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**V. Denise Saunders**
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June 23, 2017

***Via Electronic Filing***

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 is Portland General Electric Company's ("PGE") Final Reply Comments.

Thank you in advance for your assistance.

Sincerely,

V. Denise Saunders
Associate General Counsel

VDS:bop

Enclosure

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

**DOCKET NO. LC 66**

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| In the Matter of<br><br>PORTLAND GENERAL ELECTRIC COMPANY<br><br>2016 Integrated Resource Plan. | **PORTLAND GENERAL ELECTRIC COMPANY's**<br><br>**FINAL REPLY COMMENTS** |

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# 1. Introduction

### 1.1. Collaboration produces better results

Portland General Electric Company (PGE) appreciates the amount and quality of stakeholder involvement in our 2016 Integrated Resource Planning (IRP) process. As the formal proceedings before the Public Utility Commission of Oregon (OPUC) near conclusion, we want to thank OPUC staff and all who have participated for their constructive participation and thoughtful comments throughout the process. PGE hosted nine public workshops attended by stakeholder organizations and individuals, provided responses to 355 data requests, and numerous emails or comments from stakeholders and the public, and participated in four OPUC public meetings.

Active public and stakeholder participation ensured the consideration of a diversity of views, priorities, and issues impacting PGE's customers and the state of Oregon. The feedback and suggestions we received also helped strengthen PGE's analysis and provided the foundation for further improvements in future resource plans.

Ten parties submitted final comments in this docket: [1]

- OPUC staff (Staff)
- Citizens Utility Board (CUB)
- Industrial Customers of Northwest Utilities (ICNU)
- Sierra Club
- National Grid
- Renewable Northwest (RNW)
- Oregon Department of Energy (ODOE)
- Northwest Energy Coalition (NWEC)
- Northwest and Intermountain Power Producers Coalition (NIPPC)
- Ed Averill on behalf of the Northwest Climate Methane Task Force.

PGE appreciates this opportunity to provide a final response to these parties' comments.

[1] We note that the Oregon Lawyers for Good Government filed comments on PGE's IRP three days before PGE's Final Comments were due. The Oregon Lawyers for Good Government has not intervened in PGE's IRP docket and has not complied with the procedural schedule issued by the ALJ in the docket. PGE notes that the issues raised in the comments are generally addressed in PGE's Reply Comments and Final Reply Comments. Nonetheless, the Commission should refuse to consider the improperly filed comments.

### 1.2. PGE planning reflects the values of our customers and our communities

From the beginning of this process, PGE has remained committed to working in collaboration with stakeholders to produce a plan that reflects a balanced approach to meeting our customers' energy needs, using increasingly sustainable energy solutions. This IRP retains PGE's essential focus on safe, reliable, and affordable electricity while reflecting a future focused on more energy efficiency, demand response and renewable resources, and fewer greenhouse gas emissions.

While reliability and affordability remain foundational to our planning efforts, PGE is committed to doing our part to combat climate change, and will continue to work with our customers to meet Oregon's progressive clean energy standards.

It is clear that regardless of what happens at the federal level, state and local actions to reduce carbon and increase our region's reliance on clean and renewable energy will only continue to accelerate.

PGE's customers, government leaders, and the majority of stakeholders want us to take concrete steps to address climate change. On June 5, following the U.S. withdrawal from the Paris Climate Agreement, more than 1,200 governors, mayors, businesses, and colleges and universities across the country declared their intent to ensure the U.S. remains a global leader in reducing carbon emissions.

Dozens of PGE business customers, large and small, were among those signing on. So were Oregon's governor, Portland's mayor, Multnomah County's chair and the chair of Metro, our regional government. So were the presidents of Portland State University, Portland Community College, Mt. Hood Community College, the University of Oregon, Oregon State University, Western Oregon University, and Southern Oregon University. And so was PGE.

At the same time, the City of Portland and Multnomah County each passed resolutions stating they will meet 100 percent of their economy-wide energy needs with renewable resources by 2050. We support them in their journey to this goal. Collectively, we need to determine how PGE and our customers will meet this goal, but we know that more efficiency, renewables, electrification, and greenhouse gas reductions—along with smart grid advancements and other technologies yet to be discovered—will be essential in getting there.

In addition, PGE residential customers want their energy to increasingly come from more renewable resources. For the past seven years, PGE has been ranked the nation's #1 Green Power Program by the U.S. Department of Energy, based on the total number of customers choosing renewable power.[2] PGE customers and the Energy Trust of Oregon have also helped make PGE one of the top 10 utilities in the nation for energy efficiency.[3]

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[2] http://www.nrel.gov/analysis/pdfs/utility-green-power-rankings.pdf
[3] http://aceee.org/blog/2017/06/results-are-here-are-most-energy#.WUFXoNb-5pI.twitter

Throughout the IRP process, stakeholders have made clear their expectations that we will increase renewable resources and decrease carbon emissions. For the past several months, these stakeholders – including the OPUC – have encouraged PGE to look for ways to avoid building more greenhouse gas-producing resources. As a result, PGE has been working with power producers in the region to identify existing resources that may be available to help meet our capacity need. We are optimistic about the possibilities that exist.

To protect the environment, reflect our customers' values – and save them money – PGE remains convinced that early action to acquire 175 MWa of renewable resources is the most appropriate action. Bringing new renewables onto the grid (as opposed to solely using banked renewable energy credits) achieves real reduction in greenhouse gas emissions, while also delivering the value of federal tax credits and favorable market conditions to our customers.

PGE will continue to work with our customers and stakeholders to develop innovative solutions that strengthen our economy while protecting our environment for future generations.

### 1.3. We embrace the principles of integrated resource planning

PGE addresses many challenges and questions in our 2016 Integrated Resource Plan. As the electricity industry changes and rapid technological advances continue to present resource planning with new challenges, future IRPs or IRP updates will continue the evolution of the robust collaborative process. Such is the nature of the "well organized, thorough, and flexible method of [long-term resource] planning," adopted by the Commission in Order No. 89-507[4] and refined in Order No. 07-002.[5]

Oregon's method of resource planning relies on the balanced consideration of four substantive elements:[6]

- Supply and demand resources;
- Risk and uncertainty;
- The best combination of costs and associated risks; and
- Alignment with "the long-run public interest" provided in state and federal energy policies.

While the OPUC has made modifications to the IRP Guidelines at various points, these four principles have withstood electric industry changes, technological advances, extreme market conditions, and the "changing customer expectations, regulatory mandates, and increasing concern about carbon emissions"[7] noted in Staff's Final Comments.

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[4] *In re Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon*, UM 180, Order No. 89-507 at 2 (Apr. 20, 1989) (original order adopting least cost planning).
[5] *In re Investigation into Integrated Resource Planning*, UM 1056, Order No. 07-002 at 2 (Jan. 8, 2007) (corrected by Order No. 07-047).
[6] *Id.*
[7] Staff's Final Reply Comments at 3.

Oregon's IRP principles have established a process that focuses on long-term planning to balance cost and risk over time, rather than solely considering the minimization of short-term costs. It is intended to be a two- to three-year process of public engagement, planning, and evaluation that informs PGE's business decisions regarding future resource actions. Because of the robust process created by both the IRP and Competitive Bidding Guidelines,[8] a utility's ultimate decision-making authority remains intact and the Company takes full "benefit of the information and opinion contributed by the public and by the Commission."[9] That decision-making must include many inputs, specifically including consideration of customer needs and expectations, costs and risks, industry and market changes, regulatory mandates, and future prudence reviews.

PGE relied on these principles and the current IRP Guidelines in developing its 2016 IRP, constructing the proposed Action Plan, and responding to parties' comments. PGE's IRP process involved thoughtful, reasoned, and studied analysis and discussions with Staff, stakeholders, consultants, and members of the general public. Over an 18-month period, PGE developed and presented the analysis for this IRP. This lengthy period provided time for the "full exploration of risks and uncertainties" Staff speaks of in their Final Comments.[10] As a result, PGE's 2016 IRP includes portfolio analysis that not only considers the current state of the electricity industry, but also anticipates future changes in the industry, technology, customer expectations, regulatory mandates, and the like.

In the 2016 IRP, PGE sought input from stakeholders on the development of an IRP within the context of the current IRP Guidelines. Given the evolving and uncertain nature of the industry, PGE put significant effort into incorporating quantifiable long-term uncertainties into the existing IRP framework. The Company acknowledges that there will always be opportunities to improve the IRP process through modification of the IRP Guidelines, and that the Commission may choose to continue its practice of reviewing and modifying the IRP Guidelines when necessary. However, it is PGE's view that such consideration should incorporate thoughtful engagement of stakeholders in an open and purposeful process. PGE, therefore, does not take up questions regarding future modifications to the IRP process in these comments and is instead open to their thorough debate in a future docket should the Commission deem it appropriate.

For convenience, PGE has arranged its reply comments in a topical order similar to that used by Staff.

## 2. Long-term Resource Planning

The IRP Guidelines reflect the core values of long-term resource planning in Oregon and the industry as a whole. When reviewing utility IRPs, the Commission ensures that a proposed IRP "adhere[s] to the procedural and substantive requirements" set forth in the IRP Guidelines.[11]

[8] *In re Investigation Regarding Competitive Bidding*, UM 1182, Order No. 06-446 (Aug. 10, 2006).
[9] *In the Matter of PacifiCorp 2008 Integrated Resource Plan*, LC 47, Order No. 10-066 at 27.
[10] Staff's Final Comments at 4.
[11] *In re: PacifiCorp dba, Pacific Power, 2013 Integrated Resource Plan*, LC 57, Order No. 14-252 at 1.

Staff, ICNU, and CUB remain concerned that near-term procurement of renewables, in part to meet long-term RPS obligations, does not address a need within the Action Plan window. Staff also seems unconvinced that a regulatory requirement should be used to justify a resource action, stating: "PGE's [sic] justifies the 175 MWa early-action renewable resource is based upon a 'need' that arises essentially from regulatory requirements."[12] As a result, Staff asserts that some portions of PGE's Action Plan do not comply with the Guidelines. PGE believes that Staff's assertions are based on a misinterpretation of specific Commission orders and the IRP Guidelines—particularly Guidelines 1 and 4(n). In some cases, as described below, specific misinterpretations of the IRP Guidelines serve to undermine the core values of long-term resource planning and call into question the reasonableness of parties' resulting recommendations. PGE maintains that, consistent with the IRP Guidelines, a long-term regulatory need can, and should, contribute to the justification for a resource action within the Action Plan window.

### 2.1. Planning under uncertainty

> ***The IRP Guidelines establish a process for utilities to pursue near-term actions with consideration of long-term uncertainties.***

The IRP process is not a short- or mid-term planning process. It is a process established to ensure that a utility's short-term actions reflect and fulfill the long-term needs of its customers with consideration of long-term uncertainties. The Guidelines and related Commission orders lay out a thoughtful process for long-term, least-cost, least-risk resource planning, and a clear purpose for the IRP Action Plan. Despite the considerable and thorough analysis presented both in the 2016 IRP and in PGE's Reply Comments, Staff believes that the "inexorable changes that are coming"[13] are so great that the Company should not pursue long-term resources.

Risk and uncertainty are inherent considerations in any long-term planning exercise.[14] This has been true since the inception of Integrated Resource Planning and will continue into the future. Staff appears to agree that the future may bring increased levels of uncertainty, stating at the public meeting before the Commission on February 16, 2017, that there's "[u]ncertainty because of the pace of technological change and we shouldn't expect that to change…we might expect it to get worse."[15] If there is a sense that uncertainty is increasing and Staff's position is that the present level of uncertainty is too great to allow a long-term resource action, then the logical conclusion is that there will never again be enough certainty to allow for long-term resource actions. This is an unprecedented, as well as untenable approach to long-term planning that would limit the utility to near-term actions, potentially jeopardizing resource adequacy and affordability. Additionally, to delay or avoid a resource action that is the best combination of costs and risks, and aligns with "long-run public interests," across a range of plausible assumptions, merely due to unquantified uncertainty, runs counter to Oregon's IRP Guidelines.

[12] Staff's Final Comments at 7.
[13] Staff's Final Comments at 4.
[14] Order No. 07-002 at 5, Appendix A at 1.
[15] Comments of Staff before the Commission during the LC 66, February 17, 2017 Special Public Meeting at approximately 1:01:40.

### 2.2. Two to four-year Action Plan window

> ***Actions acknowledged within the Action Plan window may address needs outside the 2-4 year Action Plan window.***

Since Order No. 89-507, the Commission has required Oregon utilities to focus on long-term resource planning. Within this long-term planning framework, the Commission expected utilities to 1) develop a short-term plan of action and 2) implement the plan of action "to bring about the least-cost provision of power."[16] Order No. 07-002 refined the "short term plan of action," by extending the action plan window and limiting acknowledgement to activities required in the next two to four years to meet a long-term system need.[17] However, the goal or purpose of this short-term action plan remained the same—to apprise the Commission of the activities the utility would pursue in order to ensure the successful implementation of its proposed long-term resource procurement.

Staff's final comments state that Guideline 4(n), in conjunction with Guideline 1(c), requires a utility to identify activities the company plans to undertake "to *meet system needs* in the two to four year Action Plan period" (emphasis added).[18] PGE disagrees with this interpretation.

IRP Guideline 4 lays out the required components of the IRP.[19] Guidelines 4(a) through 4(m) outline specific requirements of the analysis, including the "[s]election of a portfolio that represents the best combination of cost and risk for the utility and its customers."[20] None of these Guidelines limit the identification of need, the construction of portfolios, or the evaluation of portfolios to considerations solely within the Action Plan window. The only guideline that makes reference to the two- to four-year Action Plan window is Guideline 4(n), which states that the IRP must include:

> *An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.*

PGE reads the clear language of Guideline 4(n) to mean that an Action Plan is a short-term (two to four years) plan or strategy for meeting the long-term resource plan identified through IRP analysis. However, in this docket, PGE reads Staff comments to be advancing an interpretation of the Action Plan period that contradicts Commission precedent, the IRP Guidelines, and the purpose of long-term resource planning. Staff asserts that actions taken during the action plan period must meet near-term system needs in order to be eligible for acknowledgement.[21] This argument directly implies that the utility must bring the identified resource online during the two- to four-year action plan window. This focus solely on near-term system need in the Action

[16] Order No. 89-507 at 9.
[17] *See* Order No. 07-002, Appendix A at 32; *see also* Order No. 89-507 at 11 (requiring a two-year action plan).
[18] Staff's Final Comments at 8.
[19] Order No. 07-002, Appendix A at 7 (as corrected by Order No. 07-047).
[20] *Id.* at 8, IRP Guideline 4(l).
[21] Staff's Final Comments at 8.

Plan horizon would unreasonably change the IRP from a long-term planning instrument to a short- to mid-term planning document.

To support its assertions, Staff relies on five Commission orders. PGE believes that Staff's misinterpretation of Guideline 4(n) stems from a fundamental misreading of the facts and holdings of these Commission orders as shown in the three orders discussed below.

**Order No. 08-232**

Staff relies on PacifiCorp's (PAC) 2007 IRP acknowledgement order (Order No. 08-232), to bolster its argument that the Commission only acknowledges action items if they meet a short-term need. Staff asserts that because PAC's analysis showed that the Company would be "capacity deficient system-wide beginning in 2010," the Commission only acknowledged action items that supported this 2010 need.[22] Staff, however, misconstrues the facts of the docket.

Commission Staff recommended acknowledgment of most of the action items in PAC's 2007 IRP but proposed modifications to four of the action items. [23] While each of the four action items focused on securing resources between 2012 and 2014, which was outside the action plan period, Staff did not raise any concerns with the timing of the resource actions.[24] The Commission stated it would have acknowledged these four items, with Staff's modifications, but the Company raised an issue with Staff's modifications, which led the Commission to deny acknowledgement of these four action items.[25] Thus, a full reading of Order No. 08-232 makes clear that it was not the fact that the resource need was outside the action plan period that barred acknowledgment, but another matter entirely.

**Order No. 08-246**

Staff also looks to the acknowledgement order from PGE's 2007 IRP to support its claim that a long-term regulatory requirement does not justify a near-term investment. Specifically, Staff relies on Order No. 08-246 to argue that the Commission only acknowledges Renewable Portfolio Standard (RPS)-related actions that fall within the Action Plan window.[26] Under Senate Bill 838, PGE faced an RPS obligation of 5% of retail energy deliveries in 2011, which increased to 15% in 2015.[27] PGE's 2007 IRP Action Plan proposed renewable resource actions (including the procurement of 218 MWa of renewables) designed to meet the 2015 RPS obligation.[28]

In this matter, Staff incorrectly assumes that PGE's 2007 renewable acknowledgement was limited to the 2011 need, and concludes that this is the reason why the Commission acknowledged PGE's proposed renewable resource actions (while denying the remainder of the

[22] Staff's Final Comments at 8.
[23] *In re PacifiCorp, dba Pacific Power, 2007 Integrated Resource Plan*, LC 42, Order No. 08-232 at 10-11 (Apr. 24, 2008).
[24] *Id*. At 10-11.
[25] *Id.* at 34.
[26] Staff's Final Comments at 9.
[27] *Portland General Electric Company's 2007 Integrated Resource Plan* at 97 (Jun. 29, 2007).
[28] *In re Portland General Electric Company 2007 Integrated Resource Plan*, LC 43, Order No. 08-246 at 4 (May 6, 2008).

Company's proposed action items).[29] To the contrary, PGE's renewable resource need was not in 2011, but in 2015—eight years after the filing of its 2007 IRP. The Commission found PGE's resource actions to be reasonable and acknowledged the procurement of additional renewables to meet the 2015 RPS need.

**Order No. 10-457**

Finally, Staff holds up pollution control for PacifiCorp's Wyodak plant as further evidence of a "higher degree of scrutiny on proposed actions for needs outside the near term."[30] Staff mistakenly states that PacifiCorp's 2013 IRP "sought to secure acknowledgement of an SCR upgrade for the *Wyodak* facility (emphasis added)."[31] PacifiCorp did not include pollution controls for "Wyodak" in its 2013 IRP, rather coal resource actions focused on Naughton Unit 3, Hunter Unit 1, Jim Bridger Units 3 and 4, and Cholla Unit 4.[32] The Environmental Protection Agency (EPA) did not address regional haze requirements for Wyoming until May 28, 2013, approximately two months following the filing of PacifiCorp's 2013 IRP. The EPA would require Selective Non-Catalytic Reduction (SNCR) on the Wyodak plant.[33] The final Wyoming Federal Implementation Plan (FIP) was issued January 10, 2014, requiring Selective Catalytic Reduction (SCR) equipment for Wyodak by March 2019. Following that, Staff recommended "New Action Item 8f. – Wyodak," which established the analysis framework for future pollution controls on PacifiCorp's coal fleet.[34] In short, PacifiCorp did not request acknowledgement of any actions for Wyodak in its 2013 IRP, contrary to Staff's assertions.

As shown above, the Commission, consistent with Guideline 4(n), neither limits the identified resource need to the Action Plan window nor requires that the identified resource meet system needs during the Action Plan window. Guideline 4(n) simply requires a utility to provide the Commission a short-term roadmap of the actions the utility deems necessary to implement the identified long-term resource plan. The Commission then reviews the Action Plan to determine whether it aligns with the four substantive elements undergirding Oregon's resource planning process. Staff's proposed interpretation of Guideline 4(n) would have utilities and the Commission ignore element four, "[a]lignment with "the long-run public interest" provided in state and federal energy policies." This particular element of resource planning requires the utility to exercise foresight and analyze the reasonable expectations that current and future regulatory requirements may place on utilities. PGE's proposed Action Plan is consistent with the foundational principles of resource planning and the Guidelines.

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[29] Staff's Final Comments at 9.
[30] *Id.*
[31] *Id.*
[32] *See PacifiCorp's 2013 Integrated Resource Plan*, at 250, Table 9.1 – 2013 IRP Action Plan.
[33] *See, In re PacifiCorp, dba Pacific Power, 2011 Integrated Resource Plan*, LC 57, PacifiCorp's Reply Comments at 8.
[34] *See, In re PacifiCorp, dba Pacific Power, 2011 Integrated Resource Plan*, LC 57, Staff Report for Public Meeting dated March 4, 2014 at 9. http://www.puc.state.or.us/meetings/pmemos/2014/031714/reg1-LC%2057.pdf.

### 2.3. Flexibility within the Action Plan

> ***The IRP and RFP Guidelines require both processes to be flexible in order to address the uncertainties and risks involved in resource planning.***

The detailed analysis in the 2016 IRP and thoughtful feedback from stakeholders led PGE to design a flexible and reasonable Action Plan. PGE's proposed Action Plan includes the potential for renewable and capacity Requests for Proposal (RFP) processes. These processes allow for the selection of resources of varying size and duration. More importantly, the RFP process—"a means to promote and improve the resource actions identified in the utility's IRP...Action Plan"[35]— provides an opportunity for additional exploration of the appropriate resource options to meet customers' needs. As the Commission noted in Order No. 06-446:

> *Changes occur from the time an Action Plan is acknowledged to when an RFP is released. The changes may be simple, due merely to the passage of time, or dramatic, such as the Western power crisis in 2000. While a utility's Action Plan establishes a roadmap, it is not in the customer's best interest for any utility to march lockstep without any deviation from the plan. We have found that flexibility is important in meeting the [Competitive Bidding Goals]*.[36]

Because Action Plans are subject to regular evaluation and updating, [37] it is clear that the Commission (and parties to the 1989 and 2007 IRP investigation dockets) intended action plans to remain flexible. This flexibility would be significantly restricted if the Commission limits the identified resource need to the Action Plan window. Furthermore, given the lengthiness of not only the resource planning process, but also the resource acquisition process,[38] flexibility is necessary to allow utilities to take advantage of unforeseen opportunities and mitigate the uncertainties inherent in long-term planning. Under Staff's interpretation of the Action Plan period, resource acquisition may be functionally limited to existing resources only. Under this limited view, long-lead time resources such as pumped hydro, biomass, and combined-cycle combustion turbines would not be viable resource options.

It is clear that the Commission designed the IRP and RFP Guidelines to be flexible in order to address the uncertainties and risks involved in resource planning. In the comments that follow, PGE describes how the 2016 IRP addressed uncertainties and risks within the IRP process, both prior to filing the IRP and throughout the OPUC process. The Company also describes how it intends to make use of the flexibility embedded within the Action Plan in order to meet customers' near- and long-term needs with the best combination of cost and risk, and with the best available information. PGE includes discussion of its efforts to solicit proposals and

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[35] *In re Investigation Regarding Competitive Bidding*, Order No. 06-446 at 2, UM 1182, (quoting Staff's Reply Comments at 7.)

[36] *Id.*

[37] IRP Guideline 3(a) requires a utility to "file an IRP within two years of its previous IRP acknowledgement order." Additionally, Guideline 3(g) requires utilities to file an annual update, following acknowledgement of the action plan, which "[d]escribes what actions the utility has taken to implement the plan," 2) assesses "what has changed since the acknowledgment order that affects the action plan;" and 3) "[j]ustifies any deviations from the acknowledged action plan."

[38] *See*, *PGE's 2016 IRP*, Appendix K.

negotiate bilateral contracts for existing hydro and natural gas resources; activity which is arguably outside of the traditional IRP/RFP process but is responsive to Commission, Staff and stakeholder feedback.

## 3. RPS Actions

PGE appreciates the continued thoughtful dialogue around the Company's proposed near-term RPS procurement action. Several Parties have expressed support for PGE's proposal to pursue RPS resources in the near-term to capture the value of the PTC.[39] In addition, NWEC and RNW express a desire for a subsequent renewables RFP to allow for procurement of up to 300 MWa.[40] And while not expressing support for a renewables RFP, CUB states that "[t]he analysis provided in PGE's Reply Comments supports the position that investment in wind resources is consistent with least cost/least risk procurement."[41] Staff, CUB, and ICNU express concerns regarding: the justification of resource actions on the basis of a long-term regulatory need; the appropriateness of PGE's risk analysis; issues of intergenerational equity; and prospects for wind repowering. PGE explores these topics below.

### 3.1. Regulatory need

> ***The IRP Guidelines require PGE to consider statutory and regulatory requirements, like RPS obligations, over time in its evaluation of resource options.***

Staff, ICNU, and CUB remain concerned that near-term procurement of renewables, in part to meet long-term RPS obligations, does not address a need within the Action Plan window. As discussed in Section 2.2, actions identified within the Action Plan window need not address only those needs that occur within the Action Plan window. Staff also seems unconvinced that a regulatory requirement should, in part, justify a resource action, stating within its critique of the proposed RPS action that "PGE's [sic] justifies the 175 MWa early-action renewable resource is based upon a 'need' that arises essentially from regulatory requirements."[42] Contrary to Staff's apparent belief, IRP Guideline 1(d) requires the action plan to "[be consistent with the long-run public interest as expressed in Oregon and federal energy policies." Hence, PGE must plan for any needs that arise, due to state policies such as Senate Bills 838 and 1547, within the IRP.

Staff and ICNU's suggestion that it is inappropriate to procure RPS-eligible resources in advance of an RPS "need" stems from a crucial misinterpretation of Oregon's RPS obligations. Importantly, the RPS obligations established by SB 838 and SB 1547 are fundamentally different from traditional long-term planning needs that require capacity availability or energy generation contemporaneously in the year of the need. Oregon's RPS obligations require the utility to <u>retire</u> an established volume of RECs in the compliance year, not to generate an established volume of RECs in the compliance year. The REC banking provisions in Senate Bills 838 and 1547 specifically allow for a difference between the year of REC generation and the year of REC

[39] NWEC at 1; ODOE at 5; RNW at 1; NIPPC at 1.
[40] NWEC at 6; RNW at 1.
[41] CUB at 5.
[42] Staff's Final Comments at 7.

retirement in order to reduce compliance costs and risks over time. These provisions establish RPS obligations not as resource needs tied to a specific year, as the industry is accustomed to considering in long-term planning exercises, but as regulatory requirements that a utility must meet in each year through resource actions that the utility may take over several years. In fact, the legislature specifically contemplated the potential value of near-term RPS action to meet compliance obligations over time by allowing resources that come online through 2022 to generate five years of infinite-life RECs. Thus, Staff and ICNU's suggestion effectively requests the Commission to impose an arbitrary regulatory constraint on IRP portfolio design that is not consistent with applicable statutes and likely increases the costs associated with RPS compliance over time.

Senate Bills 838 and 1547 are important examples of energy policies that inherently require long-term planning in order to minimize costs and risks. Under the current Guidelines, the IRP process is well-suited to answer long-term planning questions regarding RPS obligations and in identifying the best near-term actions to meet these obligations over time.

### 3.2. Least-cost, least-risk planning

> ***The pursuit of near-term RPS procurement is consistent with the standards of least-cost, least-risk long-term planning.***

Within the constraints imposed by Oregon and federal energy policies, PGE is responsible for 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."[43] In an effort to identify a portfolio with the best combination of expected costs and associated risks, PGE explored a variety of RPS compliance strategies in its 2016 IRP. The Company tested resource procurement timing, size, and technology. PGE also explored additional strategies in its Reply Comments.[44] These analyses identified that, under all of the futures[45] explored within the 2016 IRP to quantify risk, near-term RPS procurement that captures the value of the PTC is lower cost than adopting a delayed or "just in time" RPS procurement strategy. In response to comments from stakeholders, PGE's Reply Comments provided additional analysis across an even broader set of potential risks by testing sensitivities with more rapidly declining technology costs; zero load growth; zero minimum REC bank; and a shorter net present value of revenue requirements (NPVRR) planning horizon. As RNW and NWEC note, this supplemental analysis further substantiated the findings in the IRP and addressed concerns identified by stakeholders in the first round of comments.[46]

Staff, however, remains unconvinced by the economic findings presented in the 2016 IRP and PGE's Reply Comments, because the $173 million NPVRR value associated with near-term RPS action represents "less than one percent of the preferred portfolio NPVRR."[47] This

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[43] IRP Guideline 1(c), Order No. 07-002, Appendix A at 28.
[44] *In re Portland General Electric Company's 2016 Integrated Resource Plan*, PGE's Reply Comments at 15-23 (Mar. 31, 2017).
[45] These futures explored risks related to: future gas prices and carbon prices (and the associated electricity prices), load levels, variable renewable output, technology capital costs, and hydro output.
[46] RNW at 1; NWEC at 5.
[47] Staff's Final Comments at 13.

characterization of the scale of the economic benefit is somewhat misleading because it compares the economics of new potential actions to a number that encompasses sunk costs associated with PGE's existing generation portfolio. The NPVRR[48] associated with RPS and Generic Capacity additions between 2018 and 2040 in the Delay Portfolio described in PGE's Reply Comments is $2,595 million. The $173 million savings associated with near-term RPS action therefore represents a 6.7% cost reduction relative to the cost of resource actions between 2018 and 2040 in the Delay Portfolio. Staff's implication that the cost savings is small relative to an increase in risk is also misleading. The standard deviation of the NPVRR across futures (the metric proposed by Staff to quantify variability) is $18.5 million lower for the portfolio with a 175 MWa RPS addition in 2020 than the Delay Portfolio, indicating that early RPS action is not riskier than delayed RPS action on the basis of quantifiable long-term risks.

PGE also notes that the IRP Guidelines do not specify a minimum NPVRR difference threshold to justify a proposed resource action and notes that Staff does not extend the same NPVRR threshold concern to other proposed resource actions, including energy efficiency and demand response.

Staff and ICNU point to additional risks or potential events as justifications for inaction on RPS. They speculate that various risks or events could bring about changes to the regulatory or economic landscape in which procured resources (renewable or otherwise) may operate. PGE has accounted for risks within the IRP. For example: Staff's concern regarding renewable production risk is addressed with both a low Variable Energy Resource (VER) output future and the minimum REC bank analysis; resource diversity,[49] is discussed in detail in Chapter 5 of the IRP and is not precluded by the Action Plan; and qualifying facility (QF) contract growth,[50] is evaluated in PGE's Reply Comments and will be updated prior to issuing a renewables RFP. PGE addresses Staff's concerns related to solar cost reductions[51] in Section 3.5 of these Final Comments.

Staff also speculates about ongoing developments that are largely unrelated or anticipated to have small impacts to RPS obligations or RPS economic considerations, including storage cost curves and Oregon's Community Solar program.[52] PGE is monitoring energy storage costs and took a proactive approach to evaluating energy storage in the 2016 IRP. While lower cost energy storage may produce opportunities for meeting future capacity needs and reducing renewable integration costs in future years, it would not dramatically impact the economics of RPS resources unless renewable integration costs were a significant driver of portfolio economics. Analysis demonstrated this was not the case in the 2016 IRP.[53] And, while the Community Solar program may spur the development of new solar projects, the size of this program is small relative to PGE's future RPS obligations.

And finally, Staff and ICNU raise concerns grounded in speculation about the continued evolution of the utility industry, the effects of which are unknown and/or unquantifiable in

[48] Including resource costs and energy value under Reference Case assumptions.
[49] Staff at 12.
[50] *Id* at 11.
[51] *Id.*
[52] *Id.*
[53] *See PGE's 2016 IRP* at 200.

advance. These include: distributed resource planning;[54] material changes to the RPS law;[55] the development of new unforeseen technologies[56]; and the fundamental restructuring of BPA[57]. Potential industry changes are not unique to this IRP. The industry will continue to evolve and long-term planning will need to proceed in the face of unquantifiable uncertainties. Consistent with the IRP Guidelines and Commission precedent, it is reasonable and prudent to continue to make planning decisions based on the best available information and to be ready to take advantage of additional opportunities to reduce costs in the future should such opportunities arise.

PGE also notes that there are unquantifiable risks that support the pursuit of near-term RPS action. Specifically, with regard to the risk of changes to RPS legislation, PGE believes that Oregon's legislative history, RPS trends in other states, and the recent resolutions adopted by the City of Portland and Multnomah County to meet 100% of electricity demand with clean and renewable resources by 2035[58] all suggest that the Company's clean and renewable obligations, relative to the current RPS legislation, are much more likely to increase than decrease in the future. Renewable obligations may also be greater over time than as modeled in the IRP should new loads arise due to the adoption of new low carbon technologies like electric vehicles. Under such circumstances, the procurement of low cost renewables in the near-term may reduce the risk of future rate volatility. Finally, delayed RPS procurement also increases the risk that high quality renewable sites will be unavailable due to development by other parties to meet ever-increasing renewable obligations, which could potentially raise compliance costs.

As described in Section 2.1, the IRP Guidelines establish a process by which utilities may determine reasonable near-term actions to address long-term needs under uncertainty. PGE has worked within this process to address the quantifiable risks identified by the Company and stakeholders in the public process as well as additional sensitivities requested from parties through data requests and filed comments. Throughout this process, PGE has shown that the proposed RPS actions are consistent with least-cost, least-risk planning.

### 3.3. RPS resource value

> ***In addition to RPS compliance value over time, the procurement of energy from physical renewable resources provides significant value to customers immediately upon incorporation into the portfolio.***

In focusing on the regulatory need for RPS resources, some parties fail to consider the non-REC value streams produced by incremental procurement from physical renewable resources. For example, ICNU claims that if PGE procures an RPS resource in the near term, then "[b]eginning in 2020, customers will pay for a resource whose sole purpose at that time will be to bank RECs for future customers."[59] NWEC, RNW, and Staff correctly point out that procurement of

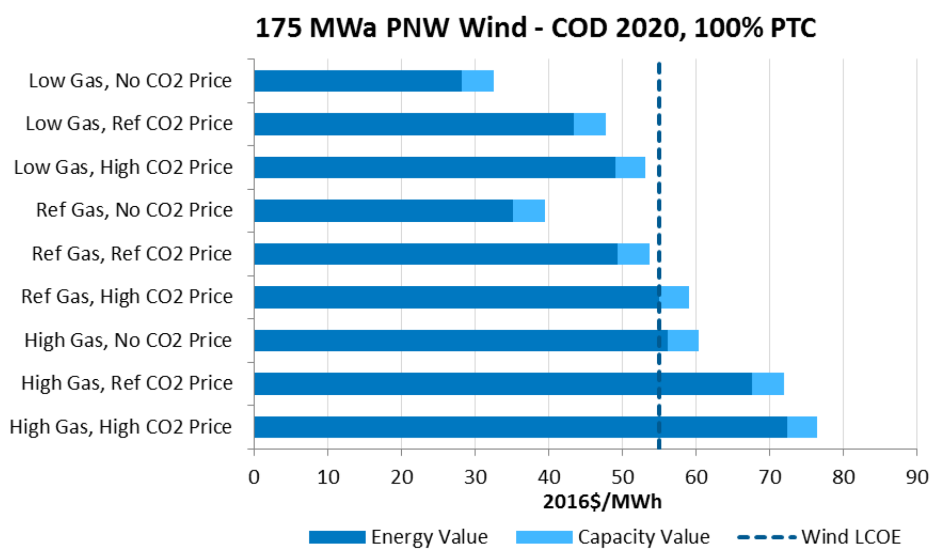
[54] Staff's Final Comments at 12.
[55] ICNU's Final Comments at 7.
[56] *Id*.
[57] *Id*.
[58] And 100% of economy-wide energy demand with clean and renewable resources by 2050.
[59] ICNU at 4.

physical RPS resources would contribute to meeting PGE's capacity needs.[60] Such resources would also provide energy value through avoided market purchases as well as avoided emissions benefits immediately upon becoming operational. All of these factors contribute to the quantitative determination made in the IRP analysis that near-term RPS procurement provides the best balance of cost and risk.

Benefits of physical RPS resources in addition to RECs (i.e., energy and capacity value) may be substantial relative to resource cost. **Figure 1** and **Figure 2** show the energy value and capacity value of 175 MWa RPS additions (PNW Wind and Tracking Solar PV) with a commercial online date (COD) of 2020 under various gas price and carbon price futures. PGE compares these value streams against the levelized cost of energy (LCOE) of wind and solar based on the resource cost assumptions in the 2016 IRP. Across all futures, the combined energy and capacity value of the resource is substantial relative to the cost, particularly for wind resources. In fact, in some futures, the value of wind may exceed the LCOE. An RFP for renewable resources may yield bids with both lower costs than those modeled in the IRP and/or greater energy and capacity benefits than were modeled in the IRP, for example solar with storage.

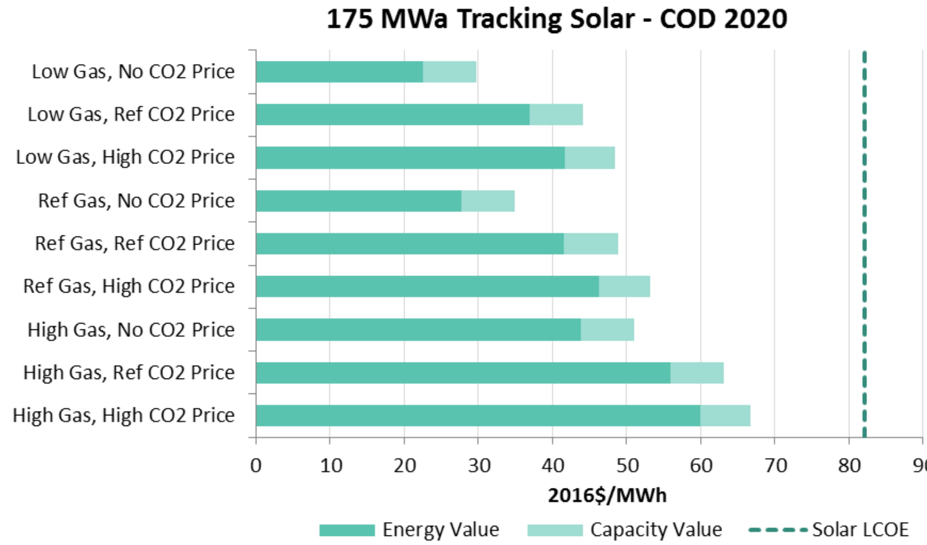
The discussion above indicates a potential for renewable resources procured through the Action Plan to provide significant benefits to customers before accounting for the additional value associated with their environmental attributes. Consistent with the Action Plan, a renewables RFP would allow PGE to meet a portion of its near-term energy and capacity needs with non-emitting resources and to generate RECs at low cost for RPS compliance in future years.

**FIGURE 1. LCOE AND VALUE FOR 175 MWA OF PNW WIND**




[60] NWEC at 6; RNW at 6; Staff at 7.

**FIGURE 2. LCOE AND VALUE FOR 175 MWA OF TRACKING SOLAR PV**




### 3.4. Intergenerational equity

***IRP Guideline 1 establishes the methodology for weighing potential costs and benefits over time.***

Staff, ICNU, and CUB challenge the economic merits of near-term RPS procurement on the basis of intergenerational equity arguments, arguing that today's customers would pay for resources that PGE will use to serve customers in the future.[61] This logic is inaccurate for a number of reasons.

The IRP guidelines provide clear guidance regarding the treatment of costs and benefits over time and the associated potential for issues of intergeneration equity. IRP Guideline 1 requires that PGE consider the NPVRR at least 20 years into the future when evaluating the cost implications of various portfolios.[62] Embedded within the NPVRR calculation is a discount rate that weighs the importance of costs and benefits experienced in the near-term versus the costs and benefits experienced in future years. A large discount rate in the NPVRR calculation would tend to favor making decisions that are lower cost in the near-term and potentially more costly in the future. As the discount rate approaches zero, the NPVRR increasingly reflects the costs and benefits in future years. IRP Guideline 1(a) requires that PGE use the after-tax marginal weighted-average cost of capital (WACC) to discount future costs.[63] PGE agrees that both short- and long-term economic considerations are important in any long-term planning exercise. However, the Company suggests that the IRP Guidelines already outline an industry standard approach to weighing these intergenerational economic considerations.

[61] Staff at 14; ICNU at 2; CUB at 6.
[62] Order No. 07-002, Appendix A at 1 (as corrected by Order No. 07-047).
[63] Order No. 07-002, Appendix A at 1 (as corrected by Order No. 07-047).

Furthermore, as described in Section 3.3, if PGE procures RPS resources in the near-term, customers will receive energy value, through avoided market purchases, and capacity value, through avoided procurement of capacity resources, when the resources come online.

Lastly, while Staff and CUB express concern regarding the weighting of economic considerations over time, PGE heard clear feedback at the May 15th OPUC public meeting that customers are also concerned about the impacts of externalities over time, especially environmental externalities. At the meeting, dozens of customers expressed an interest in more rapid renewable development in the near-term in order to produce environmental benefits and reduce compliance costs for both current and future generations. PGE incorporated such environmental concerns into the IRP analysis through the cost and risk metrics by imposing a carbon price over time in the Reference Case ($39/ton real-levelized) and by exploring multiple carbon price futures in the risk analysis ($0/ton and $60/ton real-levelized). PGE appreciates the engagement of the public on this topic and looks forward to continued discussion around the incorporation of environmental considerations within the IRP planning process. In the meantime, near-term RPS procurement is consistent with PGE's least-cost, least-risk planning process and has broad support from stakeholder groups and customers on the merits of its economic and environmental benefits. The Company firmly believes that it should not miss this opportunity to provide clean and affordable energy to its customers.

### 3.5. Resource prices and forecasts

> ***The near-term low price environment cited by Staff is not indicative of long-term price trends and instead represents a near-term opportunity to reduce RPS compliance costs to customers.***

Staff expressed concern regarding the potential for future solar cost reductions to erode the value of near-term RPS action. In particular, Staff points to a Solar Energy Industries Association (SEIA) report[64] as an indication of current solar prices, and speculates that recent short-term price trends signal future long-term technology cost reductions. PGE notes that the same industry report cited by Staff describes the near-term market forces that have led to such a low solar price environment:

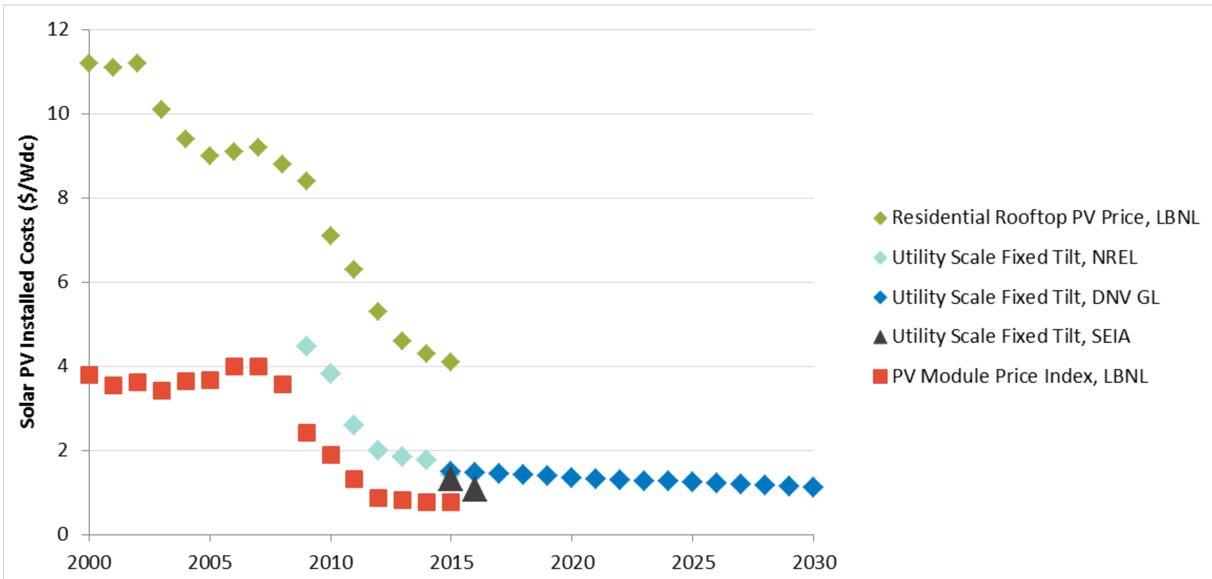
> *The dramatic decline in component prices in the second half of 2016 was driven by excessive component supply versus quarterly demand. This caused suppliers to aggressively slash prices and prompted buyers to adopt 'wait-and-see' strategies, which allowed prices to decline further.*[65]

While technological and manufacturing process improvements drive long-term cost reductions, the SEIA report suggests that transient, short-run market factors, like supply-demand imbalance, are driving recent PV price trends. The long-term renewable resource cost projections provided by DNV GL, and utilized in the 2016 IRP, represent long-run equilibrium pricing impacted by fundamental improvements in technology and manufacturing processes. These forecasts are not

[64] Solar Energy Industries Association. "Solar Market Insight Report 2016 Year in Review." http://www.seia.org/research-resources/solar-market-insight-report-2016-year-review (accessed on June 19, 2017).
[65] *Id.* http://www.seia.org/research-resources/solar-market-insight-report-2016-year-review.

intended to capture the transient market effects that have driven solar prices in recent years, in part, because there is no theoretical basis for assuming that the phenomena that have driven these price fluctuations will persist into the future. These phenomena also have the potential to reverse, leading to periods of higher prices. In fact, the possibility of future increases in U.S. solar prices was recently discussed in the context of an ongoing investigation by the U.S. International Trade Commission into solar panel imports.[66]

**FIGURE 3. HISTORICAL AND FORECAST SOLAR PRICES.**




Investigation of historical PV module pricing indicates that the industry has been marked by periods of both module price increases and decreases. **Figure 3** shows that, according to researchers at Lawrence Berkeley National Laboratory (LBNL), PV module prices (red squares) were relatively flat or increasing between 2000 and 2007 before decreasing from 2007 to 2011 and leveling out between 2011 and 2015.[67] Historical system prices (light blue diamonds) cited by the National Renewable Energy Laboratory (NREL) reflect a similar trend in which price reductions slowed between 2009 and 2015. The price data cited by Staff[68] (dark grey triangles) reflect aggressive year-on-year price reductions that are not indicative of these long-term trends. In fact, the PV system prices cited by Staff are so low that they approach the PV module price index, indicating either near-zero non-module costs or prices that are artificially low due to market conditions like the price slashing behavior described by SEIA. The Company considers it highly speculative to claim future benefit for customers based on projections that extrapolate this near term trend and significantly deviate from long-term expert forecasts.

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[66] "ITC ruling is a clear and present threat to US renewables." *Financial Times*, https://www.ft.com/content/430fea5a-4922-11e7-919a-1e14ce4af89b. Accessed June 5, 2017.
[67] Barbose, Galen and Naïm Darghouth. 2016. "Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States." Berkley, CA, Lawrence Berkeley National Laboratory. https://emp.lbl.gov/publications/tracking-sun-ix-installed-price. Accessed June 19, 2017.
[68] "Solar Market Insight Report 2016 Year in Review," Solar Energy Industries Association. http://www.seia.org/research-resources/solar-market-insight-report-2016-year-review. Accessed June 19, 2017.

PGE appreciates that market intelligence suggests a low price environment in the near-term for solar resources and notes that market data also suggests a potentially favorable environment for procuring low cost wind resources as the industry pushes for development prior to PTC expiration.[69] This low price environment provides additional opportunity to capture net benefits for customers by allowing solar and wind resources to compete in an RFP in the near term.

### 3.6. Wind repowering

> ***Wind repowering results in greater net customer costs relative to new RPS resource procurement due to limited opportunities for substantial energy and capacity value.***

In Final Reply Comments, Staff asserts that "PGE failed in its IRP analysis to examine other actions that also maximize PTC benefits. Specifically, PGE did not perform a wind repowering analysis, and did not examine the early RPS wind acquisition size scenarios that PGE's models determined were lowest cost."[70]

PGE believes Staff is misinterpreting the Company's goals to fill capacity needs and meet RPS requirements in a least-cost, least-risk manner (including the utilization of tax benefits to reduce customer costs) as purely a desire to maximize PTCs. As to Staff's second concern regarding RPS wind acquisition size, the Company thoroughly discussed this issue in Section 3.2 of PGE's Reply Comments of March 31, 2017.

PGE acknowledges that the wording used in the IRP action plan of "a preference for maximizing available incentives for the benefit of customers"[71] was simplified and did not encompass the complexity of the analysis leading to the conclusion to recommend issuing an RFP for renewable resources. In PGE's Reply Comments, PGE clarified that the recommendation for early action on RPS is based on the full NPVRR benefits of early action, which, in addition to including the benefits of PTCs and RECs, also include the benefits of energy and capacity. PGE did not recommend early action based solely on the objective of maximizing available incentives. Additional discussion of RPS resource value is included in Section 3.3 of these comments.

Staff has sought to understand the economics of repowering relative to RPS Early Action.[72] While PGE has not prepared a full NPVRR study, **Table 1** compares a number of key metrics regarding repowering of PGE's Biglow Canyon Wind Farm (Biglow) compared to a 100% PTC compliance 175 MWa PNW wind resource.[73] The estimates for the repowering scenario examine improvements to annual energy production (AEP) of 0%, 10%, and 30%. While PGE has not conducted a wind resource assessment using repowered assumptions and a 30% increase in

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[69] According to Windpower Monthly, wind developers "stockpil[ed] enough components to build 30-70GW of new capacity" by the end of 2016 in order to secure PTCs. Source: "Investors fear 'Trump effect' on global wind energy costs," March 1, 2017. http://www.windpowermonthly.com/article/1425155/investors-fear-trump-effect-global-wind-energy-costs. Accessed June 19, 2017.

[70] Staff's Final Comments at 12.

[71] *See*, PGE's 2016 IRP, Section 13.2.

[72] *In re Portland General Electric Company's 2016 Integrated Resource Plan*, OPUC Data Request No. 122.

[73] The Biglow repowering scenario examines repowering of all three phases of the Biglow Canyon Wind Farm with the assumption of a repowered date of January 1, 2020 and 80% PTC compliance. The 175 MWa PNW wind resource is assumed in service on January 1, 2020.

annual energy production may not be achievable at Biglow, it is included in the table below for comparison.

**TABLE 1. Comparison of Early Action to Biglow Repowering**

| | Early Action | Biglow Repower | Repower AEP Increase |
|---|---|---|---|
| **Additional Annual Energy / RECs** | 175 MWa | 0 MWa<br>13 MWa<br>40 MWa | 0%<br>10%<br>30% |
| **Avoided Annual $CO_2$** | 692k tons | 0 tons<br>53k tons<br>160k tons | 0%<br>10%<br>30% |
| **Capacity Contribution** | 59 MW | 0 MW<br>4 MW<br>15 MW | 0%<br>10%<br>30% |
| **Energy Revenue NPV**[1] | $1,399M | $0<br>$101M<br>$304M | 0%<br>10%<br>30% |
| **Avoided Capacity Savings NPV**[2] | $126M | $0M<br>$8M<br>$32M | 0%<br>10%<br>30% |
| **Capital Requirement**[3] | $858M | $422M<br>$422M<br>$422M | 0%<br>10%<br>30% |
| **PTC NPV**[4] | $488M | $292M<br>$322M<br>$382M | 0%<br>10%<br>30% |

1. Net present value of incremental energy revenues in 2017$, reference case future.
2. Net present value of avoided generic capacity cost (COD 2020) in 2017$, reference case future.
3. 2017$. Overnight capital expenditures for a COD of January 1, 2020. RPS Early Action costs are based on the DNV GL report in Appendix M of the 2016 IRP. The turbine costs from the same report provide the basis for the estimated equipment cost for repowering. The costs were reduced to exclude assumed tower expenses. Estimated costs for equipment removal and installation were included.
4. Net present value of incremental PTCs in 2017$.

Repowering would require a significant rate base investment relative to the magnitude of its contributions to meeting the capacity and REC needs identified in PGE's 2016 IRP. Additionally, compared to RPS Early Action, an investment in repowering brings little additional energy and a correspondingly smaller reduction to carbon emissions.

In considering a Biglow repowering scenario, it is important to note that PGE would remove existing equipment that has roughly ten years of service, and likely little, if any, salvage value. The Company would need to recover the remaining undepreciated cost. At the end of 2016, the total remaining undepreciated cost for Biglow Canyon was approximately $450M.

PGE does not recommend that RPS actions be decided purely on the basis of maximizing PTCs in isolation of other considerations. PGE does not find repowering to be a compelling alternative to Early Action.

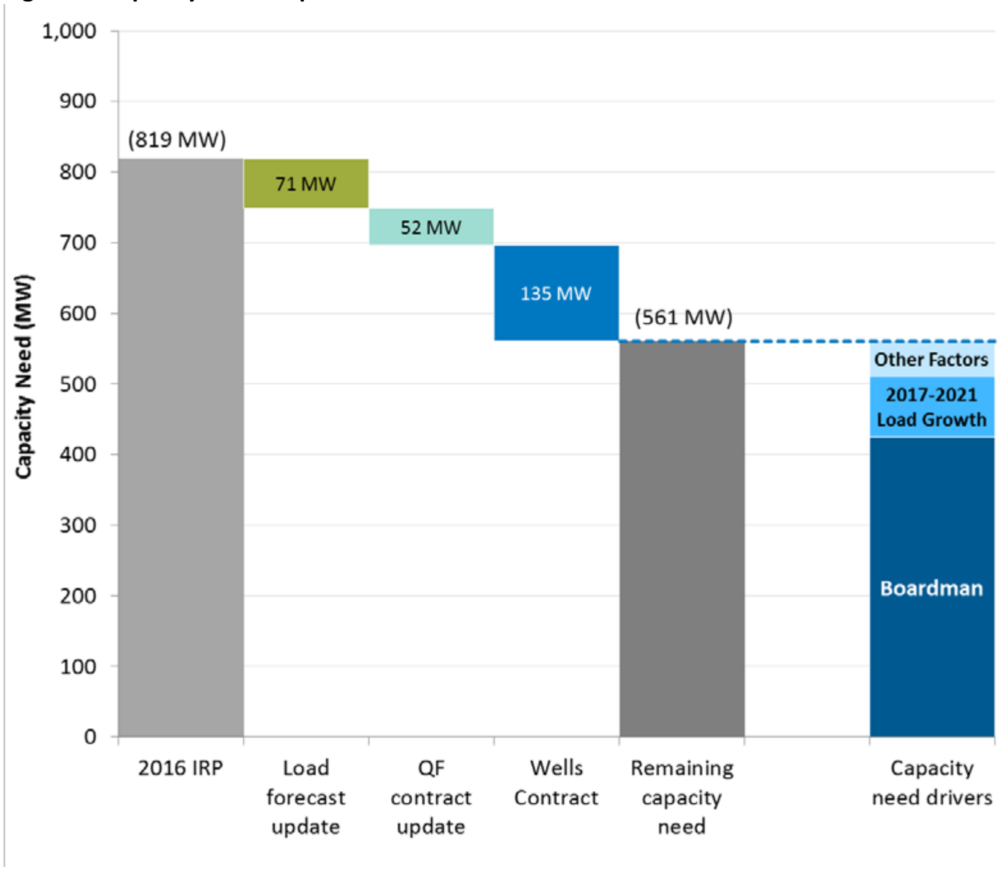
# 4. Capacity Actions

## 4.1. Capacity Need Update

***As in previous IRP/RFP cycles, PGE continues to provide updated assessments of capacity need.***

PGE provided an updated assessment of its capacity need on April 13, 2017, to incorporate the recently executed renewal contract with Douglas County for a portion of the Wells Hydro Facility.[74] The update also included PGE's December 2016 Load Forecast and QF contracts executed through December 2016. PGE's remaining capacity need is 561 MW after these updates, as shown in **Figure 4** below. As discussed in the IRP, the remaining need is after accounting for planned acquisitions for cost-effective energy efficiency, demand response, and dispatchable standby generation.

**Figure 4. Capacity Need Impact due to Load and Contracts**




PGE clearly indicated that the updates decrease the quantity of capacity needed to achieve resource adequacy; however, PGE notes that in Final Comments, ICNU mischaracterizes PGE's updated need as a request for "upwards of 950 MW".[75] PGE assumes that ICNU has

[74] PGE Update to Figure 5 of PGE Reply Comments, filed April 13, 2017.
[75] Mullins (on behalf of ICNU) at 3.

misinterpreted Table 1 from PGE's Reply Comments, Section 4.2.9 of PGE's Reply Comments, PGE's Update Letter from April 13, and the wording of the 2016 IRP, which recommended "up to 850 MW".

As indicated in PGE's Reply Comments, PGE will provide the Commission with an update on the amount of capacity that it needs to procure before issuing an RFP for capacity.[76]

## 4.2. Capacity Assessment Methodology

***The IRP is based on sound capacity adequacy modeling.***

The methodology for assessing capacity adequacy presented in the 2016 IRP and discussed in Section 4.2 of PGE's Reply Comments is robust, sophisticated, and transparent. It results in a prudent assessment of resources needed to achieve the Company's resource adequacy metric - loss of load expectation of 1-day-in-10-years.

PGE extensively discussed the capacity assessment methodology during the public process as well as in Section 5.1 of the IRP.[77] The capacity assessment methodology is based on an open source model, RECAP, which PGE provided to parties, along with input and output files. The methodology brought several improvements to PGE's process, as discussed in Section 4.2.1 of PGE's Reply Comments.[78] One key item is the application of a single model to assess renewable capacity contribution and capacity need. This improves the usefulness of the results and allows PGE to comply with OPUC Order No. 16-326. Stakeholders and Staff have provided positive feedback on the methodology. 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."[79]

While transparent, the modeling is complex and one stakeholder party, ICNU, misinterprets and misrepresents the modeling and results in its Final Comments.[80] ICNU's concerns are identical to those presented in its Opening Comments. PGE continues to object to ICNU's inaccurate mischaracterizations and refers the Commission to its response in Section 4.2 of the Company's Reply Comments, most notably in *Section 4.2.3 Planning Reserve Margin* and *Section 4.2.8 Staff and ICNU Assessments*.

PGE continues to be willing to work collaboratively with all parties to enhance understanding of the reliability modeling.

[76] PGE's March 31, 2017 Reply Comments at 12.
[77] PGE discussed the capacity assessment modeling at the following public meetings: August 13, 2015, December 17, 2015, and May 15, 2016.
[78] *See* PGE's March 31, 2017, Reply Comments, Section 4.2.1.
[79] Staff's Opening Comments at 21.
[80] Mullins at 4-6.

### 4.3. Spot Market Assumptions[81]

***PGE includes reasonable assumptions for spot market access for long-term resource adequacy planning.***

PGE's capacity adequacy modeling included the assumption of 200 MW of access to market power during constrained conditions excluding summer on-peak hours. This assumption is in alignment with PGE's 2013 IRP and PGE presented this information during the public meeting process. The assumption of no access to market power during summer on-peak hours is similar to the summer import constraints in the Northwest Power and Conservation Council's (Power Council) regional adequacy assessment for 2021.[82]

In Final Comments, ICNU states that PGE's assessment that it can rely on the market only for up to 200 MW is out of synch with the fact that it relied on the market for over 33% of its retail load needs just four years ago.[83] This is a false comparison and suggests a potential misunderstanding of capacity and average energy. As noted in Section 4.3.2 of PGE's March 31, 2017 Reply Comments, this comparison improperly equates the spot market assumption under constrained conditions used in capacity adequacy modeling of future years to the percentage of 2013 annual energy (MWa) served by purchased energy of varying timing (both within the day and season) and varying term (including spot, short, and mid). The comparison makes no sense. The energy purchases for 2013 do not provide a useful estimate of the quantity of excess capacity that will be available in 2021 for firm delivery to PGE's balancing authority under constrained conditions, such as during regional cold snaps or heat waves.

Including any amount of access to spot market as an assumption in a capacity adequacy model is not without risks. There is no obligation on the part of others to commit resources in a spot market, nor is it reasonable to assume that the costs would be equivalent to wholesale energy prices under average conditions. Excessive presumptions of access to the spot market can lead to market failure and high costs, as discussed in **Section 4.4** of these comments.

While PGE has appropriately not assumed an increase in the quantity of spot market included in the capacity adequacy modeling, PGE acknowledges that its potential exposure to reliance on the spot market has increased due to increased customer enrollment with Electric Service Suppliers (ESS).[84] The Company also notes that the risks associated with spot market exposure may increase over the next few years as a substantial quantity of regional and WECC capacity is retired.

Finally, PGE reiterates that the treatment of exposure to the spot market in the <u>resource adequacy evaluation</u> is different from the unrestricted access to the wholesale market for economic energy

[81] Spot market availability is, as noted in PGE's Reply Comments, not the same as executing contracts for rights to capacity on a long, mid, or even short-term basis, with determined obligations and costs. Issues related to the ability to assess the viability of meeting capacity needs in a least-cost, least-risk manner through contracts executed for existing resources are discussed in **Section 5** of these Comments.
[82] *See* PGE's March 31, 2017, Reply Comments, Section 4.3.2.
[83] ICNU at 17.
[84] *See*, PGE's 2016 IRP, Section 4.1.6.

purchases and sales in the economic evaluation. Sections 4.3.1 of the Company's Reply Comments discusses market access in the economic evaluation.

### 4.4. Free Ridership

***Reliance on resource actions that promote free ridership can lead to increased risk and market failure.***

Some stakeholders have expressed a desire for PGE to increase assumptions of spot market availability,[85] equate firm power purchases with financial transaction,[86] and presume short-term acquisitions are available with little to no fixed costs.[87] Stakeholders are advocating for a form of "free ridership," which occurs when benefits from the use of a resource are taken advantage of by entities that have not paid for it. This can lead to resource shortages and, potentially, market failures.

Resources that are available at a discount and can be secured for customer use may bring substantial cost savings; however, history has shown that it can be costly and risky to presume substantial quantities will be available under constrained conditions. The energy crisis of 2000 and 2001 was proceeded by a period in which some parties determined that costs could be reduced by maintaining substantial open capacity positions – relying on the wholesale energy market to provide large quantities of power under constrained regional conditions instead of entering into long-term PPAs or ownership to provide the necessary mechanisms to recover fixed costs for new resources. This contributed to the crisis which brought both extreme pricing and load curtailment.

Professor Paul L. Joskow of the Massachusetts Institute of Technology found that free ridership philosophies were present leading up to the energy crisis:

> *"The assumption was that wholesale power prices would be significantly below the prevailing price of generation service reflected in regulate [sic] retail rates; after all, the primary motivation for the reforms was the prospect of consumers getting access to the "cheap power" expected to be available in wholesale markets. Nobody broached the possibility that wholesale prices could possibly be higher than the regulated price of generation service reflected in prevailing retail prices. The entire rationale for the reforms was that wholesale prices would be lower than the regulated retail price of generation service."*[88]

[85] ICNU at 17.
[86] PGE strongly disagrees with ICNU's statement that, "[a]s the Company acknowledges, an FOT [front office transaction] is a planning construct representing firm power purchases, including physical or financial power products." Mullins at 6 (emphasis added). Many FOTs are non-firm, recallable physical power purchases. Financial products are purely monetary transactions.
[87] CUB Opening Comments at 7.
[88] Paul Joskow. (2001). *California's Electricity Crisis*, p. 10. https://www.hks.harvard.edu/hepg/Papers/CALIF.%20-%20Joskow%209-01-UPDATE.pdf. Accessed May 23, 2017.

The desire to access “cheap power” lead to regulatory changes, which removed the ability to enter into long-term contracts:

> *“Shortcomings of the wholesale electric market rules established under the State's restructuring plan contributed to the increase in wholesale prices. Specifically, under the market rules, PG&E, SCE, and SDG&E were required to buy all of their power through the CalPX. They could not enter into forward long-term contracts for energy. When spot market wholesale prices increased because of power shortages and increasing generation costs, the utilities had no option but to purchase the high-priced power.”*[89]

As noted in *The California Electricity Crisis: Causes and Policy Options*, “excessive reliance on the spot market” contributed to the energy crisis:

> *“The shortages in generating capacity played a critical role, increasing the bargaining strength of merchant generators and signaling the enormous profits that could be gained through supply shortages. At the same time, the excessive reliance on the spot market increased the opportunities and incentives for generators to increase their prices well above the costs of generating power. Third, California relied far too much on the spot market for wholesale power instead of securing power through more stable long-term contracts. This choice exposed the utilities to exceptional risks, producing a full-blown financial fiasco.”*[90]

Some stakeholders point to the short capacity positions taken by other Pacific Northwest utilities in the past as justification for recommending a larger spot market capacity assumption for PGE’s long-term planning today.[91] These suggestions are made despite announcements of significant capacity retirements in the near future[92] and despite the recent lessons learned from the energy crisis. The fact that utilities in this region often experience similar peaking hours and are subject to the similar hydro, wind, and solar conditions, suggests individual utility reliance on the spot market to meet capacity obligations should, if anything, be reduced in this environment.

PGE’s IRP proposes to meet customers’ capacity needs by acquiring resources through bilateral negotiations and, if needed, an RFP process[93], while maintaining a prudent exposure to the spot market. This approach provides the opportunity to capture reduced costs for existing resources if

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[89] US Energy Information Administration. *Subsequent Events- California’s Energy Crisis*. https://www.eia.gov/electricity/policies/legislation/california/subsequentevents.html. Accessed May 23, 2017.

[90] Christopher Weare. 2003. *The California Electricity Crisis: Causes and Policy Options*, page iv. http://www.ppic.org/main/publication.asp?i=374. Accessed May 17, 2017.

[91] Mullins at 8.

[92] See Northwest Power and Conservation Council, *7th Power Plan*, “Existing Resources and Retirements.” February 10, 2016. Accessed June 19, 2017: https://www.nwcouncil.org/media/7149929/7thplanfinal_chap09_existresources.pdf; *see also* Puget Sound Energy, *Colstrip Owners Settle Lawsuit in Montana*, July 12, 2016. Accessed June 21, 2017: https://pse.com/aboutpse/PseNewsroom/NewsReleases/Pages/Colstrip-Owners-Settle-Lawsuit-in-Montana.aspx; and California Energy Commission, *Once-Through Cooling Phase-Out*, Last updated 3/8/2017. Accessed June 21, 2017: http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf.

[93] See **Section 5.1** of these comments for additional discussion of capacity procurement.

available and to reduce the risks historically associated with proposals that are based on free-ridership concerns.

### 4.5. Dispatchable capacity need

> ***PGE is committed to promptly updating its dispatchable capacity need.***

Staff states that it will "look to the Company to inform Staff on the best course of action to determine its 2021 flexible capacity needs in its Final Comments, given the changes in its resource stack."[94] PGE appreciates this opportunity to provide clarity around the impact of recent and potential future actions on the Company's dispatchable capacity need. Within the Action Plan, PGE considers any resources that are consistent with the description of dispatchable capacity in the IRP to contribute to meeting the annual dispatchable capacity need. This language reads:

> "… a qualifying dispatchable resource may have operational capabilities similar to a combined cycle, frame combustion turbine, or reciprocating engine to meet this requirement. 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. Very high variable cost or call-limited resources that cannot be called within an hour do not provide adequate dispatchability to meet this requirement."[95]

Accordingly, after the execution of the Wells hydro contract, PGE updated its remaining dispatchable capacity need in 2021 from 375-550 MW to 240-415 MW due to the capacity contribution of the Wells hydro contract in that year – 135 MW. PGE has estimated such reduced dispatchable capacity need using its RECAP model. If bilateral negotiations result in additional dispatchable capacity, PGE will update the remaining annual dispatchable capacity need and will include this update in the report to the Commission.

## 5. Resource Acquisition

> ***PGE is actively engaged in bilateral negotiations for existing capacity but continues to request acknowledgement of a capacity RFP should it be unable to obtain sufficient capacity to meet customer needs***

All parties recommend modifications to PGE's proposed acquisition strategy to issue one or more Requests for Proposals for Major Resources. Despite the requirements of the OPUC Competitive Bidding Guidelines,[96] many parties, including Staff, CUB, NIPPC, ICNU and Sierra Club, suggest that any acquisition strategy should prioritize, or in some cases be constrained to, term-limited resources. Staff recommends against pursuing an open RFP to acquire capacity or

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[94] Staff's Final Comments at 32.
[95] *PGE's 2016 IRP* at 146.
[96] Order 14-149, Appendix A, Guideline 1.

renewable resources. NWEC and RNW recommend PGE pursue an RFP for renewable resources.[97] Parties' recommendations are not consistent with the Commission's IRP and RFP Guidelines and are not in the best interest of customers.

### 5.1. Capacity Procurement

Staff, CUB, NWEC, ODOE, and RNW recommend PGE pursue bilateral negotiations to secure existing capacity resources, especially hydroelectric generation, ahead of a capacity RFP.[98] As indicated in PGE's Reply Comments, based on feedback from the Commission, Staff, and stakeholders, PGE is pursuing bilateral negotiations for acquisition of capacity from existing resources in the region.[99] PGE has identified several counterparties with existing capacity resources that they might be willing to make available to PGE. PGE is currently attempting to negotiate term sheets with these counterparties. The terms of any transaction will be contingent on obtaining all necessary regulatory approvals for the transaction. If PGE is able to successfully negotiate term sheets, it will then seek approval from the Commission for waiver of the Competitive Bidding Guidelines so that it can complete the transactions outside of an RFP.

To promote the selection of least-cost, least-risk resources, the Company intends to evaluate all bilateral resources against each other and against the estimated cost of new long-term generating resources. Evaluating diverse, existing resources against new generating resources will help PGE ensure its recommended acquisitions are least-cost, least-risk, and will provide a useful comparison against the resources that the Company could reasonably expect to participate in an open solicitation.

At this time, it is not clear whether PGE will be able to execute term sheets for enough cost-effective capacity to meet the Company's identified capacity needs. Neither can PGE predetermine the result of any waiver filing with the Commission. For these reasons, PGE continues to request that the Commission acknowledge the issuance of an RFP for capacity resources. This would allow PGE to expeditiously file a proposed capacity RFP for Commission and stakeholder review should the Company not be able to obtain sufficient capacity through the bilateral negotiation process to meet its identified need. If PGE is able to obtain sufficient capacity through bilateral negotiations, then PGE would inform the Commission and not move forward with the RFP.

### 5.2. RPS Procurement

> ***An RFP for renewable resources should not be delayed until completion of bilateral negotiations for capacity.***

Staff suggests that PGE consider procurement of RPS resources as capacity products within an RFP for term-limited capacity resources.[100] PGE has two concerns with this approach:

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[97] NWEC at 15; RNW at 7.

[98] Staff at 18, Cub at 2, NWEC at 1, ODOE at 7, RNW at 14.

[99] PGE Reply Comments at 11.

[100] Staff's Final Comments at 39.

1. **Timing –** Given the time-limited nature of the PTC, the timeline of an RFP for renewable resources, and the development schedule for new resources, it is important to initiate an RFP for RPS resources as early as possible after an IRP Acknowledgement Order. Delaying RPS procurement activities until the time-uncertain conclusion of bilateral negotiations, and possibly the conclusion of Commission waiver proceedings, jeopardizes PGE's ability to move quickly enough to acquire the full benefits of the PTC and the associated savings for customers.

2. **Adequate treatment of REC value –** RPS resources bring value to customers through avoided market purchases (energy value), avoided capacity procurement (capacity value), and the ability to contribute to RPS compliance (REC value). PGE must consider each of these value streams in determining the portfolio of resources that provides the best combination of costs and risks for customers and the Company. Staff suggests "a renewable resource RFP could be justified by the capacity need if renewable resources were demonstrated as the least-cost, least-risk long-term option for capacity for ratepayers,"[101] but it is unclear if Staff recognizes other values associated with renewable resources. If RPS resources compete with non-RPS resources in an RFP, it is imperative that PGE recognize the REC value provided by those resources to ensure full accounting of resource costs and benefits.

PGE maintains that a near-term RFP for renewable resources is necessary to ensure that PGE can acquire low cost renewables to meet the system's energy, capacity, and RPS needs over time. Such an RFP is consistent with least-cost, least-risk planning analysis and PGE's IRP Action Plan. Because of the timing concern described above, PGE seeks to conduct an RFP for renewable resources as soon as possible after the Commission issues an order on PGE's 2016 IRP and prior to the conclusion of its bilateral negotiations and subsequent waiver processes.[102] PGE is concerned that a combined capacity and renewable RFP could not occur on a timeline that allows it to capture the value of the 100% PTC and in a manner that allows PGE to account for the REC value of RPS resources over time.

## 5.3. Term-limited resources

### 5.3.1. *Least-cost, least-risk procurement*

***A term-limited resource RFP would reduce competition and jeopardize least-cost, least-risk procurement.***

Parties, including CUB, NIPPC, and RNW, suggest that PGE's resource acquisitions are improperly driven to maximize shareholder returns.[103] This is not the case. The suggestions appear to rely solely on perceived financial incentives without recognizing the financial

[101] Staff's Final Comments at 16.
[102] Prior to commencing a renewables RFP, PGE will provide an updated analysis of the value of near-term RPS action based on the most recently incorporated load forecast, REC bank balance, executed QF contracts, and gas price forecast.
[103] CUB at 5; RNW at 2; and NIPPC's Final Comments.

disincentives related to imprudence and disallowances. PGE is committed to identifying least-cost, least-risk resource strategies within the transparent and robust IRP review process and to acquiring such resources through related Commission reviewed and approved procurement activities.

In order to determine whether a resource is least-cost, least-risk, it must be compared to other alternatives. The more resources that PGE is able to evaluate for procurement, the more likely it is to identify and acquire the lowest cost and risk resource. For this reason, PGE prefers to acquire major resources through an open competitive solicitation process that maximizes the number of resources offered to meet PGE's identified need.

Historically, the Commission has required PGE to maximize competition within its competitive bidding processes. In PGE's 2012 RFP, the Commission recommended that PGE make available its development sites for third-party bids. The Commission also recommended that PGE combine its capacity and energy RFP into a single solicitation to diminish the constraints that would limit bidder participation in the RFP.[104] Ultimately, these decisions were intended to increase competition in order to promote the selection of least-cost, least-risk resources for the benefit of customers. Indeed, one of the Commission's stated priorities is to "[p]romote price and service competition, where appropriate, so that utilities and their customers can shop for the cheapest supplies and get services tailored to their needs."[105]

Staff and CUB suggest introducing constraints to the competitive acquisition process. They recommend the Commission require PGE issue an RFP for 'term-limited' capacity resources.[106] Both Staff and CUB define term-limited resources as resources with a duration of less than fifteen years. This would constrain resource acquisition to a subset of comparable resources, based on owner, term, or counterparty and reduce competition.

Term-limited resource requirements place inappropriate limitations on resource ownership. While neither Staff nor CUB specifically define term-limited on the basis of asset ownership, NIPPC makes the ownership implications of such an RFP explicit: "NIPPC agrees with Citizen's Utility Board of Oregon and others that now is the time to "rent" (contract with) thermal resources rather than encumber ratepayers with new, costly and risk-laden utility owned generation." The Commission has found that mechanisms which would require a utility to purchase only from IPPs, regardless of impact on customer rates, are contrary to the goals underlying the IRP process.[107]

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[104] *In re Request for Proposals for Capacity Resources* Order No. 11-371 at 2 (Sep. 27, 2011).
[105] "Electric & Natural Gas." *Oregon Public Utility Commission*, http://www.puc.state.or.us/Pages/electric_gas/index.aspx. Accessed June 21, 2017.
[106] Staff at 20; CUB at 7.
[107] Order No. 14-149 at 16.

#### 5.3.2. ***Risks associated with short-term contracts***

***Term-limited resources are not riskless.***

Parties, including Staff, CUB, and NIPPC suggest that short-term contracts carry associated value related to 'optionality.' As PGE stated in its Reply Comments, the value of a shorter-term contract cannot be quantified without knowing how the contract's cost compares to the fully allocated cost of a long-term contract or investment; a fact that Staff acknowledges.[108] Nonetheless, parties continue to contend that shorter-term contracts provide inherent value as they allow customers to benefit from technological change accompanying this period of significant change.[109] These arguments ignore the potential costs related to short-term contracts and rely on speculation that future resource cost and risk characteristics will be favorable relative to resources available today.

In PGE's view, optionality is best delivered by resources and contracts that provide PGE with an option to extend the contract at a price certain. Option contracts lock in prices today and provide PGE with a future decision ('optionality') to either continue with a low-cost contract relative to a more expensive future market or to terminate and take advantage of a relatively less expensive future market. Term-limited contracts do not provide this optionality. Instead, they create obligations to renew or replace purchases more quickly in the future at terms that are uncertain today. In this regard, entering into a term-limited contract is not a riskless option. Rather, it is dependent on speculation that when the contract expires resources will be available and more affordable. The parties have presented no evidence to support this position.

Moreover, even if a short-term contract could be shown to be less expensive on a levelized basis than a long-term contract or investment, customers will only benefit in a lower price environment for replacement resources. While PGE forecasts capital cost declines for all major resources types, these declines occur parallel with forecasts of sharply increasing wholesale power prices. Furthermore, tightening regional supply of capacity, forecasted by the Northwest Power and Conservation Council (NWPCC), should otherwise increase regional pricing for replacement resources.[110]

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[108] "Staff does not believe this argument is entirely without merit." Staff's Final Comments at 19.
[109] Staff's Final Comments at 4.
[110] NWPCC, "Pacific Northwest Power Supply Adequacy Assessment for 2021," September 27, 2016. Accessed June 20, 2017: https://www.nwcouncil.org/media/7150591/2016-10.pdf.

### 5.4. Staff's Proposed Conditions to Precede Capacity RFP

#### 5.4.1. *Market study*

***The RFP process provides the best assessment of "market capacity" availability.***

Multiple parties expressed an interest in better understanding the availability of "market capacity" and recommended that a market study be completed prior to issuing an RFP.[111]

PGE interprets "market capacity" to refer to existing resources that the Company could secure to deliver firm capacity to PGE's Balancing Authority through short, mid, or long-term agreements.

Assessing availability of existing resources is complex and one of the best opportunities to assess the availability and cost of existing capacity resources is through an RFP process. As Staff acknowledges in its Final Comments, "[g]iven that it is impossible to know what the market may make available without putting out an RFP, Staff supports doing so."[112]

While a market study could provide a snapshot of existing resources that are uncommitted, the resources that are available at the time of the snapshot cannot be assumed to be available in the future. Likewise, complex regional adequacy studies can provide useful indications of the general conditions, but they are based on numerous assumptions and provide neither guarantee of availability, nor insight to cost. For these reasons, PGE believes that the issuance of an RFP is the best way to both assess the availability of market capacity and execute on available opportunities that are shown to be least-cost, least-risk. PGE will continue working with stakeholders in future IRPs to further explore questions related to market capacity.

### 5.5. IRP-RFP Relationship

***PGE's IRP exceeds the Commission's specificity requirements and the RFP Guidelines provide for a robust regulatory process.***

Staff, CUB, and Sierra Club raise concerns related to PGE's plan to issue an RFP following acknowledgement of PGE's 2016 IRP.

Staff notes that the IRP guidelines encourage a "reasonable level of specificity"[113] in the determination of resource acquisition strategies. They cite the Commission's decision not to acknowledge a PacifiCorp Action Plan item to acquire up to 800 MW over nine years as an example of a plan lacking specificity.[114] Staff's reliance on this decision from PacifiCorp's 2011 IRP is misplaced. In that case, the Commission found that PacifiCorp did not actually pledge any near-term action to acknowledge.[115] In declining to acknowledge the acquisition strategy, the

[111] Staff's Final Comments at 20.
[112] *Id.* at 19.
[113] Staff's Final comments at 33-34.
[114] *See*, In the Matter of PacifiCorp 2011 Integrated Resource Plan, Docket LC 52, Order No. 12-082 at 7, March 9, 2012.
[115] *Id.*

Commission stated that "[t]he purpose of an action plan is to identify specific near-term actions that the company plans to take to meet its resource needs."[116]

Unlike PacifiCorp, PGE is not requesting an open-ended acquisition plan far in the future. PGE has proposed specific near-term actions in the form of the issuance of RFPs to acquire resources to meet PGE's resource needs. PGE has provided additional specificity by describing the electric and environmental characteristics and associated qualifying technologies that it would be seeking in the RFPs.[117] The IRP Guidelines require only the identification of an action plan with resource activities that the utility intends to take over the next two to four years and a proposed acquisition strategy for each resource in its action plan.[118] PGE has gone beyond the requirements of the Guidelines by providing additional specificity about the resources it will seek in the RFP.

Parties also raise concerns related to resource evaluation in an RFP. Staff calls for an open-ended process with substantial input from stakeholders.[119] Sierra Club expresses concern about the ability of the Commission and stakeholders "to apply the level of scrutiny appropriate to major, long-term resource commitments."[120] Such concerns are unfounded.

The RFP process is robust with multiple opportunities for Commission and stakeholder input. Initially, a Commission-approved independent evaluator (IE) is involved in the development of a draft RFP. The Company then presents the draft RFP to stakeholders and bidders for feedback. PGE incorporates any feedback, as appropriate, into the final draft RFP, which the Company submits to the Commission.

The Commission then takes additional comments from stakeholders prior to approving an RFP for issuance. The Commission-approved IE provides a report to the Commission on the fairness of the RFP. This report generally covers all aspects of the process, including scoring methodologies. Upon consideration of all the relevant information, the Commission may approve the RFP as is, or may require minor or major changes. For instance, in Docket UM 1535, the Commission required PGE to combine the RFPs for energy and capacity needs.[121]

Following issuance of an RFP, the Commission-approved IE, in adherence to Oregon's Competitive Bidding Guidelines, works to ensure fair treatment for all bidders.[122] The IE also bears the major responsibility of verifying bid scores.[123] At the conclusion of the RFP, the IE files another report attesting to the fairness of the RFP.[124] Following the conclusion of the RFP, utilities must submit the final shortlist for Commission acknowledgement. The Commission relies on the IE's final report, and solicits comments from other stakeholders, prior to acknowledging the final short list.

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[116] *Id.*
[117] PGE's March 31, 2017, Reply Comments, Section 2.2.
[118] IRP Guidelines 4n and 13.
[119] Staff Final Reply Comments at 34.
[120] Sierra Club Final Reply Comments at 2.
[121] *In re Request for Proposals for Capacity Resources* Order No. 11-371 at 2 (Sep. 27, 2011).
[122] Order No. 14-149, Appendix A at 2, Guideline 5, and at 4, Guideline 10.b.
[123] *Id.*, Appendix A at 4, Guideline 10(d) and 10(e).
[124] *Id.*, Appendix A at 4 Guideline 11.

In short, the Commission has created a robust and transparent RFP process, with multiple chances for Commission and stakeholder oversight to ensure the acquisition of least-cost, least-risk resources, and mitigate the potential for bias in the RFP final results.

### 5.6. Benchmark Resources

***PGE is not seeking acknowledgement of a benchmark resource nor is it proposing to remove energy storage from a potential RFP.***

Several parties raise issues related to benchmark resources. CUB and NIPPC cite concerns with PGE's potential renewable benchmark resource,[125] while National Grid is concerned that PGE does not have an energy storage benchmark.

CUB and NIPPC are both concerned with the potential for PGE to be over-committed to wind and ask that the Commission not acknowledge the benchmark resource.[126] The concerns about over-commitment to wind seem inconsistent with the general preferences of the Commission, Staff, and stakeholders for RFPs in which a wide variety of resource types are permitted to participate. Concerns about diversity of location and type of resources are addressed in RFP bid scoring. In any event, the Company has not requested acknowledgement of a benchmark resource.

CUB correctly notes that a renewable RFP would examine the capacity contribution of proposed resources.[127] The 2016 IRP established a thorough methodology for evaluating the capacity contribution of renewable resources in the context of PGE's load and resource portfolio. Using this methodology, PGE will ensure that the value of renewable resources evaluated in an RFP will appropriately account for resource diversity benefits. The capacity contribution of any portfolio of procured renewable resources will not be limited to the capacity contribution of a specific bid; rather it will depend on the specific characteristics of the resources selected on the basis of cost and risk.

CUB's contention that "history has shown that the benchmark resource is the most likely resource to be acquired" is incorrect. In PGE's last renewable RFP, the benchmark resource was not selected. In PGE's last energy/capacity RFP, the capacity benchmark was selected; the energy benchmark was not selected; and no benchmark was proposed or selected for seasonal capacity. None of PGE's current utility scale wind resources (Biglow Canyon, Klondike II, Tucannon River, or Vansycle Ridge) were benchmark resources. PGE's history shows that the benchmark is <u>not</u> the most likely resource to be acquired.

National Grid is concerned that PGE is not pursuing an energy storage benchmark resource. It fears that "PGE may have made a preliminary determination to remove large-scale energy storage resources from consideration in the RFP."[128] PGE has not made a determination to

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[125] PGE has not yet signed definitive agreements which would enable it to submit a benchmark bid. PGE maintains the commitment it made in its Reply Comments to inform the Commission and parties, if and when it does so.
[126] NIPPC's Final Reply Comments at 3; CUB at 6.
[127] CUB at 7.
[128] National Grid's Final Reply Comments at 4.

remove energy storage from a potential RFP following IRP acknowledgement. The Company has simply chosen not to submit an energy storage bid for a "site-specific, self-build option" in an upcoming RFP. PGE will examine all technologies that meet the capacity needs identified in the 2016 IRP, including large-scale energy storage.

## 6. Load Forecast

PGE's load forecasting method is sound, appropriate and consistent with the IRP Guidelines and industry standards. The economic structure of and outlook for PGE's service area supports the resulting forecast, which is consistent with long-term historical growth rates. PGE shared its methodology and results with stakeholders via a robust IRP public process, which included multiple stakeholder meetings on load forecasting. The Company appreciates the thoughtful engagement with stakeholders on its load forecast methodology and looks forward to working with Staff and stakeholders in future IRPs to further enhance the methodology. However, despite the robustness and openness of PGE's public process, Staff continues to have concerns pertaining to: 1) PGE's load forecast reflecting higher growth than forecasts presented by other regional utilities and its own recent historical growth; 2) PGE's load forecast methodology, specifically the model specifications and choice of economic drivers in the regression models; and 3) the depiction of load forecast uncertainty in the IRP. PGE addresses these concerns in the sections below.

### 6.1. Projected growth rates

> ***PGE's forecast of energy deliveries growth rates are consistent with the above-average economic strength and fundamentals of PGE's service area and rationally differ from those of other regional utilities.***

Staff cites lower forecasted energy delivery growth rates at two Pacific Northwest utilities, Seattle City Light and Puget Sound Energy (PSE), to cast doubt on PGE's projected load growth rate. In doing so, Staff fails to consider regional variation and the underlying customer composition of the service areas.

PGE bases its long-term load forecast on steady, moderate growth in energy deliveries in the residential and commercial customer classes, and stronger growth from the industrial customer class—reflecting the fundamental drivers of the service territory.

Oregon, and in particular the Portland metro area, is a relatively unique area for its economic growth compared to the rest of the U.S. The Oregon Office of Economic Analysis[129] and the U.S. Bureau of Economic Analysis[130] have forecast that Oregon will maintain a growth advantage—in terms of both gross domestic product (GDP) and population growth—that is higher than that of the U.S. as a whole for years to come. Strong residential customer growth offsets long-term declines in average electricity usage-per-customer observed from increasing

[129] Oregon Economic and Revenue Forecast. May 16, 2017. Vol. XXXVII, No. 2. Accessed June 20, 2017: http://www.oregon.gov/das/OEA/Documents/forecast0517.pdf.
[130] http://www.oregon.gov/das/oea/Pages/Index.aspx.

adoption of energy efficiency measures and tighter building codes and standards for electricity use.

There are meaningful distinctions between utilities, which can cause differences in growth rates regionally and nationally. The largest difference between the utility forecasts cited by Staff and PGE's forecast appears to be in the industrial sector. As utility benchmark studies conducted by Itron have shown, industrial growth has much more extreme variation across utilities, with some utilities experiencing larger declines year-to-year, while others experience stronger growth.[131] Seattle City Light and PSE load forecasts reflect low to declining growth within their industrial customer sector, which is quite different from PGE's industrial forecast.

Beginning in the 1980's, Oregon's economic structure began to shift away from natural resource-based industries. A number of PGE's lumber and paper manufacturing customers have seen closures or decreases in production since this time. PGE's industrial forecast accounts for this structural shift in the Oregon economy by projecting declining growth for lumber and paper products in the next five years and flat (i.e., zero growth) demand over the long-run load forecast[132] (2021 through 2050) for its sub-transmission class (which is comprised of primarily lumber and paper customers).

Meanwhile, Oregon, and more specifically the Portland metro region, has become an economic hub for a number of newer industrial segments, most notably (as pertains to electricity consumption) the semiconductor manufacturing and data center sectors.[133] In fact, manufacturing comprises about 25% of the Portland metro GDP, more than twice the national share.[134] Though industrial energy deliveries growth rates have been volatile from year to year, PGE has seen strong growth in primary service industrial deliveries over the last 20 years, with a 20-year growth rate of over 3% and recent growth rates averaging above 4% over the past five years. PGE's forecast reflects that high tech industrial customers continue to play a leading role in the forecast growth for PGE's primary voltage service (e.g., industrial) customer class. With the continuing dominance of computer products and cloud services, PGE's long-term forecast annual energy deliveries growth rate averaging 2.6% for its primary voltage service class is a very reasonable projection.

While regional and other utility load forecasts can be interesting for comparison, each region and utility forecast should be evaluated based on the economic fundamentals and forecast methodology relevant to that region and utility. Comparing the load growth rate of two different utilities, without context or justification, is unhelpful, absent careful examination of the underlying drivers and outlook.

[131] https://www.bea.gov/.
[132] PGE also assumes a zero growth rate for Street Lighting and Traffic Lighting voltage service class due to the future penetration rates of LED technology.
[133] Data centers are technically classified as commercial services for NAICS purposes, but as primary service customers, they can be considered industrial.
[134] https://www.qualityinfo.org/-/portland-gdp-growth-ranks-10th-fastest-among-100-largest-metros

### 6.2. Forecast methodology

***PGE's load forecasting approach is consistent with industry practices.***

For the 2016 IRP, PGE introduced econometric, regression-based models for its long-term energy deliveries forecast. PGE identified a regression-based approach as advantageous compared to the use of historical growth rates, as econometric models incorporate explanatory variables, including fundamental drivers of growth in PGE's service territory and weather variables. This approach is consistent with the industry standard as presented by Itron in PGE's April 2015 IRP stakeholder public meeting. PGE held a dedicated technical workshop on July 15, 2015 for stakeholders to review the regression models, provide input, and discuss PGE's long-term load forecast methodology and results.

Staff's concerns with PGE's load forecast[135] focus on technical components of the model specification with respect to the underlying structure of the data series and the choice of GDP as an explanatory variable in the industrial (primary voltage service) regression model. While subsequent discussions have been valuable and provide insight for on-going analysis, Staff has not made any explicit recommendations for model specifications or drivers which it believes would be appropriate alternatives to PGE's current forecast models.

The use of GDP as an economic driver in the industrial model is a proxy for output, or the underlying demand for industrial activity within PGE service territory. Economic output variables are among the most commonly used at other utilities, followed by employment.[136] Additionally, PGE finds GDP to be a more appropriate driver—as a predictor of industrial deliveries for its service area—based on changes in the industrial segment, including sector shifts and advancement in automation, which have changed the relationship between energy deliveries and employment. However, PGE is open to analyzing stakeholder recommendations for other fundamental drivers for future consideration in its industrial model.

The only specific recommendation Staff has provided in its comments was to use a simple average growth rate as an adjustment to PGE's large industrial customer forecast[137]. PGE estimated the result of this suggestion would be a load forecast <u>increase</u> of 5.5 MWa.

In Final Comments, Staff attempts to discredit PGE's forecasted growth rates by comparing them to recent growth rates and forecasts prepared by regional utilities for their own service areas. PGE reiterates the risk in using such comparisons. While reasonableness with respect to historical growth rates is important, the use of econometric models, rather than an unsophisticated approach (based on historical averaging), is appropriate for PGE's forecasting models. The use of econometric models for energy deliveries forecasting represents sound and standard practice within the electric industry.

Finally, Staff's Comments include PGE recent growth of 0.16% for historical comparison.[138] In this case, Staff defines "recent growth" by using a quasi-10-year growth rate defined as the

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[135] Raised in Initial Comments, Final Comments and at a public meeting in February of 2017 (Staff's Final Comments incorrectly state this meeting occurred in February of 2016.)
[136] PGE Public Meeting #1, April 2, 2015, Itron Presentation, slide 16.
[137] Staff's Initial Comments at 9, load forecast action number 5

comparison of average load from 2010-2014 to average load from 2000-2004.This is not a reasonable comparison. Not only does this time period reflect extended economic recessions, it also appears to be an arbitrary choice, reflecting a period too short for use over the long-term. It is important, for historical comparison, that a sufficient historical period be considered to capture multiple business cycles—such as PGE's 30-year energy deliveries for 1985 to 2015, which have a growth rate of approximately 1.4%. PGE's regression-based forecast is an appropriate approach for long-term energy deliveries forecasting and its results are consistent with long-term historical growth rates.

### 6.3. Load forecast high/low growth scenarios

> ***PGE addresses load uncertainty in a manner consistent with OPUC Guidelines and prior IRPs.***

PGE prepared its high and low forecasts (e.g., forecast "jaws") in compliance with Guideline 4(b) and did not present the forecasts as confidence intervals on the base forecast in the IRP. The high and low jaws are alternative load growth scenarios that project high or low load futures within the bounds of the variance experienced in the past. Various combinations of changes in technology, economy, public policy, and other drivers of electric demand may achieve these high and low scenarios. PGE addresses the stochastic, weather-driven risk associated with the load forecast in the RECAP modeling.

Staff expresses concerns with PGE's purported refusal to "identify each of the alternative approaches that PGE has considered or analyzed and explain why PGE declined to use them."[139] PGE has received no requests to analyze alternative approaches to construction of forecast scenarios or bounds. As PGE has pointed out to Staff in response to data requests, there is no standard industry methodology or practice for constructing load forecast scenarios or bounds, and there are a variety of different methods employed by other utilities. Some of the alternate scenarios constructed by other utilities or forecasting entities highlight the sensitivity of the forecast to a particular driver, such as economic growth or electric vehicle adoption. PGE finds that an advantage of its choice of more generic high and low scenarios is that they are not tied to a specific driver outcome and they encompass a greater range of possible underlying causes driving high or low load futures. Staff seems to take issue with the use of load scenarios in general, but has not indicated what would be a suitable alternative approach to characterizing load uncertainty within the IRP.

A key function of the IRP public process is to allow utilities to receive the "benefit of the information and opinion contributed by the public and by the Commission."[140] PGE looks forward to engaging stakeholders in a full and active discussion of the high and low load forecast scenarios in future IRP roundtables and workshops. The Company encourages stakeholders to raise their questions and concerns early in the IRP process to ensure ample time for thoughtful consideration and discussion.

[138] Staff's Final Comments at 24, Figure 4, Staff Analysis, PGE's Forecasted Load Growth.
[139] Staff's Final Comments at 27.
[140] *In the Matter of PacifiCorp 2008 Integrated Resource Plan*, LC 47, Order No. 10-066 at 27, February 24, 2010.

# 7. Demand Response

PGE acknowledges the importance of pursuing all cost-effective demand response, particularly in light of the passage of SB 1547. The Company appreciates the enthusiasm expressed by Staff and others with respect to this resource.

## 7.1. Current initiatives

***PGE has been pursuing a number of opportunities in demand response.***

As described in the latest Smart Grid Report,[141] and elsewhere, PGE is currently pursuing a number of demand response pilots and programs. PGE is sympathetic with comments that it is "stuck in a pilot cycle"[142] and is building transition plans to deploy pilots at scale. A review of the following current pilots shows that PGE is not simply conducting demonstration projects, but is building a foundation for a resilient demand response portfolio:

- **Flex Pricing Pilot**: This program is testing a number of dynamic rate design and behavioral demand response methods to assess how best to engage residential customers effectively. Using a rigorous experimental design, PGE is evaluating the time-of-use rates, peak time rebates (opt-in and opt-out), and opt-out behavioral demand response. This pilot will provide for an understanding of demand impacts, enrollment rates, retention rates, and customer satisfaction. PGE is building the plan by deploying a version of this program to all residential customers in 2019, including (to the extent possible) integrating with the newest Energy Tracker tool being deployed in 2018.

- **Smart Thermostats**: PGE's current engagement with Nest to deploy smart thermostat demand response has been a great success. As of June 2017, PGE has approximately 3,800 customers enrolled in the program and initial findings indicate that the program should be cost-effective long-term, while achieving high levels of customer satisfaction. As part of a recent deferral reauthorization, PGE included a third-party evaluation memo. PGE also indicated that it is planning to open the program to non-Nest thermostats. While this program is still technically a pilot, PGE has no plans to slow enrollment and is pursuing an accelerated program scale through all possible avenues.

- **Energy Partner**: The Energy Partner program is an automated demand response offering to large commercial customers that started in 2013. The program currently has approximately 8.3 MW enrolled, which is below the program goal of 25 MW. There are many reasons that the program has struggled, including the exclusion of direct access customers, the relatively small amount of non-high-tech industrial load,

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[141] *See*, *In the Matter of Portland General Electric Company*, Annual Smart Grid Report, UM 1657, May 31, 2017. Accessed June 20, 2017: http://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAQ&FileName=um1657haq16327.pdf&DocketID=18404&numSequence=63

[142] Staff's Final Comments at 22.

the need to run in both summer and winter, and the relatively stringent rules for the program (see **Section 7.2.1** of these Reply Comments). The Company is currently looking to replace its current aggregator model with an implementation contractor. PGE plans to adjust the program to allow for a greater diversity of notification times and windows, cross-marketing with other programs, and lower-cost enablement options. PGE is hopeful that with these changes, this program will soon achieve its goals. The struggles in this program are important lessons that inform how achievable deployment targets are established for inclusion in the IRP.

- **Multifamily Water Heaters**: PGE recently filed a proposal for a water heater direct load control pilot in the multifamily sector. The multifamily market currently has an 87% market share for electric water heat, compared to 27% in the single family market. PGE believes the economies of scale that this market provides, coupled with the potential for split incentives between tenants and property managers, provide an opportunity to scale quickly. The pilot proposes a final target of 8,000 water heaters, which would be equivalent to 4 MW of capacity (averaged over summer and winter), surpassing deployment targets for this measure. [143] If the pilot meets the proposed targets, the deployments will help bridge the gap left by Energy Partner's current shortfall.

## 7.2. Response to Staff comments

### 7.2.1. *Barriers to adoption*

***PGE faces unique challenges to demand response adoption.***

As discussed in previous comments[144] and in a public meeting before the Commission,[145] PGE faces a unique environment for pursuing demand response. Parties should not improperly juxtapose the Company's efforts with those of other utilities. Differences, including use of different accounting standards, can comparatively inflate other's success when referenced against PGE. Some of PGE's barriers include:

- Direct Access limits availability of participation in DR programs. Many high potential participants (those with loads that appear suitable for DR) do not get their electric service from PGE. These Direct Access entities include several large industrial customers as well as the bulk of the national accounts in PGE's service area.

- Demand response programs are uniquely subject to both summer and winter deployment, because the PGE service territory is dual-peaking. This leads to a dilution of avoided costs across both seasons, effectively cutting the benefit and, therefore, available budget in half for a given season.

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[143] The IRP reference scenario targets 2.5 MW by 2021.
[144] PGE's March 31, 2017 LC 66 Reply Comments.
[145] Comments of PGE Staff Josh Keeling before the Commission during February 16, 2017 Special Public Meeting.

- Clear guidelines on cost-effectiveness and cost recovery do not exist. Without this clarity, it is both difficult and risky to make large-scale investments in potentially costly demand response initiatives.

- It takes time to grow awareness of DR in the region. Partners like the Northwest Energy Efficiency Alliance (NEEA) and the Energy Trust of Oregon are beginning to engage, which should help the Company's efforts.

Many of these barriers can be addressed over time, though some (e.g., direct access) will likely remain. PGE is open to Staff's suggestion to better streamline the process of testing and scaling demand response programs through a Demand Response Review Committee. The Company perceives the Committee as an avenue to increase both transparency and speed to market. PGE, however, believes a reduced regulatory process for approving programs should offset a Demand Response Review Committee process. Otherwise, the additional administrative efforts will only make the process more cumbersome. The Company also believes that improved clarity on issues of cost-effectiveness and cost recovery through the upcoming demand response docket should enhance the ability to make larger investments.

#### 7.2.2. *Opt-out rates*

> ***Implementation of an aggressive demand response scenario that relies on opt-out customers should be reviewed in a separate process.***

Staff's comments suggest that PGE pursue the high demand response scenario outlined in the IRP.[146] This scenario includes opt-out, time-of-use, and peak time rebates for all residential and small C&I customers. Any discussion of implementing opt-out rates should occur in a separate docket in which all of the ramifications for the Commission and the Company's customer engagement history and policy can be considered. While some regions are implementing opt-out rates, most notably time-of-use rates in California and peak time rebates in Pacific Gas & Electric's service area, there are many considerations that require further exploration. Most notably, potential equity issues around the impact of such a rate change would need a more detailed assessment. For these reasons, PGE does not agree with Staff's recommendation to pursue the aggressive scenario as an action in the 2016 IRP.

#### 7.2.3. *DR test bed*

> ***The Commission should address the DR test bed implementation through the Smart Grid Report process.***

PGE commends Staff's forward-thinking in proposing a DR test bed.[147] This approach could help PGE and stakeholders better understand how to overcome barriers to implementation, the balance between rates and programs, and how best to bundle different offerings. PGE adds that

[146] Staff's Final Comments at 21.
[147] Docket LC 66 - Staff's Response to PGE'S Third Set of Data Request No. 01.

an enhancement to the test bed proposal could be to include other Distributed Energy Resources (DER), such as solar PV and energy storage. PGE advocates creating opportunity for its Customer Programs department and Transmission & Distribution organization to pilot concepts around locational value, integration hosting capacity, and targeted DER deployment.

PGE believes the appropriate venue for addressing test bed development is through the Commission's review of the Smart Grid Report, rather than through the IRP process. The IRP process identifies resource need and evaluates supply- and demand-side options to meet long-term needs. IRP scope does not, and should not, include research project design, nor should it be the sole driving force for demand response program decisions.

### 7.3. Planned actions

In response to stakeholder comments, PGE is willing to take the following actions, within the framework of the Commission's review of PGE's Smart Grid Report:

- Work with Staff to identify methods to enable demand response adoption beyond the current target of 77 MW. While current targets represent an aggressive goal, there may be changes to the existing process and/or rulemaking that could foster expansion.
- Begin to scope and define the DR test bed concept. As mentioned in the 2017 Smart Grid Report, the test bed concept could include other DERs as well. PGE will address this process with stakeholders through the Smart Grid Report.
- Work with Staff to identify relevant stakeholders and members for the Demand Response Review Committee. Further, PGE will begin to better define this process, including how it might supplant current program planning, evaluation, design, and implementation.
- Continue to scale pilots and programs to make progress toward existing demand response goals.

## 8. Other

### 8.1. Decarbonization

> ***PGE seeks to conduct a decarbonization study to inform future IRPs.***

Through the public stakeholder process, PGE has received feedback that customers are increasingly interested in resources that contribute to the long-term capability to decarbonize energy supply. In the 2016 IRP, PGE reflected decarbonization, in part, through the inclusion of a non-zero carbon price assumption in the Reference Case—an assumption that received significant support among stakeholders. Since filing the 2016 IRP, PGE has heard from key stakeholders and individual customers that the IRP should reflect an increased focus on lowering carbon emissions. In this same time frame, the City of Portland and Multnomah County both passed resolutions to achieve 100% clean and renewable electricity supply by 2035 and a 100%

clean and renewable energy economy by 2050. PGE is actively engaged in identifying how the Company can help customers meet these goals. Achieving decarbonization, both in the electricity sector and economy-wide, would have far-reaching implications for the long-term planning process. PGE proposes to conduct an enabling study in the next IRP to address planning questions around decarbonization. In particular, PGE is interested in understanding the opportunities and challenges in achieving a 100% clean and renewable electricity mix over time and in understanding how decarbonization efforts in other sectors may impact the nature of electricity demand.

## 8.2. Distribution planning

Staff has proposed a potential process for addressing distribution system planning.[148] PGE is willing to work with Staff on these efforts and agrees that a request that the Commission open an investigation into DSP might be the appropriate first step.

## 8.3. Transmission

### 8.3.1. *Montana Wind Transmission*

> ***The availability and cost of transmission arrangements should not be assumed in portfolio modeling.***

PGE appreciates the interest from Parties concerning the potential to access Montana Wind resources. PGE discussed the modeling of Montana Wind during the IRP public meeting process, both the modeling to capture locational benefits (including significantly improved capacity contribution modeling) and the portfolio modeling methodology (including transmission costs). Some stakeholders expressed appreciation for the portfolio modeling, which allows potential bidders to see the estimated value of the locational benefits, and hence, the potential "budget" available to cover additional transmission costs.

In Section 7.2.1.1 of its Reply Comments, PGE presented a very high level scenario of how additional transmission costs may impact the value of Montana Wind in response to questions raised by stakeholders who may have been less familiar with transmission cost calculations. This scenario indicated that there is the potential for most or all of the locational benefits to be offset by incremental transmission costs.

In Final Comments, Sierra Club claims that PGE "had too easily dismissed low-cost wind portfolios-in particular, plans that include Montana wind" and that Montana wind portfolios should have been included in the Action Plan.[149] Additionally, Staff states that "[t]here is a real possibility for near-term availability for substantial transmission capacity from highly productive wind sites in Montana and Wyoming to Oregon."[150]

[148] Staff's Final Comments at 36-38.
[149] Sierra Club at 6-7.
[150] Staff's Final Comments at 12.

While claiming Montana wind is a "low-cost" resource, Sierra Club does not include the cost of transmission needed to deliver the resource to PGE's system. PGE notes that it is speculative to assume transmission availability, and as shown in PGE's Reply Comments, even if available, the cost of transmission may be substantial. Accordingly, PGE does not presume availability or cost in portfolio modeling and therefore, did not include Montana wind portfolios in portfolio scoring. However, PGE also would not exclude Montana resources from participating in an RFP process. PGE reiterates its statement from Section 7.2.1 of Reply Comments that all resources bidding into and 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 resources (or any other resource) will ultimately be the winning bin in an RFP process.

In Final Comments, NWEC suggested that "PGE may want to convene an informal group to discuss the complex timing and staging issues needed to gain access to valuable Montana wind resources."[151] In addition to participating in ongoing discussions in regional transmission planning groups, PGE plans to include a workshop focused on issues related to accessing Montana resources in the next IRP cycle. PGE looks forward to working with stakeholders on these issues.

#### 8.3.2. *Network Integration Transmission System*

> ***NIPPC's suggestions regarding conversion to BPA Network Integrated Transmission Service are unsubstantiated.***

In Final Comments, NIPPC restates the -claims it presented in Opening Comments regarding the benefits of converting to BPA Network Integrated Transmission Service (NITS) and unsupported allegations of undue discrimination. NIPPC further recommends that the Commission withhold acknowledgement of capacity actions until a NITS conversion study is completed.

NIPPC provides no evidence to support withholding acknowledgement of PGE's capacity actions. PGE presented a detailed response to NIPPC's initial NITS comments in Section 7.2.3 of the Company's Reply Comments and the response continues to be relevant to NIPPC's claims. While not restating all of the details previously covered, PGE notes the following:

1. PGE has analyzed its transmission options in compliance with Commission IRP Guidelines 1 and 5.[152]

2. NIPPC presents no evidence that PGE "has significantly more PTP transmission rights than it currently needs to serve its loads."[153]

3. NIPPC continues to misrepresent the cost of NITS service, implying a rate cap irrespective of historical trends or consideration for future BPA costs and investments.[154]

[151] NWEC at 8.
[152] *See*, 2016 IRP, Appendix A.
[153] NIPPC at 16.

4. NIPPC falsely claims that PGE refused to provide accurate information about its BPA transmission rights, disregarding the extensive information provided by PGE about active and deferred transmission rights in several Data Responses, including PGE's Responses to ICNU Data Requests No. 018, 019, and 027; and PGE's Response to NIPPC Data Request No. 019.
5. In its Final Comments, NIPPC does acknowledge that PTP transmission would need to be retained under a NITS conversion scenario, stating that "[t]o be clear, NIPPC supports PGE's retention of the existing PTP transmission rights necessary to make surplus sales or participate in the EIM . . ."[155] This would further erode the savings purported in NIPPC's comments, which were discredited in PGE's Reply Comments.

NIPPC's recommendations regarding PGE's use of transmission (including the recommendation to withhold acknowledgement of capacity actions until a NITS conversion study is completed), should be rejected as they continue to be without merit.

### 8.4. Avoided Cost

> ***PGE requests clear guidance from the Commission on updating avoided cost prices consistent with the updates included in this IRP.***

As required by Commission Order 14-058, PGE will update its current avoided costs within 30 days of IRP acknowledgement.[156]

Commission Order No. 10-488 states, "[f]or partially acknowledged plans or acknowledged plans with a range of on-line years for the next major resource acquisition, the Commission will indicate how the utility shall determine avoided costs."[157] PGE requests that the Commission provide PGE with clear guidance as to how PGE's avoided cost updates should be determined.

PGE's 2016 IRP identified the first major action for capacity in 2021 and the second major action in 2025. For renewables, in the absence of early action, the first major RPS action is identified for 2029.[158] If a renewables RFP is acknowledged, the first major RPS action is in 2021,[159] with the next major action in 2030.[160]

Should the Commission not acknowledge, or partially acknowledge PGE's IRP, PGE requests that the Commission clarify that the Company should update its avoided costs consistent with the IRP.

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[154] *Id.* at 12.
[155] *Id.* at 23.
[156] Order No. 14-058 at 25.
[157] NIPPC at 2.
[158] PGE's March 31, 2017 Reply Comments at 16.
[159] PGE's March 31, 2017 Reply Comments at 16.
[160] PGE's March 31, 2017 Reply Comments, Attachment B.1 at 6.

### 8.5. Public Process

The 2016 IRP has been the subject of significant interest among stakeholders. PGE appreciates the diverse perspectives that have contributed to the IRP process, but also recognizes that there are opportunities for improvement in the stakeholder engagement process. In particular, as the analytical complexity continues to increase, the IRP process will benefit from earlier and broader engagement of stakeholders. Stakeholders that engage throughout the public stakeholder process tend to have a greater understanding of the IRP process and IRP analysis, and contribute consistent and meaningful communication that produces a balanced and thoughtful long-term resource plan for customers.

To identify opportunities for process improvement, PGE conducted a survey among stakeholders and led a discussion about stakeholder process improvement at its first quarterly roundtable on February 10, 2017, Roundtable 17-1. As PGE works to implement the suggestions that arose in these discussions, the Company encourages stakeholders and OPUC Staff to maintain the level of engagement demonstrated in this docket in the ongoing public IRP process.

## 9. Conclusion

PGE's 2016 IRP meets, and often exceeds, the Commission's procedural and substantive requirements. PGE has demonstrated through a robust public process and rigorous and sound analysis that its preferred portfolio and proposed action plan presents the best combination of expected costs and associated risks for the Company and its customers. PGE respectfully requests that the Commission acknowledge it.

DATED this 23rd day of June, 2017.

Respectfully submitted,

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