.9%	2.3%
NVPower	2.3%	0.1%	2.3%
COPSC	1.8%	-0.4%	2.2%
PugetSound	1.7%	-0.2%	1.9%
Avista	1.7%	-0.1%	1.8%
Idaho	1.4%	-0.1%	1.5%
Seattle	1.1%	0.2%	1.0%
PacifiCorp	1.9%	1.3%	0.6%
LADWP	0.6%	0.0%	0.6%
NW	0.6%	1.2%	-0.6%

Table 2. Revised energy AAGR calculation (emphasis added for PGE)

	Energy AAGR		
LSE	**Forecast**	**Observed**	**Difference**
PNM	2.2%	-1.4%	3.6%
SierraPacific	1.4%	-0.9%	2.3%
NVPower	2.3%	0.1%	2.3%
COPSC	1.8%	-0.4%	2.2%
PugetSound	1.7%	-0.2%	1.9%
Avista	1.7%	-0.1%	1.8%
PGE	***1.8%***	***0.2%***	***1.6%***
Idaho	1.4%	-0.1%	1.5%
Seattle	1.1%	0.2%	1.0%
PacifiCorp	1.9%	1.3%	0.6%
LADWP	0.6%	0.0%	0.6%
NW	0.6%	1.2%	-0.6%

Question #2: How did LBNL calculate a cumulative forecast error of 19% for PGE (see Table 3 in the LBNL report)?

In our standardized analysis protocol, the cumulative error in a given LSE's forecast is estimated by dividing the cumulative *difference* between the actual values and forecast values by the *actual* values to create a normalized metric. In the case of PGE, we did not remove EE from the base load forecast. **Therefore, both the PGE and LBNL load forecasts are identical.** LBNL used data from form EIA-861 that was downloaded via the Ventyx Velocity Suite database[3], which was included under separate cover. As you can see, the numbers provided by you in your February 7, 2017, email to LBNL as "actuals" for energy in the utility's calculations are higher than the sum of retail sales and losses as reported in EIA-861 (see Table 3). One way to increase LBNL's forecast to more closely match PGE's forecast would involve also including a portion of PGE's declared wholesale sales[4]. However, almost all of PGE's wholesale sales are short-term, firm contracts. We find no evidence in the PGE IRP that these types of sales contracts are included in PGE's load forecast. We were interested in learning more from PGE about what explains this discrepancy and how to correctly account for it in future studies.

Subsequently, you provided an explanation for this difference that we believe is more adequate. The load figures we had considered in our calculations did not include sales to non-cost-of-service (delivery only) energy customers, which PGE does include in their IRP forecast. You also commented that the energy losses that are reported in form EIA-861 include a portion that accrue to wholesale sales, which are not part of their net system load forecast (and hence should not be considered for "actuals"). We follow these criteria and produce a revised estimate for actual load that includes both delivery and bundled sales (see Table 3, rightmost column). Our revised "actuals" are closer to the values provided by PGE. Using these revised values, we produce a revised version of the original Table 3 in our report in which PGE's proportional forecast error is 10% instead of 19% (see Table 4, below, for the revised table)

Thank you again for your interest in our work and for providing more detailed information into how PGE estimates load forecasts—and any associated errors. Please do not hesitate to follow up with us if we can provide further clarification or additional information.

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[3] Please note that we are generally restricted from broadly distributing this data. In this case, however, we are making an exception, because this information is made publicly-available elsewhere. Regardless, please do not distribute this information outside of PGE and the Oregon PUC.

[4] Most LSEs that we analyzed included RQ (Requirements Service) wholesale sale contracts as part of their load forecast. See page eight of the LBNL report.

Table 3. Forecast and actual load (provided by PGE in February 7, 2017 email to LBNL) and the loads used in LBNL report based on EIA-861 data.

Year	PGE forecast (GWh)	PGE actual load (GWh)	LBNL actual load from EIA-861 (GWh)	LBNL revised actual load from EIA-861 (GWh)
2007	21,287	20,856	18,595	20,759
2008	21,667	21,201	18,696	21,114
2009	21,900	20,475	18,545	20,463
2010	22,294	19,917	18,819	19,869
2011	22,695	20,445	19,432	20,421
2012	23,039	20,307	18,960	20,206
2013	23,453	20,549	19,372	20,987
2014	24,090	20,404	18,891	20,554

Table 4. Revised version of Table 3 from LBNL report showing proportional forecast error calculation (emphasis added for PGE)

LSE	Sum of errors (1) [TWh]	Sum of actual load (2) [TWh]	Proportional Error (1)/(2)
Avista	14.73	85.36	17%
NVPower	26	199.01	13%
SierraPacific	10.57	89.37	12%
PGE	***16.1***	***164.37***	***10%***
Idaho	13.47	138.43	10%
PNM	5.64	85.17	7%
COPSC	21.41	365.05	6%
LADWP	13.04	236.45	6%
PacifiCorp	33.43	580.63	6%
Seattle	5.15	100.48	5%
PugetSound	2.09	206.15	1%
NW	-1.29	68.5	-2%

LC 66 – PGE’s REPLY COMMENTS – ATTACHMENT F

Individual Customer Forecast Sensitivity

(CONFIDENTIAL)

Provided to Commission Staff under separate cover
under the General Protective Order No. 16-408

From: Spencer Moersfelder
To: Jimmy Lindsay
Cc: Adam Shick
Subject: RE: PGE Question re 10% Benefit
Date: Thursday, March 23, 2017 11:32:47 AM

Please take care when opening links, attachments or responding to this email as it originated outside of PGE.

Hello Jimmy:

Yes we do use both the risk reduction value and the 10% conservation adder in our Avoided Costs. We do not currently apply the 10% conservation adder to the risk reduction value.

There are four components that Energy Trust uses to build up Avoided Costs. These components are represented in the table below. The table also indicates which components receive the 10% adder.

Avoided Cost Components	Apply 10% Conservation Adder (Y/N)?
Forward Market Price	Y
Avoided T&D	Y
Risk Reduction Value	N
Capacity Resource Deferral	N

Please let me know if this makes sense.

Best regards,
Spencer

Spencer Moersfelder
Planning Manager

503.445.7635 DIRECT
503.546.6862 FAX
energytrust.org

From: Jimmy Lindsay [mailto:Jimmy.Lindsay@pgn.com]
Sent: Thursday, March 23, 2017 10:07 AM
To: Adam Shick <adam.shick@energytrust.org>; Spencer Moersfelder <Spencer.Moersfelder@energytrust.org>
Subject: PGE Question re 10% Benefit

Dear Adam and Spencer,

We're looking to clarify in our IRP how ETO uses the 10% adder when considering EE cost effectiveness. From our previous conversation, I understand that ETO applies the 10% benefit in your EE cost effectiveness calculation in addition to the scenario risk benefit (despite the fact that PGE's cost effectiveness workpapers suggest inclusion of the maximum of the 10% benefit and the scenario risk benefit). I also understand that applying both the 10% adder and the scenario risk benefit is consistent with established ETO practice. I was hoping you could confirm this by email as we seek to clarify the application for our IRP audience. Thank you for your help.

Best,

Jimmy Lindsay

Jimmy Lindsay I Resource Strategy I o: 503-464-8311 I jimmy.lindsay@pgn.com
Portland General Electric I 121 SW Salmon Street, 3WTC0306, Portland, OR 97204

January 17, 2017

TO: Kay Barnes
Oregon Public Utility Commission

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 66
PGE Response to OPUC Data Request No. 074
Dated January 3, 2017

Request:

On page 172, table 6-6, PGE shows 2021 Demand Response (DR) achievable results in megawatts. This table shows much greater achievable potential than the 77 MW of DR currently contained in most portfolios. For example: the residential, air-conditioning direct load control measure is shown to be cost-effective (table 6-7) and to be able to provide over 106 MW of achievable potential. Please explain in detail the constraints PGE believes it faces in achieving more than 77 MW of DR by 2021.

Response:

As described in its 2016 IRP, PGE expects steady DR program growth but at a pace more gradual than utility programs in mature markets. PGE’s expectation for more gradual growth is based on several factors. These include low customer and partner awareness in the region, which slows the adoption of new measures. There are also few examples of winter DR programs. As noted in its IRP, PGE is currently piloting the first winter bring-your-own –thermostat program with Nest. Additionally, PGE has received some stakeholder opposition towards opt-out pricing programs that were identified in PGE’s DR potential study. Notably, the opt-out pricing programs are a key difference between the Reference and High case for DR in PGE’s 2016 IRP.

PGE describes how it derived to a 77 MW of DR by 2021 in sections 6.3.1.4 of the 2016 IRP. PGE’s estimate represents a prudent assessment of the portion of the maximum achievable peak potential that can be procured by 2021. More precisely PGE described its procurement assessment as follows:

- Table 6-6 is the maximum potential of DR in PGE's territory;
- Table 6-8 selects for IRP purposes those DR programs that are likely to be cost-effective and acquired consistent with lessons learned from previous pilots;
- Table 6-9 describes how the IRP selected DR was further reduced to account for the pilot period and interactions between programs;
- Table 6-10 explains that PGE adjusted the participation rate from the theoretical 100% of table 6-6 to the expected one. It also describes how the default five years of maturation rate on table 6-6 was increased based on the results of pilots conducted so far;
- Table 6-11 shows the targeted demand reduction by season and scenario. In addition to the revisions listed above, PGE also accounted for potential program implementation delays and reduced population targeted.

All IRP portfolios use the Reference scenario DR. Appendix O of the IRP shows for the projected amount and timing of DR acquisitions from 2017 to 2035 by portfolio based on its expected annual capacity.

Table 1. NPVRR (million 2016$) under 34-year horizon (2016 IRP assumption)

Future	Efficient Capacity 2021	RPS Wind 2018	Wind 2018 Long	Wind 2018	Wind 2018 + Solar PV 2021	Geothermal 2021	Wind 2018 + Solar PV 2018	Boardman Biomass 2021	Efficient Capacity 2021 + High EE	Wind 2018 + High EE	RPS Wind 2020	RPS Wind 2021	RPS Wind 2025	Efficient Capacity 2021 - Min Bank
Low Gas, No CO2, Low Load	$25,186	$25,227	$25,802	$25,299	$25,348	$25,412	$25,435	$26,922	$27,684	$27,768	$25,428	$25,377	$25,447	$25,399
Low Gas, No CO2, Ref Load	$26,404	$26,445	$27,021	$26,517	$26,566	$26,630	$26,653	$28,140	$28,902	$28,987	$26,646	$26,595	$26,665	$26,617
Low Gas, No CO2, High Load	$27,630	$27,670	$28,246	$27,742	$27,792	$27,856	$27,879	$29,366	$30,127	$30,212	$27,872	$27,820	$27,891	$27,842
Low Gas, Ref CO2, Low Load	$27,646	$27,880	$28,283	$27,990	$28,038	$28,106	$28,125	$29,537	$29,903	$30,213	$28,035	$27,994	$28,050	$27,808
Low Gas, Ref CO2, Ref Load	$29,739	$29,972	$30,376	$30,082	$30,130	$30,199	$30,217	$31,630	$31,995	$32,305	$30,127	$30,086	$30,142	$29,900
Low Gas, Ref CO2, High Load	$31,845	$32,078	$32,482	$32,188	$32,237	$32,305	$32,324	$33,736	$34,102	$34,411	$32,234	$32,192	$32,249	$32,007
Low Gas, High CO2, Low Load	$28,411	$28,734	$29,036	$28,826	$28,890	$28,940	$28,977	$30,366	$30,587	$30,974	$28,857	$28,830	$28,868	$28,534
Low Gas, High CO2, Ref Load	$30,869	$31,192	$31,493	$31,284	$31,347	$31,398	$31,434	$32,824	$33,045	$33,432	$31,314	$31,288	$31,325	$30,992
Low Gas, High CO2, High Load	$33,343	$33,666	$33,968	$33,758	$33,822	$33,872	$33,909	$35,299	$35,519	$35,906	$33,789	$33,762	$33,800	$33,466
Ref Gas, No CO2, Low Load	$26,264	$26,345	$26,882	$26,463	$26,521	$26,580	$26,608	$28,033	$28,639	$28,801	$26,509	$26,480	$26,523	$26,432
Ref Gas, No CO2, Ref Load	$27,975	$28,056	$28,594	$28,175	$28,233	$28,292	$28,320	$29,745	$30,350	$30,512	$28,220	$28,192	$28,234	$28,144
Ref Gas, No CO2, High Load	$29,699	$29,780	$30,318	$29,899	$29,957	$30,016	$30,044	$31,469	$32,074	$32,236	$29,944	$29,916	$29,958	$29,868
Ref Gas, Ref CO2, Low Load	$28,819	$29,005	$29,376	$29,152	$29,206	$29,269	$29,292	$30,674	$30,976	$31,268	$29,130	$29,107	$29,141	$28,946
Ref Gas, Ref CO2, Ref Load	**$31,319**	**$31,504**	**$31,875**	**$31,652**	**$31,705**	**$31,769**	**$31,792**	**$33,173**	**$33,476**	**$33,768**	**$31,630**	**$31,607**	**$31,641**	**$31,446**
Ref Gas, Ref CO2, High Load	$33,837	$34,022	$34,393	$34,169	$34,223	$34,287	$34,310	$35,691	$35,994	$36,286	$34,148	$34,125	$34,158	$33,964
Ref Gas, High CO2, Low Load	$29,591	$29,892	$30,168	$30,030	$30,100	$30,143	$30,186	$31,534	$31,661	$32,063	$29,982	$29,976	$29,989	$29,677
Ref Gas, High CO2, Ref Load	$32,466	$32,767	$33,043	$32,905	$32,975	$33,018	$33,061	$34,409	$34,536	$34,938	$32,857	$32,851	$32,864	$32,552
Ref Gas, High CO2, High Load	$35,362	$35,663	$35,939	$35,801	$35,871	$35,914	$35,957	$37,305	$37,432	$37,834	$35,753	$35,747	$35,760	$35,448
High Gas, No CO2, Low Load	$29,242	$29,388	$29,544	$29,442	$29,530	$29,567	$29,616	$30,875	$31,325	$31,507	$29,511	$29,467	$29,524	$29,371
High Gas, No CO2, Ref Load	$31,991	$32,137	$32,293	$32,191	$32,278	$32,315	$32,365	$33,624	$34,073	$34,256	$32,260	$32,216	$32,273	$32,120
High Gas, No CO2, High Load	$34,758	$34,904	$35,060	$34,958	$35,046	$35,083	$35,132	$36,391	$36,841	$37,023	$35,027	$34,983	$35,040	$34,888
High Gas, Ref CO2, Low Load	$31,838	$31,930	$31,959	$32,017	$32,096	$32,138	$32,182	$33,427	$33,751	$33,906	$32,011	$31,982	$32,019	$31,921
High Gas, Ref CO2, Ref Load	$35,202	$35,294	$35,323	$35,381	$35,460	$35,502	$35,546	$36,791	$37,115	$37,270	$35,375	$35,346	$35,383	$35,285
High Gas, Ref CO2, High Load	$38,590	$38,682	$38,710	$38,768	$38,847	$38,890	$38,934	$40,178	$40,502	$40,658	$38,762	$38,733	$38,771	$38,672
High Gas, High CO2, Low Load	$32,653	$32,817	$32,776	$32,899	$32,993	$33,016	$33,080	$34,303	$34,485	$34,711	$32,874	$32,855	$32,880	$32,707
High Gas, High CO2, Ref Load	$36,381	$36,546	$36,505	$36,628	$36,721	$36,744	$36,808	$38,032	$38,214	$38,440	$36,603	$36,584	$36,609	$36,436
High Gas, High CO2, High Load	$40,137	$40,301	$40,260	$40,383	$40,477	$40,500	$40,564	$41,787	$41,969	$42,195	$40,358	$40,339	$40,364	$40,192
Low Hydro Availability	$31,868	$32,199	$32,506	$32,343	$32,397	$32,465	$32,485	$33,881	$33,990	$34,426	$32,317	$32,294	$32,328	$31,987
Low VER Capacity Factor	$31,328	$31,515	$31,886	$31,663	$31,746	$31,781	$31,835	$33,187	$33,484	$33,779	$31,640	$31,617	$31,651	$31,454
High VER Capacity Factor	$30,846	$31,028	$31,295	$31,151	$31,214	$31,288	$31,309	$32,835	$33,053	$33,323	$31,190	$31,153	$31,205	$31,014
Low Capital Costs	$30,589	$30,806	$30,979	$30,896	$30,990	$30,976	$31,087	$32,691	$32,821	$33,102	$30,972	$30,930	$30,988	$30,764
High Capital Costs	$32,048	$32,202	$32,771	$32,407	$32,421	$32,563	$32,498	$33,656	$34,131	$34,434	$32,287	$32,284	$32,293	$32,128

Table 2. NPVRR (million 2016$) under 20-year horizon (truncated)

Future	Efficient Capacity 2021	RPS Wind 2018	Wind 2018 Long	Wind 2018	Wind 2018 + Solar PV 2021	Geothermal 2021	Wind 2018 + Solar PV 2018	Boardman Biomass 2021	Efficient Capacity 2021 + High EE	Wind 2018 + High EE	RPS Wind 2020	RPS Wind 2021	RPS Wind 2025	Efficient Capacity 2021 - Min Bank
Low Gas, No CO2, Low Load	$17,462	$17,455	$18,127	$17,703	$17,752	$17,786	$17,838	$18,874	$19,973	$20,146	$17,671	$17,613	$17,692	$17,692
Low Gas, No CO2, Ref Load	$18,010	$18,003	$18,675	$18,251	$18,300	$18,334	$18,386	$19,422	$20,521	$20,694	$18,219	$18,161	$18,240	$18,240
Low Gas, No CO2, High Load	$18,557	$18,550	$19,222	$18,797	$18,847	$18,881	$18,933	$19,969	$21,068	$21,241	$18,766	$18,707	$18,787	$18,786
Low Gas, Ref CO2, Low Load	$18,901	$18,999	$19,422	$19,169	$19,218	$19,257	$19,304	$20,322	$21,308	$21,529	$19,169	$19,121	$19,186	$19,079
Low Gas, Ref CO2, Ref Load	$19,728	$19,826	$20,249	$19,996	$20,045	$20,084	$20,131	$21,149	$22,135	$22,356	$19,996	$19,948	$20,013	$19,907
Low Gas, Ref CO2, High Load	$20,554	$20,652	$21,075	$20,822	$20,871	$20,910	$20,957	$21,975	$22,961	$23,182	$20,822	$20,774	$20,839	$20,733
Low Gas, High CO2, Low Load	$19,407	$19,569	$19,870	$19,692	$19,744	$19,779	$19,830	$20,826	$21,767	$22,017	$19,706	$19,673	$19,719	$19,547
Low Gas, High CO2, Ref Load	$20,362	$20,524	$20,825	$20,646	$20,699	$20,734	$20,784	$21,781	$22,722	$22,971	$20,661	$20,627	$20,674	$20,502
Low Gas, High CO2, High Load	$21,315	$21,477	$21,778	$21,600	$21,652	$21,687	$21,738	$22,734	$23,675	$23,925	$21,614	$21,581	$21,627	$21,455
Ref Gas, No CO2, Low Load	$17,931	$17,929	$18,523	$18,163	$18,217	$18,249	$18,303	$19,314	$20,402	$20,571	$18,107	$18,072	$18,124	$18,117
Ref Gas, No CO2, Ref Load	$18,593	$18,591	$19,185	$18,825	$18,879	$18,911	$18,965	$19,975	$21,064	$21,233	$18,769	$18,734	$18,785	$18,778
Ref Gas, No CO2, High Load	$19,253	$19,251	$19,845	$19,486	$19,540	$19,572	$19,625	$20,636	$21,724	$21,893	$19,430	$19,394	$19,446	$19,439
Ref Gas, Ref CO2, Low Load	$19,429	$19,496	$19,853	$19,653	$19,705	$19,742	$19,791	$20,794	$21,803	$21,985	$19,637	$19,606	$19,650	$19,572
Ref Gas, Ref CO2, Ref Load	**$20,347**	**$20,415**	**$20,772**	**$20,572**	**$20,624**	**$20,661**	**$20,710**	**$21,713**	**$22,722**	**$22,904**	**$20,555**	**$20,525**	**$20,568**	**$20,491**
Ref Gas, Ref CO2, High Load	$21,265	$21,333	$21,690	$21,490	$21,542	$21,578	$21,627	$22,630	$23,639	$23,821	$21,473	$21,443	$21,486	$21,409
Ref Gas, High CO2, Low Load	$19,977	$20,111	$20,352	$20,227	$20,282	$20,315	$20,367	$21,353	$22,303	$22,521	$20,217	$20,203	$20,226	$20,079
Ref Gas, High CO2, Ref Load	$21,026	$21,161	$21,402	$21,277	$21,331	$21,365	$21,417	$22,403	$23,353	$23,571	$21,267	$21,253	$21,275	$21,129
Ref Gas, High CO2, High Load	$22,075	$22,210	$22,450	$22,325	$22,380	$22,413	$22,466	$23,452	$24,401	$24,620	$22,315	$22,301	$22,324	$22,178
High Gas, No CO2, Low Load	$19,877	$19,901	$20,031	$19,948	$20,020	$20,040	$20,106	$21,007	$22,192	$22,247	$20,038	$19,987	$20,053	$20,023
High Gas, No CO2, Ref Load	$20,932	$20,955	$21,086	$21,003	$21,075	$21,095	$21,161	$22,062	$23,247	$23,302	$21,093	$21,042	$21,108	$21,078
High Gas, No CO2, High Load	$21,984	$22,008	$22,139	$22,055	$22,128	$22,147	$22,214	$23,115	$24,299	$24,354	$22,145	$22,095	$22,161	$22,131
High Gas, Ref CO2, Low Load	$21,396	$21,422	$21,367	$21,414	$21,483	$21,506	$21,569	$22,471	$23,632	$23,649	$21,518	$21,481	$21,528	$21,495
High Gas, Ref CO2, Ref Load	$22,668	$22,694	$22,640	$22,686	$22,755	$22,778	$22,841	$23,743	$24,904	$24,921	$22,790	$22,753	$22,801	$22,768
High Gas, Ref CO2, High Load	$23,938	$23,964	$23,910	$23,956	$24,025	$24,048	$24,111	$25,013	$26,174	$26,191	$24,060	$24,023	$24,071	$24,038
High Gas, High CO2, Low Load	$22,025	$22,067	$21,923	$22,026	$22,095	$22,117	$22,181	$23,082	$24,224	$24,232	$22,139	$22,113	$22,147	$22,096
High Gas, High CO2, Ref Load	$23,399	$23,441	$23,298	$23,400	$23,470	$23,491	$23,555	$24,457	$25,598	$25,607	$23,513	$23,487	$23,521	$23,471
High Gas, High CO2, High Load	$24,772	$24,814	$24,670	$24,773	$24,842	$24,864	$24,928	$25,829	$26,971	$26,979	$24,886	$24,860	$24,894	$24,843
Low Hydro Availability	$20,684	$20,838	$21,113	$20,965	$21,018	$21,056	$21,104	$22,110	$23,039	$23,285	$20,971	$20,941	$20,984	$20,820
Low VER Capacity Factor	$20,351	$20,420	$20,776	$20,577	$20,645	$20,665	$20,733	$21,718	$22,725	$22,908	$20,559	$20,530	$20,572	$20,495
High VER Capacity Factor	$20,185	$20,252	$20,485	$20,355	$20,414	$20,456	$20,508	$21,593	$22,583	$22,723	$20,429	$20,384	$20,446	$20,370
Low Capital Costs	$20,025	$20,115	$20,255	$20,176	$20,256	$20,239	$20,350	$21,500	$22,440	$22,572	$20,292	$20,244	$20,310	$20,213
High Capital Costs	$20,669	$20,716	$21,289	$20,968	$20,993	$21,082	$21,069	$21,925	$23,004	$23,236	$20,819	$20,807	$20,827	$20,770

Table 3. NPVRR (million 2016$) under infinite horizon (constant real costs beginning in 2050)

Future	Efficient Capacity 2021	RPS Wind 2018	Wind 2018 Long	Wind 2018	Wind 2018 + Solar PV 2021	Geothermal 2021	Wind 2018 + Solar PV 2018	Boardman Biomass 2021	Efficient Capacity 2021 + High EE	Wind 2018 + High EE	RPS Wind 2020	RPS Wind 2021	RPS Wind 2025	Efficient Capacity 2021 - Min Bank
Low Gas, No CO2, Low Load	$35,852	$35,998	$36,617	$36,094	$36,149	$36,251	$36,237	$38,363	$38,210	$38,419	$36,180	$36,138	$36,196	$36,042
Low Gas, No CO2, Ref Load	$38,367	$38,513	$39,133	$38,609	$38,664	$38,766	$38,753	$40,878	$40,726	$40,934	$38,695	$38,653	$38,711	$38,557
Low Gas, No CO2, High Load	$40,930	$41,076	$41,696	$41,172	$41,227	$41,329	$41,316	$43,441	$43,289	$43,497	$41,258	$41,217	$41,274	$41,120
Low Gas, Ref CO2, Low Load	$40,443	$40,884	$41,331	$41,018	$41,062	$41,171	$41,150	$43,057	$42,315	$42,852	$41,020	$40,988	$41,032	$40,582
Low Gas, Ref CO2, Ref Load	$44,907	$45,349	$45,796	$45,483	$45,527	$45,636	$45,615	$47,522	$46,780	$47,316	$45,485	$45,453	$45,497	$45,047
Low Gas, Ref CO2, High Load	$49,459	$49,901	$50,348	$50,035	$50,078	$50,187	$50,167	$52,074	$51,332	$51,868	$50,037	$50,005	$50,049	$49,598
Low Gas, High CO2, Low Load	$41,375	$41,964	$42,309	$42,080	$42,152	$42,225	$42,241	$44,142	$43,107	$43,779	$42,067	$42,050	$42,075	$41,476
Low Gas, High CO2, Ref Load	$46,656	$47,246	$47,591	$47,362	$47,434	$47,507	$47,522	$49,424	$48,389	$49,061	$47,349	$47,332	$47,357	$46,757
Low Gas, High CO2, High Load	$52,043	$52,632	$52,978	$52,749	$52,820	$52,894	$52,909	$54,810	$53,776	$54,448	$52,735	$52,718	$52,743	$52,144
Ref Gas, No CO2, Low Load	$38,030	$38,367	$38,948	$38,509	$38,578	$38,671	$38,667	$40,657	$40,073	$40,510	$38,512	$38,493	$38,523	$38,176
Ref Gas, No CO2, Ref Load	$42,021	$42,358	$42,939	$42,500	$42,569	$42,662	$42,658	$44,648	$44,064	$44,501	$42,503	$42,484	$42,514	$42,167
Ref Gas, No CO2, High Load	$46,095	$46,432	$47,013	$46,574	$46,643	$46,736	$46,732	$48,722	$48,138	$48,575	$46,577	$46,558	$46,588	$46,241
Ref Gas, Ref CO2, Low Load	$42,691	$43,083	$43,498	$43,255	$43,307	$43,408	$43,395	$45,234	$44,323	$44,840	$43,190	$43,176	$43,197	$42,796
Ref Gas, Ref CO2, Ref Load	**$48,306**	**$48,699**	**$49,114**	**$48,870**	**$48,922**	**$49,024**	**$49,011**	**$50,849**	**$49,938**	**$50,456**	**$48,805**	**$48,792**	**$48,813**	**$48,411**
Ref Gas, Ref CO2, High Load	$54,035	$54,427	$54,842	$54,599	$54,651	$54,752	$54,739	$56,578	$55,667	$56,184	$54,534	$54,520	$54,541	$54,140
Ref Gas, High CO2, Low Load	$43,698	$44,284	$44,604	$44,446	$44,525	$44,589	$44,614	$46,403	$45,180	$45,886	$44,355	$44,358	$44,359	$43,762
Ref Gas, High CO2, Ref Load	$50,118	$50,704	$51,024	$50,866	$50,945	$51,009	$51,034	$52,823	$51,601	$52,306	$50,775	$50,778	$50,779	$50,182
Ref Gas, High CO2, High Load	$56,669	$57,254	$57,574	$57,417	$57,496	$57,559	$57,584	$59,374	$58,151	$58,856	$57,326	$57,328	$57,329	$56,732
High Gas, No CO2, Low Load	$42,568	$43,165	$43,365	$43,244	$43,352	$43,413	$43,441	$45,181	$44,039	$44,692	$43,269	$43,235	$43,279	$42,675
High Gas, No CO2, Ref Load	$49,072	$49,670	$49,869	$49,748	$49,856	$49,917	$49,945	$51,685	$50,543	$51,196	$49,773	$49,739	$49,783	$49,179
High Gas, No CO2, High Load	$55,699	$56,297	$56,497	$56,376	$56,484	$56,544	$56,573	$58,310	$57,170	$57,824	$56,401	$56,367	$56,411	$55,806
High Gas, Ref CO2, Low Load	$47,219	$47,447	$47,520	$47,558	$47,649	$47,716	$47,737	$49,408	$48,421	$48,732	$47,509	$47,489	$47,514	$47,279
High Gas, Ref CO2, Ref Load	$54,719	$54,948	$55,021	$55,059	$55,150	$55,217	$55,238	$56,909	$55,921	$56,233	$55,010	$54,990	$55,015	$54,779
High Gas, Ref CO2, High Load	$62,370	$62,599	$62,672	$62,710	$62,801	$62,868	$62,889	$64,560	$63,573	$63,884	$62,661	$62,641	$62,666	$62,430
High Gas, High CO2, Low Load	$48,264	$48,666	$48,669	$48,772	$48,886	$48,917	$48,974	$50,600	$49,309	$49,791	$48,704	$48,694	$48,706	$48,297
High Gas, High CO2, Ref Load	$56,581	$56,983	$56,986	$57,089	$57,203	$57,234	$57,291	$58,917	$57,625	$58,107	$57,021	$57,011	$57,023	$56,613
High Gas, High CO2, High Load	$65,069	$65,471	$65,474	$65,577	$65,690	$65,722	$65,779	$67,405	$66,113	$66,595	$65,509	$65,499	$65,511	$65,101
Low Hydro Availability	$49,171	$49,806	$50,157	$49,975	$50,029	$50,134	$50,118	$51,988	$50,741	$51,499	$49,905	$49,892	$49,913	$49,269
Low VER Capacity Factor	$48,327	$48,730	$49,145	$48,902	$49,003	$49,056	$49,093	$50,881	$49,954	$50,484	$48,836	$48,823	$48,844	$48,431
High VER Capacity Factor	$47,239	$47,625	$47,935	$47,772	$47,839	$47,957	$47,936	$50,024	$48,972	$49,466	$47,768	$47,740	$47,780	$47,384
Low Capital Costs	$46,939	$47,376	$47,581	$47,485	$47,595	$47,584	$47,694	$49,857	$48,700	$49,216	$47,527	$47,492	$47,541	$47,096
High Capital Costs	$49,674	$50,021	$50,647	$50,255	$50,250	$50,463	$50,328	$51,842	$51,176	$51,695	$50,083	$50,091	$50,085	$49,726

Summary of Reply Comments

Action Plan

- Consistent with the Commission's IRP Guidelines, the Action Plan identifies resources to be procured and a proposed acquisition strategy.
- The Commission and stakeholders have historically favored flexible procurement plans.
- The IRP Action Plan is agnostic to ownership structure and is not biased against out-of-state wind.
- A term-limited procurement strategy is problematic.
- The renewal of existing hydro contracts and execution of new QF contracts does not change the IRP Action Plan.
- PGE is exploring opportunities to acquire existing capacity.
- Issues pertaining to the design and conduct of the RFP should be considered in the RFP docket.
- PGE has identified a potential benchmark wind resource and is exploring the development of an energy storage site.

RPS Analysis

- The value of early RPS action is robust for 100% and 80% PTC-eligible resources with COD 2020 and 2021, and is not significantly impacted by the minimum REC bank constraint.
- Procurement of 175 MWa of incremental renewables balances near-term and net present value economic views.
- The benefits of early RPS action remain after accounting for more rapid LCOE declines.
- PGE's findings for early RPS action are robust across additional sensitivities, including zero minimum REC bank, zero load growth, and 20-year NPV assumptions.
- PTC carryforward balances will not eliminate the benefits of early RPS action.
- Short-term reliance on unbundled RECs does not offset the value of early RPS action and a long-term strategy of relying on unbundled RECs introduces additional price risk.

Load Forecast

- PGE's load forecast is based on reasonable assumptions and a sound methodological approach.
- In these comments, PGE provides analysis of the impact of its latest load forecast on resource need.
- The LBNL study is a flawed comparative analysis of PGE's load forecasting performance.
- PGE has provided sufficient detail to support its load forecast and comply with IRP Guideline 4b.
- PGE's load forecast appropriately considers uncertainty.
- PGE does not speculate on the future direct access activities of its customers.
- PGE implemented Itron's recommendations concerning industrial load growth.
- At Staff's request, PGE performed sensitivity analysis for certain individual customer forecasts.
- PGE includes impacts of distributed renewables implicitly in its load forecast models.

Capacity Adequacy and Contribution

- PGE uses sound capacity adequacy modeling.
- PGE's LOLE standard is an appropriate metric to assess long-term resource adequacy to meet customers' demand.
- Planning reserve margins alone do not provide a meaningful comparison of resource adequacy assessments.
- The stochastic treatment of load in RECAP is reasonable.
- PGE's capacity need is not reduced by the Energy Imbalance Market.
- PGE used RECAP to calculate renewable capacity contributions.
- PGE's resource adequacy study identifies the quantity of need based on an annual resource; however resources with different seasonal or hourly availability can contribute to meeting the capacity need.
- Staff's resource adequacy assessment conflates resource need with actions. ICNU's assessment has several material flaws.

- PGE continues to evaluate resource adequacy needs in response to updated load forecasts and recently signed contracts.

Market Access

- PGE assumes unlimited access to market energy in its economic modelling of portfolios and includes portfolios which maintain open positions.

- PGE's assumptions concerning reliance on the spot market in resource adequacy assessments are reasonable.

- PGE's IRP spot market access assumptions are not interchangeable with PacifiCorp's Front Office Transaction assumptions.

- Multiple regional assessments forecast a capacity shortage in 2021.

Dispatchable Capacity Need

- PGE's third party flexibility study leveraged the best available modeling methodologies for flexibility adequacy and highlighted the need for continued efforts to incorporate operational analysis into future long-term planning exercises.

- The characterization of resource options in the REFLEX study was consistent with the available third party cost and performance data.

- The dispatchable capacity need identified for 2021 is an important constraint for the procurement of resources to meet the flexibility needs of evolving systems regardless of the near-term RPS strategy.

Energy Efficiency

- The Energy Trust appropriately does not speculate about the adoption of the currently unknown technologies.

- PGE does not own or control Energy Trust data.

- The large customer EE spending limits have not been met; and, if met, would not materially affect resource need.

- Sierra Club's comparison of PGE's and NWPCC's forecast of EE savings is misleading and its characterization of PGE forecasted EE savings relies on misinterpreted figures.

- The cost- effective threshold, avoided T&D costs, and conservation adder are appropriate.

Demand Response

- The DR targets modeled in the 2016 IRP are based on the identified DR potential with reasonable adjustments to account for practical constraints to implementation.

- While DR targets encompass a range of DR types, the IRP models the full DR fleet as firm and dispatchable. PGE will continue to pursue more sophisticated DR modeling efforts in future IRPs.
- The decline in DR resources over the 2021-2031 timespan in the high DR adoption future is driven by the inclusion of opt-out programs.
- AURORA simulates a unique DR dispatch profile for each year.
- Renewable integration use cases will be evaluated in PGE's current and forthcoming pilots, where appropriate.

Capacity Products

- PGE's reliance on proxy resources in portfolio evaluation is consistent with common industry practice.
- The economic value of shorter-than-life resource durations is highly sensitive to contract pricing and terms, and therefore cannot be evaluated in a generic way within an IRP.
- PGE explored seasonal contract economics in IRP Section 5.1.4.1.

Hydro Contracts

- For IRP planning purposes, PGE does not speculate as to whether or on what terms hydro contracts might be renewed.
- PGE does not evaluate specific hydro contract options in the IRP because quantities and terms are unknowable.
- The IRP explains the drop off in hydro between 2014 and 2017.

Distributed Energy Resources (DER)

- PGE's treatment of DER is reasonable.

Portfolio Construction

- PGE's portfolio construction methodology ensures that resource options are compared on a consistent basis.
- The actionable portfolios investigate a wide range of procurement options and identify a wide range of potential future costs.
- The portfolio analysis used to justify ICNU's assertions lacks the necessary rigor to make meaningful resource comparisons.

Scenario-based Risk Analysis

- The findings in the IRP and recommendations within the Action Plan are robust across all modeled futures, including additional low gas price futures.

- PGE evaluated the risk associated with Efficient Capacity resource procurement across a wide range of carbon price futures and considered additional policy-driven risks.

Planning Horizon and End Effects

- The conclusions in the IRP are robust across additional planning horizon sensitivities.
- End-effects are appropriately captured in the IRP for the modeled generic resources.

Portfolio Scoring

- The cost metric applied in the 2016 IRP remains a reasonable estimate of expected portfolio costs.
- Consistent with prior acknowledged IRPs, the variability metric addresses the asymmetry in the impacts of higher than expected and lower than expected costs to customers.
- The severity metric is consistent with prior acknowledged IRPs and the specific recommendations of Parties in the 2009 IRP.
- The durability metric provides insight regarding relative portfolio performance that is important in scenario analysis and not captured by other risk metrics.
- PGE agrees that invariant scoring is worthy of discussion in future IRP public processes, but it does not impact the Preferred Portfolio in the 2016 IRP.
- The findings in the 2016 IRP are robust to sensitivities around scoring methodology, weighting, and the NPVRR calculation.

CO_2 Modeling

- Coal capacity modeled in the West reflects announced retirements and additional economic retirements associated with specific carbon price futures.
- Resource dispatch and economics take into account resource-specific carbon emissions intensities for both PGE resources and resources across the West.
- The emissions rate applied to purchases/sales for carbon emissions reporting is a simplification and does not impact resource economics or portfolio scoring in the 2016 IRP.

Transmission

- Acquisition of existing transmission rights, which are constrained, would offset much of the NPV benefit of the Diverse Wind portfolio.
- New transmission makes the Diverse Wind portfolio significantly more costly than the Preferred Portfolio.
- Speculation as to future availability of transmission should not justify forgoing significant PTC benefits.

- NIPPC's suggestion that the IRP should contemplate conversion to BPA Network Integrated Transmission Service is without merit.

Distribution Planning

- PGE supports efforts to align the various regulatory processes related to distribution planning and is willing to work with Staff and others on this effort.

North Mist Expansion

- PGE provides additional information on the North Mist Expansion.

Compliance with IRP Guidelines

- PGE has fully complied with the Commission's IRP Guidelines.