ORDER NO. 17 386

ENTERED OCT 09 2017

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2016 Integrated Resource Plan.	ORDER

DISPOSITION: 2016 IRP ACKNOWLEDGED WITH MODIFICATIONS AND EXCEPTION

This order memorializes our decision made at the August 8, 2017 Public Meeting concerning Portland General Electric Company's (PGE) 2016 Integrated Resource Plan (IRP). We acknowledge all but one of the action items proposed in PGE's revised action plan, with modifications to several others. Appendix A to this order lists the acknowledged action items and modifications.

We do not acknowledge PGE's action item to issue a request for proposals (RFP) for 175 average megawatts (MWa) of new renewable energy resources. We agree to allow PGE the opportunity to file a revised action plan regarding renewable resource procurement and present that to the Commission.

I. INTRODUCTION

This IRP review played host to a complex and dynamic conversation about PGE's resource strategy during a time of significant change in electricity market conditions, environmental and energy policy, and customer engagement. In various ways, this conversation stretched the boundaries of our accustomed IRP process. We appreciate the robust engagement of PGE, Staff, intervenors, and interested members of the public, which gave us a broad context for considering PGE's IRP. Over the course of this process, PGE conducted supplemental analysis, updated inputs with more current data, and made several adjustments to its plan, including reducing its projected capacity need and committing to pursuing bilateral negotiations with existing regional generation resources.

The purpose of the IRP process is to provide the utility with the input and opinion of stakeholders and the Commission based on the reasonableness of the plan presented by the utility in its IRP filing. Our acknowledgment decision provides PGE with guidance to consider in making resource investment decisions that, ultimately, rest firmly with the company.[1]

We take seriously our role in informing PGE's direction, but also reinforce that we do not control PGE's resource decisions and that risks associated with such actions must be properly balanced between shareholders and customers. Our commitment is to provide well-considered feedback on the resource strategy reflected in the IRP and give fair regulatory treatment to resource decisions that the company ultimately makes.

In this time of significant change and uncertainty within the electric utility industry and markets we expect utility resource plans to reflect actions that manage risk and uncertainty, balance the interests of present and future customers, and allow for course corrections as industry evolution comes into greater focus. The major action items that emerged from PGE's IRP process, and that we acknowledge here, are consistent with that philosophy. For example, rather than committing to a new, large natural gas resource to meet its capacity need, PGE's revised capacity action item commits it to first fully consider lower-cost, lower-risk opportunities through short- to medium-term contracts with the existing regional infrastructure. At the same time, PGE will seek to reduce its long-term capacity need by engaging its customers to achieve high levels of energy efficiency and demand response.

PGE did not persuade us, however, that its action item to pursue an RFP for 175 MWa of new renewable energy resources by 2020 was a least-cost, least-risk action to achieve the 50 percent renewable energy target that Oregon's Renewable Portfolio Standard (RPS) requires the company to achieve by 2040.[2] We recognize that incrementally adding renewable energy resources over time may be a reasonable operational and cost-risk mitigating strategy to achieve this major system transformation. We also believe that near-term action to address long-term renewable energy obligations may be appropriate, provided that more attention is paid to balancing short- and long-term tradeoffs and to mitigating long-term risks. Based on the information and analysis provided in this docket, we conclude that PGE did not sufficiently demonstrate that the long-term cost

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[1] *See In the Matter of the Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon*, Docket No. UM 180, Order No. 89-507 at 6 (Apr 20, 1989) (explaining, "The Commission does not intend to usurp the role of utility decision-maker. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy while having the benefit of the information and opinion contributed by the public and the Commission * * *.").

[2] ORS 469A.005 through 469A.210 (establishing stair-step RPS requirements for PGE of 20 percent in 2020, 27 percent in 2025, 35 percent in 2030, 45 percent in 2035, and 50 percent in 2040).

savings it identified from near-term action were adequately balanced with the short-term rate impacts and long-term risks. Even so, we recognize that expiring tax incentives represent a time-limited opportunity that could significantly benefit customers. Since the company must act soon to capture the full value of the expiring tax incentives, we offer PGE the opportunity to present a revised action item for our consideration. In developing this revised action item, PGE should more fully consider short-term impacts and long-term risks, including renewable resource portfolio diversity and alignment with near-term system needs, strategies for avoiding or mitigating front-loaded rate impacts, resource sizing that maintains long-term optionality, and other considerations raised in this order and parties' comments.

II. IRP PROCESS

We require regulated energy utilities to prepare and file IRPs within two years of acknowledgment of the utility's last plan.[3] The IRP is a road map for providing reliable and least cost and least risk electric service to the utility's customers, consistent with state and federal energy policies, while addressing, and planning for, uncertainties. The primary outcome of the process is the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers. After selecting a best cost/risk portfolio, the utility develops a proposed "Action Plan" of resource activities to undertake over the next two to four years to implement the plan.

Our IRP guidelines provide procedural and substantive requirements for utilities to meet in developing their IRPs.[4] Consistent with our guidelines, a utility's IRP must include the following key components:

- Identification of capacity and energy needs to bridge the gap between expected loads and resources
- Identification and estimated costs of all supply-side and demand-side resource options
- Construction of a representative set of resource portfolios
- Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties
- Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers

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[3] OAR 860-027-0400(3).

[4] *See In the Matter of Investigation into Integrated Resource Planning,* Docket No. UM 1056, Order No. 07-002 (Jan 8, 2007) and Order No. 07-047 (Feb 9, 2007) (adopting 13 IRP Guidelines); *In the Matter of Investigation into the Treatment of CO_2 Risk in the Integrated Resource Planning Process,* Docket No. UM 1302, Order No. 08-339 (Jun 30, 2008) (refining Guideline 8 addressing environmental costs).

- Creation of an Action Plan that is consistent with the long-run public interest as expressed in Oregon and federal energy policies

In our guidelines, we instruct utilities to use at least a 20-year planning horizon for analyzing resource choices and to account for end effects. To evaluate the cost implications of various portfolios, we direct utilities to use net present value of revenue requirement (NPVRR) as the key cost metric.

In reviewing an IRP, we examine the resource activities in the Action Plan and determine whether to acknowledge them based on the reasonableness of those actions, given the information available at the time. Our decision to acknowledge or not acknowledge an action item does not constitute ratemaking. The question of whether a specific investment made by a utility in its planning process was prudent will be fairly examined in the subsequent rate proceeding. Acknowledgment, or non-acknowledgment, of an IRP is a relevant but not exclusive consideration in our subsequent examination of whether the utility's resource investment is prudent and should be recovered from customers.

III. PGE's 2016 IRP

A. Process

After PGE filed its IRP in November 2016, we adopted a procedural schedule. This schedule allowed numerous opportunities for submission of written comments from Staff and intervenors, and to obtain feedback from PGE.[5] We also solicited informal comments from the general public and held a Public Comment Hearing in Portland, Oregon.

Staff filed its final recommendations on July 27, 2017; Staff's report is attached for reference as Appendix B. PGE filed a response to Staff's report that includes a final, revised Action Plan for acknowledgment.[6] We made our decision at our August 8, 2017 Public Meeting.

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[5] Staff, Oregon 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), and Ed Averill on behalf of the Northwest Climate Methane Task Force. The Renewable Energy Coalition (Coalition) also filed a petition to intervene, which was not ruled upon before our August 8, 2017 decision.
[6] PGE Response to Staff Report (Aug 4, 2017).

B. Projected Capacity Resource Need

PGE requests that we acknowledge a projected 2021 capacity need of 561 megawatts (MW), 240 MW of which must be dispatchable. This assumes procurement of 175 MWa of new wind resources consistent with PGE's proposed Action Plan.

In its initial IRP filing, PGE proposed to issue one or more RFPs to acquire up to 850 MW of capacity, including 375 to 550 MW of long-term annual dispatchable resources and up to 400 MW of term-limited annual (or seasonal equivalent) capacity resources. To evaluate resource adequacy, PGE used Energy & Environmental Economics' (E3) RECAP model, with inputs assuming a long-term average load growth of 1.2 percent per year and 2020 retirement of its coal-fired operations at the Boardman generating facility. To assess its flexible capacity needs, PGE used E3's REFLEX model, which suggested that at 25 percent RPS approximately 400 MW of dispatchable resources will be required to avoid significant real-time imbalances on the system.

In its April 2017 update, PGE reduced its projected capacity need to account for re-negotiation of a large hydroelectric project contract, updates to its resource mix to include new proposed solar qualifying facilities added in accordance with the Public Utility Regulatory Policies Act of 1978 (PURPA),[7] and use of the updated load forecast in PGE's rate case in docket UE 319.

C. Projected Renewable Energy Resource Need

PGE proposes to procure 175 MWa of incremental long-term qualifying resources by 2020 to address a projected RPS compliance shortfall in 2029.

PGE uses Renewable Energy Certificates (RECs) to meet the annual requirements of Oregon's RPS. RECs, issued per megawatt-hour of qualifying generation produced, may be either bundled with energy or unbundled, where the REC and energy are exchanged separately.[8] PGE's current RPS obligation is 15 percent of annual retail sales; this increases to 20 percent in 2020, with further increases every five years to arrive at a 50 percent obligation in 2040. PGE's proposed long-run RPS compliance strategy includes reliance on banked RECs (saving RECs produced in one year to retire in a later year), maintaining a "minimum REC bank" to cover one- to two-years' worth of event risks, and procuring additional RPS-eligible renewable energy resources.

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[7] 16 USC § 2601, *et seq.*

[8] Use of unbundled RECs is limited to 20 percent of the RPS requirement; this limit does not apply to RECs issued for generation in Oregon by a PURPA qualifying facility. ORS 469A.145.

PGE states that the timing of its proposed near-term acquisition is intended to capture the maximum value of the Production Tax Credit (PTC),[9] which is available for resources that satisfy safe harbor requirements by year-end 2016 and comply with the assumed construction period. PGE estimates that this acquisition will allow it to hold its minimum REC bank level through 2040. PGE concludes that, under all of the futures it explored to quantify risk, near-term RPS procurement capturing the full value of the PTC is lower cost than adopting a delayed or "just in time" approach that would address the RPS need closer to when a REC shortfall is projected to occur.

In its initial IRP filing, PGE established 2025 as the last year it could fully comply with the RPS using existing resources and its accumulated REC bank without additional RPS-qualifying additions. PGE extended this projection in its April 2017 update by four years to 2029 to incorporate the addition of RECs from contracts with PURPA qualifying facilities executed through December 2016 and a reduced RPS obligation from use of the lower load forecast in docket UE 319.

D. Selection of Preferred Portfolio

PGE identifies "Efficient Capacity 2021" as the best cost/risk portfolio of energy resources under the assumptions used in its IRP analysis. This portfolio includes deployment of energy efficiency, demand response, conservation voltage reduction, and dispatchable standby generation. It also includes the addition of 515 MW of renewable energy resources (modeled as Pacific Northwest Wind), 370 MW of generic capacity (modeled as a simple-cycle natural gas-fired frame combustion turbine (frame CT)), and 389 MW of efficient capacity (modeled as a combined-cycle natural gas-fired combustion turbine (CCCT)).

In developing its IRP, PGE first designed 21 portfolios testing combinations of energy resources including "generic capacity," "efficient capacity," wind, solar, biomass, geothermal, and demand-side actions. PGE modeled "generic capacity" as the cost and heat rate characteristics of a frame CT, and "efficient capacity" as a CCCT. PGE explains these generic resources are intended to represent any resource that can provide similar cost and performance characteristics.

PGE then identified ten portfolios for further analysis. Using a 34-year planning horizon, PGE evaluated each portfolio under 23 potential futures using combinations of low, medium, and high scenarios for variables of natural gas prices, carbon prices, and load growth. PGE scored and ranked each portfolio based on NPVRR in the reference case and based on PGE's evaluation of risk in "severity," "variability," and "durability"

[9] 26 USC § 45 (establishing a per-kilowatt-hour tax credit for electricity generated by qualified energy resources and sold by the taxpayer to an unrelated person during the taxable year).

scenarios. Using the total combined cost and risk score, PGE narrowed its choices to four portfolios: RPS Wind 2018, Wind 2018, Wind 2018 Long, and Efficient Capacity 2021, ultimately selecting Efficient Capacity 2021 as the top portfolio.

E. Proposed Action Plan

To acquire the resources in its preferred portfolio, PGE proposes demand-side management through further acquisitions of energy efficiency and demand response, and expansion of its conservation voltage reduction program. PGE proposes supply-side actions of issuing RFPs for RPS-compliant resources and capacity resources, and further acquisitions of dispatchable standby generation. PGE also plans to submit a proposal for the development of energy storage systems consistent with 2015 House Bill 2193.[10] Finally, PGE identifies several enabling studies to inform its next IRP.

IV. DISCUSSION

A. Proposed Action Items

1. Acquire 135 MWa of Cost-Effective Energy Efficiency

PGE proposes to add, from 2017 through 2020, 135 MWa (176 MW) of energy efficiency savings. PGE states that it continues to work collaboratively with the Energy Trust of Oregon (Energy Trust) to assure sufficient funding for the acquisition of all cost-effective energy efficiency, subject to consumer adoption constraints. PGE states that actions taken during the two- to four-year Action Plan window will support continued cost-effective acquisitions beyond 2020.

a. Comments

Staff, CUB, NWEC, and Sierra Club comment that PGE should plan for higher energy efficiency targets. They caution that PGE's IRP likely suffers from under-accounting of available energy efficiency projections, especially in the longer timeframe where technological developments 15 to 30 years in the future may exceed current expectations. Staff notes that, 2016 Senate Bill 1547 provides utilities a clear signal that energy efficiency should serve as a priority resource in resource acquisition plans.[11] Staff recommends that we acknowledge this action item with certain modifications.

NWEC also raises concern about interruptions to energy efficiency incentives for large customers during the Action Plan horizon due to large user energy efficiency funding

[10] Oregon Laws 2015, Chapter 312, Sections 1-4 (requiring subject electric companies to submit proposals to develop energy storage systems and to procure authorized projects by 2020).
[11] Oregon Laws 2016, Chapter 28, Section 19 (directing electric companies serving customers in Oregon to plan for and pursue all available energy efficiency resources that are cost effective, reliable, and feasible).

caps at the Energy Trust. NWEC cautions that failing to acquire the least-cost resource is not in the best interest of customers.

b. Resolution

We acknowledge PGE's action item of acquiring 135 MWa of energy efficiency with the following modifications:

(1) Changes to 2021 capacity need must use the Energy Trust's most recent forecast data;
(2) PGE will provide an update on the Energy Trust's activities and progress on the large customer funding issue in its IRP update in 2018; and
(3) PGE will make available the Energy Trust's energy efficiency forecast data and provide an explanation of their model in the company's next IRP.

In making this decision, we highlight two points. First, historically, energy efficiency has continued to grow and outpace the Energy Trust's long-term energy efficiency projections, including PGE IRP targets. We expect the company, between now and the next IRP or the company's next sizing of long-term supply resources, to better identify the steps it must take to convert more aggressive reach goals into real demand-side resources. We further expect the company to incorporate a stretch goal for efficiency savings that it can be comfortable with in its resource decisions. In making rate decisions concerning long-term resources, these higher levels of energy efficiency savings will be increasingly relevant considerations.

Second, we recognize parties' concern that caps on funding for large user energy efficiency may prevent Energy Trust and PGE from acquiring all cost-effective conservation, the least-cost resource. We continue to encourage PGE to work with all applicable parties to attempt to resolve the large customer program funding barriers.

2. Acquire 77 MW (winter) and 69 MW (summer) of Demand Response

PGE proposes to expand its demand response resources, targeting an aggregate capacity addition of 77 MW (winter) and 69 MW (summer) through 2020. PGE states it plans to implement a diverse set of programs that target residential, commercial, and industrial customers. To establish these demand response targets, PGE used a demand response potential study developed by The Brattle Group in 2015.

a. Comments

Staff, CUB, NWEC, and ODOE comment that these targets are too conservative. They believe that even more of PGE's capacity needs can be met with demand response assets, with the beneficial effect of further reducing the need for long-term investments in large, new generation.

Staff raises concern that PGE is "stuck" in a demand response pilot cycle and that the company does not yet consider demand response to be a full-scale resource. Staff recommends that we acknowledge this action item but make clear that PGE's proposed targets are minimum acquisition amounts. Staff offers a series of actions that it believes will help PGE enhance its demand response planning, accelerate the pilot-to-resource cycle, and drive market maturity.

b. Resolution

We acknowledge PGE's action item of acquiring 77 MW (winter) and 69 MW (summer) of demand response with the following modifications:

(1) Through 2020, acquire at least 77 MW (winter) and 69 MW (summer) of new demand response resource as a floor, while working to reach the demand response high case targets of 162 MW (summer) and 191 MW (winter);
(2) hire a third party to conduct a study for demand response specific to PGE's service territory with results in time to inform PGE's subsequent IRP;
(3) work with Staff to establish, manage, and support a "Demand Response Review Committee" to assist in the development and success of PGE's demand response activities including review of PGE's proposals for demand response programs; and
(4) within nine months (of August 8, 2017), present multiple viable demand response test bed sites to the Demand Response Review Committee, and by July 1, 2019, establish a demand response test bed.

As with our decision regarding energy efficiency, we highlight the importance of these demand-side resources as a means to reduce the need for additional supply-side resources. We view the time between now and PGE's next IRP—and before we are asked to acknowledge any significant long-term supply-side capacity addition—to be a critical opportunity for PGE to more aggressively develop demand response as a resource to address its capacity needs.

3. Deploy 1 MWa of Conservation Voltage Reduction

PGE proposes to pursue programmatic conservation voltage reduction deployment, targeting minimum energy savings of 1 MWa through 2020. Conservation voltage reduction is a means of lowering consumer power demand by operating distribution feeders within the lower portion of the acceptable voltage bandwidth. To enable this conversion, PGE proposes to pursue smart meter voltage data bandwidth expansion and data analytics research and development efforts to support system-wide expansion of a dynamic conservation voltage reduction program.

a. Comments

Staff finds the proposed action item generally acceptable (no other party provides a position). Moving forward, Staff suggests that PGE describe the flexibility of its conservation voltage reduction program in greater detail including an analysis of the distribution feeders on which conservation voltage reduction has been deployed. Staff proposes that PGE report on this program in its Smart Grid docket (UM 1657).

b. Resolution

We acknowledge PGE's action item of deploying 1 MWa of conservation voltage reduction through 2020 as described in its 2016 IRP. We direct PGE to report in docket UM 1657 on its conservation voltage reduction program. This report should include an analysis of the distribution feeders on which conservation voltage reduction technology has been deployed.

4. Issue RFP for 175 MWa of New Renewable Energy Resources

PGE proposes to issue an RFP for approximately 175 MWa of new renewable energy resources by 2020. This is equivalent to 515 MW of Pacific Northwest wind—the resource PGE modeled in most portfolios.

PGE's analysis determines it has a time-limited opportunity to maximize the available PTC, worth $23 per megawatt-hour for projects started in 2016, but diminishing annually through 2020, when it phases out completely. Based on its 34-year analysis, PGE concludes that adding 175 MWa of 100 percent PTC-eligible wind resources by 2020 results in a $173 million reduction in NPVRR relative to waiting to add renewable resources until its REC bank exhausts in 2029.[12]

Responding to stakeholder comments, PGE conducted supplemental analysis including sensitivities such as more rapidly declining technology costs, zero load growth, zero minimum REC bank, and a shorter NPVRR planning horizon. PGE states that, consistent with the IRP guidelines, it took into account the near-term financial impact on existing customers through use of a discount rate to weight costs incurred at different times.

[12] In reply comments, PGE provided supplemental analysis testing the impact of a 20-year planning horizon. PGE determined that early RPS action resulted in NPVRR savings even over that shorter timeframe. PGE Reply Comments at 22-23 (Mar 31, 2017).

PGE emphasizes that, in addition to reducing RPS compliance costs, new renewable resources would provide immediate benefits to existing customers. From an operational level, new resources would add capacity and energy to PGE's system. More broadly, PGE highlights, bringing new physical resources on line instead of using banked RECs achieves more carbon emission reductions, as supported by customers commenting in this docket and consistent with Oregon state policy.

PGE clarifies that renewable resources other than Pacific Northwest wind, both physical and REC-based, would be considered in the RFP. PGE expects that issuing an RFP while the PTC and the Investment Tax Credit (ITC) for solar resources are still at high value will drive down the price of all resources bidding into the RFP for selection.

Finally, PGE responds to questions of whether this type of action item is properly within the scope of the IRP process. PGE concludes that nothing in Guideline 4, which describes the components of the IRP, limits the identification of need or the construction and evaluation of portfolios to considerations solely within the two- to four-year Action Plan window. PGE interprets Guideline 1.d, which requires that the Action Plan "[b]e consistent with the long-run public interest as expressed in Oregon and federal energy policies," to instruct it to plan within the IRP for any needs that arise due to state policies such as the RPS. PGE cautions that overly focusing on near-term need is inconsistent with the IRP's intended function as a long-term planning instrument.

a. Comments

(1) Parties Supporting Early Procurement

NIPPC, NWEC, ODOE, RNW, Sierra Club, and many members of the public comment generally in support of early procurement of RPS resources. NWEC, RNW, and Sierra Club encourage PGE to pursue even greater amounts of renewable energy resources than the proposed 175 MWa to more fully capture the potential NPVRR savings.

These parties find PGE's economic analysis substantiates the findings in its IRP. They suggest that many unique risks and uncertainties favor early action to procure significant amounts of renewable resources—including missed opportunities to secure high quality renewable sites and the practical and operational considerations in meeting the company's steadily increasing RPS obligation. Like PGE, they emphasize that renewable resources provide immediate capacity and energy value to the utility's system—and add that the RFP process may uncover renewable resources of even higher capacity value.

They highlight that their members, and many members of the public and elected officials from communities that PGE serves, commented strongly in support of carbon emission reduction and the expedited transition to greater reliance on renewable energy.

Finally, they conclude like PGE that our IRP guidelines and past practices do not limit resource acquisitions to addressing near-term needs. They urge that a core value of the IRP is to ensure that resource decision-making reflects long-term considerations. Further, they argue that, even if a near-term need were a prerequisite for acknowledgment of a near-term IRP action, the proposed renewable action item would meet this standard because resources procured through the RFP would contribute to PGE's identified near-term capacity need as well as its longer-term RPS compliance need.

(2) Parties Opposing Early Procurement

Staff, CUB, and ICNU conclude that PGE has not demonstrated that its renewable action item will lead to the best combination of cost and risk for customers. They raise one or more of the following concerns:

First, Staff, in particular, asserts that acknowledgment of a near-term action to satisfy a long-term need—in this case, a need for RECs for RPS compliance in 2029 or later—is inconsistent with our IRP guidelines and past practices. Staff concludes that, taken together, IRP Guidelines 4.n and 1.c require that utilities include in their Action Plans resource activities that must be undertaken to meet system needs occurring in the two- to four-year Action Plan period, with analysis of the impacts of those resource activities over a long-term horizon.[13] Staff states that the Commission has consistently applied the guidelines so that Action Plans, which address near-term identified needs, are informed by the IRP's analysis of long-term uncertainties. Staff notes that it found no instance in past IRPs where we allowed a long-term need to exclusively or primarily drive resource procurement in the Action Plan window without a near-term need for the resource.

Second, even if our guidelines and practices are not determinative, these parties caution against acknowledging a near-term resource action based on the economic analysis of meeting a long-term need. They reason, with the projected need more than a decade away, any claimed economic benefit is necessarily based on assumptions and highly uncertain. They consider PGE's proposal a speculative economic hedge against a regulatory requirement—in a landscape where both the economics and the regulatory landscape are likely to change. The effectiveness of this hedge, they explain, could be impacted by the emergence of new resource opportunities, re-extension of the PTC, changes to the RPS, availability of economic transmission from Montana or Wyoming, grid paradigm changes resulting in load loss, restructuring of the Bonneville Power Administration, PGE reaching the statutory cost cap of four percent of revenue

[13] Guideline 4.n requires "[a]n action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources;" and Guideline 1.c instructs, "The planning horizon for analyzing resource choices should be at least 20 years and account for end effects."

requirement,[14] and numerous other events. Further, they note, even the date of the long-term need is a projection. This projection shifted out four years to 2029 during the time of this IRP review and is based on debatable assumptions that PGE will purchase no unbundled RECs and maintain a minimum REC bank.

ICNU provides independent analysis suggesting that an early-action RPS strategy is costlier for customers than a just-in-time strategy. ICNU estimates that PGE's proposed action item would result in increased costs of $336.5 million, on a NPVRR basis over the 20-year period 2018 to 2037.[15]

Finally, Staff, CUB, and ICNU caution that this request unfairly shifts out-year RPS compliance costs to current customers. The projected savings, they warn, are merely illusory to existing customers, who would incur a cost to pay for a resource that they do not currently need—so that future customers' needs can be met at a lower cost. They state that increasing rates to pay for a resource not yet needed is contrary to regulatory principles that customers should pay for the costs that are necessary to serve their load. They believe this is particularly true for a resource that, while it provides capacity and energy to customers in the near-term, is selected through an analysis that has been oriented toward minimizing the costs of meeting a long-term regulatory need.

b. Resolution

PGE's proposal to acquire 175 MWa of new renewable energy resources in the near-term to reduce the long-term cost of meeting a future RPS compliance need acutely highlights a current challenge in long-term utility resource planning. New legislative mandates to incorporate higher levels of renewable resources are adding new considerations to PGE's resource planning strategies. Moreover, unique attributes of renewable resources, including available tax credits and changes within the electricity markets, present conflicting considerations as to the timing of these resource acquisitions.

Recent changes to Oregon's RPS have increased the scope and complexity of PGE's long-term resource planning. In addition to considering operational needs, PGE must also ensure that 50 percent of its load is served by renewable resources by 2040. This represents a system transformation that will require PGE to incorporate a significant amount of new resources and adapt to a fundamentally different resource portfolio over a relatively short period. To accomplish this in a manner that best protects customers, PGE

[14] ORS 469A.100(1) provides that "[e]lectric utilities are not required to comply with a renewable portfolio standard during a compliance year to the extent that the incremental cost of compliance, the cost of unbundled renewable energy certificates and the cost of alternative compliance payments under ORS 469A.180 exceeds four percent of the utility's annual revenue requirement for the compliance year."
[15] ICNU Final Comments Attachment B at 12 (May 12, 2017). Mr. Mullins further calculates that, even if unbundled RECs are not considered, the early action portfolio still costs customers $30.7 million on an NPVRR basis. *Id.*

must plan to harmonize these operational and regulatory needs in a least-cost and least-risk manner. Using renewable resources to meet near-term capacity and energy needs can allow PGE to gradually gain experience with higher levels of variable resources, and can also reduce the likelihood that RPS requirements will force resource additions at times not otherwise needed to serve load.

Adding to this increased complexity are competing factors affecting the timing of resource acquisition. On one hand, the unique attributes of renewable resources may favor earlier action than would be required for traditional resource investments. Significant tax incentives available today, but rapidly diminishing in value, may make renewable resources less costly today than in the future. Moreover, because the value of renewable resources is location-dependent, particularly for wind resources, sites with favorable resource regimes, transmission access, and permitting conditions may become increasingly constrained and drive up future resource costs.

On the other hand, delaying resource additions can minimize near-term rate impacts, avoid overcommitting to resources if future utility load is smaller than expected, and maintain optionality in future resource selection to take advantage of new market opportunities and technological advances. Cost-competitive renewable and flexible capacity resource choices may emerge that are more diverse and scalable, potentially allowing utilities to consider smaller resources with fewer long-term risks than larger resources. These evolving conditions create a greater need for PGE to consider the tradeoffs between long-term cost savings and the risk-mitigation benefits of retaining optionality.

Our IRP guidelines and policies continue to provide the necessary framework to address these new challenges. The focus remains on determining a utility resource need, and then evaluating potential utility actions to meet that need in a least-cost and least-risk manner. In reviewing an Action Plan, we will continue to look to see how individual action items fit into a comprehensive integrated strategy for meeting customer needs and whether the risks are appropriately shared between ratepayers and shareholders.

How utilities characterize need and assess risk and uncertainty within their IRPs and how we integrate that analysis into our review, however, must evolve. Traditional resource strategies, and the Commission's past treatment of such strategies, may have less relevance as utilities undergo system transformation in a time of evolving regulatory change, rapid technological advancements, increasing customer options, and market uncertainty. In this time of transition, we challenge utilities and stakeholders not to view our IRP guidelines as pre-established checklists but rather to proactively adapt their assessment of risk and uncertainty as industry evolution comes into greater focus.

PGE met this challenge in planning for its capacity needs. As discussed above, PGE responded to concerns about the risks and uncertainties of acquiring a new, large natural gas resource by further exploring short- and medium-term contracts with existing hydropower resources and other generators in the region. PGE fell short of this challenge, however, with regard to its renewable resource action item as its analysis did not evolve to respond to Staff and intervenors' concerns with the balance of near- and long-term tradeoffs and the assessment of long-term risks. In justifying such near-term action, PGE's strategy should have considered, among other things, how renewable resources could contribute most cost-competitively to near-term capacity and energy needs, the role PURPA qualifying facility additions will play in RPS compliance, and the proper sizing of resource investments to balance near-term opportunities to minimize future compliance costs with preservation of optionality through retaining RPS headroom to fill with future technological advances and opportunities.

Without a clear demonstration of how the projected long-term economic benefits were balanced with short-term impacts and long-term risks, we are unable to conclude that acting now, in the manner that PGE proposes, to take advantage of the economic opportunity is a least-cost and least-risk approach to meeting PGE's RPS need.

PGE primarily justified the size, timing, and expected technology characteristics of its proposed acquisition on the basis of projected long-term RPS compliance savings. In estimating these savings, PGE relied more heavily than usual on long-term analysis. PGE used a 34-year NPVRR, rather than the traditional 20-year period, and compared a near-term resource investment to a future resource investment. Further, when Staff and intervenors raised concern with the equity of short-term rate impacts and long-term benefits, PGE fell back on traditional IRP principles of discount rate and NVPRR rather than considering other approaches to balance these considerations. The absence of a clear imperative to act in the near-term made engagement on these issues critical to our decision.

In addition, PGE's sizing of the 175 MWa resource addition was not well explained and justified, except on the basis that projected NPVRR benefits increased with the size of the resource, up to a point. PGE did not adjust the sizing even in light of a high number of new PURPA qualifying facility contracts and requests for contracts (though PGE did extend its expected REC shortfall date by four years). Nor did PGE include smaller wind resources in the proposed portfolios it analyzed, or explain how the RFP would be able to select a smaller resource (if cost-competitive) to retain headroom to capture future technological advancements, customer choice options, and changes in load growth. Throughout, PGE's renewable energy proposal looked like a wind benchmark resource sized to meet 20 percent of its incremental need to reach the 50 percent RPS requirement in 2040. A greater showing of how the proposed resource action aligns with current capacity needs, how PGE can mitigate short-term rate impacts, and how long-term optionality can be maintained, was lacking in PGE's analysis.

Although we do not acknowledge the action item as proposed, we recognize that expiring tax incentives, particularly the PTC, represent a time-limited opportunity that could benefit PGE's customers. Since the company must act soon to realize the full value of these incentives, we encourage PGE to work with Staff and other parties to prepare and submit for our consideration a revised Action Plan for renewable resource acquisition that addresses the concerns noted in this order.

5. Pursue Bilateral Negotiations; Issue All-Source RFP for Any Remaining Capacity Needs

In its initial IRP filing, PGE projected an 819 MW capacity need in 2021, after taking into account its proposed demand- and supply-side action items and accounting for imports and executed PURPA qualifying facility contracts for facilities not yet online. PGE proposed to issue one or more RFPs to acquire up to 850 MW of capacity, and consider a mix of annual and seasonal resources. PGE noted that it may also enter into short- and medium-term contracts to maintain resource adequacy during any gap between when capacity is first needed and the time it takes for resources to be acquired through an RFP. In reply comments filed in March 2017, PGE clarified that it assumed the loss of two expiring hydro contracts in this projection.

As the IRP process continued, PGE updated its capacity projections and adjusted its procurement strategy. PGE successfully renewed one expiring contract (the Wells hydroelectric project) and reports it is negotiating renewal of the other (Portland hydro projects). PGE states it is systematically pursuing bilateral negotiations with other generation resources in the region, particularly existing hydro capacity. PGE estimates that volumes of 100 to 400 MW are available from multiple sellers, generally for five to 15 years. PGE explains that, with hydro resources typically unwilling to bid into competitive solicitations, it plans to submit any executed contracts for our review along with a request for waiver of our Competitive Bidding Guidelines.[16] PGE states it will not move forward with the RFP if it obtains sufficient capacity through bilateral negotiations. Still, it requests acknowledgement of the proposed RFP to ensure it is positioned to act quickly should it be unable to contract sufficient capacity.

PGE proposes the following revised set of action items to procure needed capacity:

> Acknowledge a capacity need of 561 MW, 240 MW of which must be dispatchable, in 2021. Procure capacity via bilateral negotiations and filing of

[16] PGE filed an Application for Waiver of the Competitive Bidding Guidelines on August 25, 2017. This matter is docketed as UM 1892.

waiver of Competitive Bidding Guidelines. Issue all-source RFP for any capacity needs (including dispatchable capacity) that may remain unfilled after completing bilateral negotiation process

a. Comments

Staff and intervenors comment that PGE did not properly consider short- to medium-term resources and recommend that PGE pursue bilateral negotiations to secure existing capacity resources, especially hydro generation, ahead of any capacity RFP. They question whether PGE properly compared different resource options and suggest that PGE's use of proxy resources is too generic to accomplish the intended purpose of the IRP. Although they generally agree that PGE's analysis demonstrates some mid-term capacity need, they question whether PGE truly needs the all-source RFP it proposes.

Staff recommends the following sequential approach to meet customers' capacity needs:

(1) Complete bilateral negotiations and report to Commission;
(2) complete market study;
(3) re-run models and develop new preferred portfolio using data from bilateral contracts, market study, and any other analyses; and
(4) issue an RFP for specific short- to medium-term resources.

PGE responds with specific concerns about the last three conditions. Regarding a market study, PGE explains that the current bilateral negotiations are essentially a market study. To developing a new preferred portfolio, PGE explains this would be a very time-consuming undertaking and not a matter of simply updating inputs. Finally, to a limited RFP, PGE responds that current bilateral negotiations already encompass the bulk of the short- to medium-term availability. PGE states that requiring it to follow these extensive negotiations with the recommended limited RFP would be repetitive and cost valuable time. PGE cautions that, with all these intermediary steps, if it were to ultimately find itself capacity short and needing the all-source RFP, it would be left with an abbreviated timeline, which could limit its procurement options.

b. Resolution

We acknowledge PGE's capacity need of 561 MW, 240 MW of which must be dispatchable, in 2021. With regard to procuring resources to meet this capacity need, we acknowledge the following modified sequential approach:

(1) Complete bilateral negotiations, with periodic updates to Staff as to status of negotiations and progress toward completing negotiations of key terms and conditions;

(2) concurrently, work with Staff and stakeholders to scope and launch a regional market study of potentially available resources to be run in parallel with the company's efforts to complete the bilateral negotiations; and

(3) report to the Commission, within four months (of August 8, 2017), the results of the bilateral negotiations and the need for: (a) completing the market study; (b) re-running models and developing a new preferred portfolio using data from the bilateral contracts, the market study, and any other new analyses; and (c) issuing an initial RFP for specific short- to medium-term resources before proceeding with an all-source RFP.

We agree with parties that short- to medium-term contracts provide optionality in the face of tremendous uncertainty in the energy market and could help PGE avoid committing customer dollars to irreversible, long-term resource decisions that may not be the least-cost path. We adopt this measured approach in an effort to balance the time required to complete bilateral negotiations (PGE estimates three to four months), Staff and intervenors' concerns about fully exploring the market and developing the in-depth perspective that was lacking at the beginning of this IRP, and PGE's interest in being positioned to act quickly to procure capacity if negotiations fall short.

We will evaluate the continued need for the market study, new preferred portfolio, and limited RFP when PGE presents its report on the results of the bilateral negotiations.

6. Acquire 16 MW of Dispatchable Standby Generation

PGE proposes to pursue expansion of dispatchable standby generation by 16 MW to meet standby capacity needs (non-spin). Through its dispatchable standby generation program, PGE contracts for the use of customers' standby generators when the local region has a need for critical power. PGE proposes to also pursue actions, such as customer site development and contract negotiations, to achieve additional annual standby targets, if needed beyond 2020. We adopt Staff's recommendation to acknowledge this action item.

7. Submit Storage Proposal in Accordance with House Bill 2193

PGE proposes to submit, in accordance with 2015 House Bill 2193, one or more proposals to the Commission by January 1, 2018, for developing a project that includes one or more energy storage systems that have the capacity to store at least five megawatt-hours of energy. We adopt Staff's recommendation to acknowledge this action item.

8. *Perform Enabling Studies to Inform Next IRP*

Based on the recommendations of Staff and stakeholders we require the following studies to inform PGE's next IRP:

- Treatment of Market Capacity
- Flexible Capacity and Curtailment Metrics
- Customer Insights
- De-carbonization
- Accessing Resources from Montana
- Load Forecasting Improvements
- Risks Associated with Direct Access

We do not adopt the additional studies suggested by ODOE, as we find these already required in other contexts.

B. Additional Requirements or Recommendations for PGE's Next IRP

Based on recommendations made by Staff and other parties, we adopt the following requirements for PGE's next IRP:

Load Forecasting	Conduct ongoing workshops, including consideration of probabilistic forecasts, with interested stakeholders to improve PGE's forecasts. Conduct out-of-sample testing and select models based on these results. Include a technical appendix that describes forecast methodology and contains a list of the forecast modeling assumptions (and explanations) and the model specifications (equations).
Portfolio Ranking and Scoring Metrics	Hold workshops with interested parties to develop a simple and clear set of portfolio scoring metrics, with a focus on using only metrics that have a clear interpretation and robust discussions on the appropriate way to incorporate short- and medium-term options and the relative importance of high-cost versus low-cost outcomes.[17]
Distribution System Planning	Work with Staff and other parties to advance distributed energy resource forecasting and distributed energy resource representation in the IRP process. Work with Staff to define a proposal for opening a distribution system planning investigation.
Transmission	Hold a workshop to explore the issue of transmission and the potential access to higher capacity wind resources in Montana and Wyoming.

[17] We direct Staff to report back to the Commission periodically on the status and outcome of these workshops.

C. Impact on PURPA Avoided Cost Prices

In its final reply comments, PGE requests that we provide clear guidance on how our determinations in this docket impact its avoided cost prices. In its report for the August 8, 2017 Public Meeting, Staff offered a position on how it would interpret the 175 MWa renewable energy resource and its impact on PGE's renewable deficiency period, were it acknowledged.

Staff clarified orally at the August 8, 2017 Public Meeting that it is not requesting a decision at this time from the Commission. The Coalition and NIPPC commented that our typical practice is to have a utility update its avoided cost pricing within 30 days of our IRP decision, and then use that separate process for any price changes. They cautioned against changing policy on an *ad hoc* basis in a utility-specific proceeding.

We find it premature to make a decision around PURPA avoided cost pricing and reserve our decision for our review of PGE's update that follows this IRP decision. We recognize the avoided cost process is linked to the IRP process, but we believe it should remain separate.[18]

V. PGE's 2013 IRP

We acknowledged PGE's last IRP in Order No. 14-415, with certain revisions and additional requirements.[19] In our prior order, we required PGE to hold several workshops and conduct certain studies and research to inform its next IRP. We agree with Staff that PGE has adequately complied with these requests and directives.

Staff recommends we direct PGE to carry forward certain studies. We agree these studies continue to be relevant and useful. We direct PGE to complete the following in developing its next IRP:

- Continue to evaluate non-physical compliance with Oregon's RPS
- Continue activities to test and assess the technical and economic viability of converting the Boardman generating facility to a biomass facility

In its continued evaluation of non-physical compliance with the RPS, we direct PGE to demonstrate it has followed industry best practices for incorporating unbundled REC

[18] PGE filed updated avoided cost prices on August 18, 2017. We addressed this filing at our September 12, 2017 Public Meeting, where we adopted a 2021 deficiency period for nonrenewable avoided cost prices and a 2025 deficiency period for renewable avoided cost prices. *In the Matter of Portland General Electric Company, Application to Update Schedule 201 Qualifying Facility Information*, Docket No. UM 1728, Order No. 17-347 (Sep 14, 2017) (directing PGE to file a revised schedule for Staff compliance review).

[19] *In the Matter of Portland General Electric Company, 2013 Integrated Resource Plan*, Docket No. LC 56, Order No. 14-415 (Dec 2, 2014).

market projections into its least-cost, least-risk RPS compliance strategy. With respect to its Boardman activities, we direct PGE to include analysis of the value of continuing customer investment in this study and to explore opportunities to partner with third parties to share costs.

VI. ORDER

IT IS ORDERED that:

1. The Integrated Resource Plan filed by Portland General Electric Company is acknowledged with modifications and exception consistent with the terms of this order and the attached Appendix A.

2. PGE is directed to provide us with a status update, within 60 days of our August 8, 2017 decision, reporting on its development of a revised Action Plan for renewable energy resource acquisition.

Made, entered, and effective OCT 0 9 2017.

Lisa D. Hardie cw — Stephen M. Bloom cw

Lisa D. Hardie
Chair

Stephen M. Bloom
Commissioner

Megan W. Decker
Commissioner

Appendix A

Acknowledged Action Items with Modifications

Action Item – Acquire 135 MWa of cost-effective energy efficiency.

Modifications:

(1) Changes to 2021 capacity need must use the Energy Trust's most recent forecast data;
(2) PGE will provide an update on the Energy Trust's activities and progress on the large customer funding issue in its IRP update in 2018; and
(3) PGE will make available the Energy Trust's energy efficiency forecast data and provide an explanation of their model in the company's next IRP.

Action Item – Acquire 77 MW (winter) and 69 MW (summer) demand response.

Modifications:

(1) Through 2020, acquire at least 77 MW (winter) and 69 MW (summer) of new demand response resource as a floor, while working to reach the demand response high case targets of 162 MW (summer) and 191 MW (winter);
(2) hire a third party to conduct a study for demand response specific to PGE's service territory with results in time to inform PGE's subsequent IRP;
(3) work with Staff to establish, manage, and support a "Demand Response Review Committee" to assist in the development and success of PGE's demand response activities including review of PGE's proposals for demand response programs; and
(4) within nine months (of August 8, 2017), present multiple viable demand response test bed sites to the Demand Response Review Committee, and by July 1, 2019, establish a demand response test bed.

Action Item – Deploy 1 MWa of conservation voltage reduction through 2020.

Action Item – Acknowledge capacity needs of 561 MW, 240 MW of which must be dispatchable, in 2021. Procure capacity via bilateral negotiations and filing of waiver of Competitive Bidding Guidelines. Issue all-source RFP for any capacity needs (including dispatchable capacity) that may remain unfilled after completing bilateral negotiations.

Modifications:

(1) Complete bilateral negotiations, with periodic updates to Staff as to status of negotiations and progress toward completing negotiations of key terms and conditions;
(2) concurrently, work with Staff and stakeholders to scope and launch a regional market study of potentially available resources to be run in parallel with the company's efforts to complete the bilateral negotiations; and

(3) report to the Commission, within four months (of August 8, 2017), the results of the bilateral negotiations and the need for: (a) completing the market study; (b) re-running models and developing a new preferred portfolio using data from the bilateral contracts, the market study, and any other new analyses; and (c) issuing an initial RFP for specific short- to medium-term resources before proceeding with an all-source RFP.

Action Item – Acquire 16 MW of dispatchable standby generation.

Action Item – Submit storage proposal in accordance with House Bill 2193, by January 1, 2018.

Action Item – Perform enabling studies to inform next IRP.

(1) Flexible Capacity and Curtailment Metrics
(2) Customer Insights
(3) De-carbonization
(4) Risks Associated with Direct Access

Modifications: Perform the following additional studies.

(5) Treatment of Market Capacity
(6) Accessing Resources from Montana
(7) Load Forecasting Improvements

Additional Requirements or Recommendations for PGE's Next IRP

Load Forecasting	Conduct ongoing workshops, including consideration of probabilistic forecasts, with interested stakeholders to improve PGE's forecasts. Conduct out-of-sample testing and select models based on these results. Include a technical appendix that describes forecast methodology and contains a list of the forecast modeling assumptions (and explanations) and the model specifications (equations).
Portfolio Ranking and Scoring Metrics	Hold workshops with interested parties to develop a simple and clear set of portfolio scoring metrics, with a focus on using only metrics that have a clear interpretation and robust discussions on the appropriate way to incorporate short- and medium-term options and the relative importance of high-cost versus low-cost outcomes.
Distribution System Planning	Work with Staff and other parties to advance distributed energy resource forecasting and distributed energy resource representation in the IRP process. Work with Staff to define a proposal for opening a distribution system planning investigation.
Transmission	Hold a workshop to explore the issue of transmission and the potential access to higher capacity wind resources in Montana and Wyoming.

ITEM NO. 1

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: August 8, 2017

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** **Upon Commission's Approval**

DATE: July 27, 2017

TO: Public Utility Commission

FROM: JP Batmale

THROUGH: Jason Eisdorfer and John Crider

SUBJECT: PORTLAND GENERAL ELECTRIC: (Docket No. LC 66) Acknowledgement of 2016 Integrated Resource Plan

STAFF RECOMMENDATION:

Staff recommends the Commission acknowledge in part and decline to acknowledge in part Portland General Electric's (PGE or Company) 2016 Integrated Resource Plan. Staff recommends certain actions and additional requirements for inclusion in an IRP update.

SUMMARY OF STAFF RECOMMENDED ACTIONS:

Staff's recommendation as to each Action Item is provided below. The Action Items are discussed in further detail throughout this report. Staff's complete recommendation as to each Action Item can also be found in the box at the end of each Action Item section. Additional recommendations are included in the overview as well.

2013 IRP ACTION PLAN RECOMMENDATIONS

1. **Compliance with Commission ordered requirements from previous IRP**

   Recommendation: Staff finds PGE in compliance with Order No. 14-415. Staff recommends the Commission direct PGE to complete the following in its next IRP:

   - Continue to evaluate non-physical compliance with Oregon's RPS.
   - Continue activities to test and assess the technical and economic viability of converting Boardman to a biomass facility.

2016 IRP ACTION PLAN RECOMMENDATIONS

c. Re-run models and develop new preferred portfolio using data from bilateral contracts, market study and any other analyses.

d. Issue an RFP for specific short- to medium-term resources.

3. **Standby Resources – 16 MW expansion of Dispatchable Standby Generation (DSG):**

   Recommendation: Acknowledge.

1. **Energy Storage – Submit Storage Proposal per HB 2193 by Jan. 1, 2018**

   Recommendation: Acknowledge.

1. Treatment of Market Capacity
2. Flexible Capacity and Curtailment Metrics
3. Customer Insights
4. De-carbonization
5. Accessing Resources from Montana
6. Load Forecasting Improvements
7. Study Risks Associated with Direct Access

1. Load Forecast
2. Portfolio Ranking and Scoring Metrics
3. Distribution System Planning
4. Transmission
5. Bilateral Contracts
6. PURPA Avoided Cost

DISCUSSION:

Issue

Whether the Commission should acknowledge PGE's 2016 Integrated Resource Plan (IRP), acknowledge specific portions of the IRP with or without certain conditions, or decline to acknowledge the IRP.

Applicable Rule or Law

The Commission adopted least-cost planning as the preferred approach to utility resource planning in 1989.[1] In 2007, the Commission updated its existing least-cost planning principles and established a comprehensive set of "IRP Guidelines" to govern the IRP process. The IRP Guidelines found in Order Nos. 07-002 (corrected by 07-047) and 12-013 clarify the procedural steps and substantive analysis required of Oregon's regulated utilities in order for the Commission to consider acknowledgement of a utility's resource plan.[2]

The IRP Guidelines and Commission rules require a utility to file an IRP with a planning horizon of at least 20 years within two years of its previous IRP acknowledgment order, or as otherwise directed by the Commission.[3] Further, the IRP must also include an "Action Plan" with resource activities that the utility intends to take over the next two to four years.[4] The utility's IRP should satisfy the IRP Guidelines and Commission rules for its determination of future long-term resource needs, its analysis of the expected costs and associated risks of the alternatives reviewed to meet its future resource needs, and its near-term Action Plan to achieve the IRP goal of selecting the "portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers."[5] This is often referred to as the "least cost/least risk portfolio."

The Commission reviews the utility's plan for adherence to the procedural and substantive IRP Guidelines and generally acknowledges the overall plan if it is reasonable based on the information available at the time.[6] However, the Commission explains: "We may also decline to acknowledge specific action items if we question whether the utility's proposed resource decision presents the least cost and risk option for its customers."[7]

Also applicable to review of PGE's 2016 IRP is whether it complies with all of the Commission requirements in its previously acknowledged IRP. For example, PGE's 2013 IRP (LC 56) was

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[1] Order No. 89-507.
[2] Order Nos. 07-002 and 07-047. Additional refinements to the process have been adopted: See Order No. 08-339 (IRP Guideline 8 was later refined to specify how utilities should treat carbon dioxide (CO2) risk in their IRP analysis); Order No. 12-013 (guideline added directing utilities to evaluate their need and supply of flexible capacity in IRP filings).
[3] Order No. 07-002 (Guidelines 1(c) and 3(a)) and OAR 860-027-0400.
[4] Order No. 14-415 at 3.
[5] Order No. 07-002 at 1-2.
[6] *Id.* at 1
[7] *Id.*

acknowledged in Order No. 14-415, but the Commission required several activities, in addition to routine resource planning work, for PGE to undertake and include in its 2016 IRP filing. Thus, in addition to IRP Guideline compliance, Staff reviews whether PGE has complied with the Commission's order in LC 56.

Analysis

Procedural History
Prior to filing the IRP, PGE held several public workshops.[8] After filing the IRP on November 15, 2016, PGE held two public workshops. On January 24, 2017, Staff and eight of the intervening parties filed opening comments, followed by a Commissioner workshop on February 16, 2017. In March, PGE was granted an extension to the procedural schedule, and filed its reply comments on March 31, 2017. On April 13, 2017, PGE filed an update to its reply comments adjusting its projected 2021 capacity need from 819 MW to 561 MW. On May 12, 2017, Staff and interveners filed their final comments.

This IRP process was marked by a high level of public involvement and interest. The Commission has received over 7,000 calls, written comments, and/or letters regarding PGE's IRP and Action Plan in the eight months since the IRP was filed. It should be noted that throughout the IRP process, PGE has actively encouraged all stakeholders and the public to provide comments and to participate. Generally the comments fell into the following categories:

- Disagreement with PGE's proposal to acquire or build upwards of 850 MW of new natural gas facilities to fill the Company's 2021 capacity shortfall.
- Encouragement to PGE to meet future energy and capacity needs through the development of renewable generation and enabling technology such as batteries.
- Encouragement to PGE to develop a different long-term plan that would better balance meeting customers' electricity needs while also reducing the Company's greenhouse gas footprint as quickly as possible.

Additionally, the Commission received letters filed as official comments from:

- Oregon Torrefaction: provided an update of the positive technical results and next steps for the biomass pilot at Boardman.
- Columbia Riverkeepers, Oregon Physicians for Social Responsibility, and 350PDX: these groups filed joint comments. They requested an investigation into PGE's safety record at Carty and for the Commission to follow PGE's request to Oregon Department of Environmental Quality to emit higher levels of Volatile Organic Compounds (VOC) at Carty. The request for investigations was referred to Commission Staff working on the current PGE rate case, UE 319.
- Oregon Lawyers for Good Government: recommended not acknowledging the IRP due to several perceived flaws in the IRP analysis.

[8] For more information please see the PGE IRP website: https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning

Given the high level of public interest, the Commission held a special public comment hearing on May 15, 2017, in downtown Portland for the general public to provide comments about PGE's 2016 IRP directly to Commissioners. More than two hundred people attended this meeting in Portland, with about 95 attendees speaking at the meeting. The sentiment at the public meeting generally did not support PGE's IRP as it was currently written.[9]

On June 23, 2017, PGE filed its final reply comments.

A second commissioner workshop was held on July 11, 2017. Staff files this Staff report in advance of the August 8, 2017 Regular Public Meeting on PGE's 2016 IRP.

Framework for Decision-making

IRP Purpose and Principles

Since 1989, the Commission has utilized least-cost planning as the preferred approach to utility resource planning.[10] The Commission's integrated resource planning process remains a vital tool for engagement in a collaborative dialog with utilities over their planned resource investments and strategic direction. Staff agrees with PGE that the four underlying elements of the Commission's IRP planning have withstood the test of time.[11] The Commission's four substantive elements of a least-cost plan are:

1. All resources must be evaluated on a consistent and comparable basis.

2. Uncertainty must be considered.

3. The primary goal is least cost to the utility and its ratepayers, consistent with the long-run public interest.

4. The plan must be consistent with Oregon's energy policy.[12]

Additionally, identifying the energy or capacity need to safely and reliably provide electricity service to customers is a fundamental preliminary step to the planning process. Resource planning is the determination of what particular resource, or mix of resources, can best meet that energy or capacity need at least cost and least risk to the utility's customers. Four basic steps are to: (1) Determine the resource need, (2) Develop multiple resource portfolios, (3) Develop multiple future scenarios, (4) Select the portfolio with the best combination of costs and risk to meet projected customer load.

[9] See Sickenger, Ted. "Ratepayers and activists insist PGE reject natural gas," Oregonian, May 17, 2017, http://www.oregonlive.com/business/index.ssf/2017/05/regulators_and_pge_get_an_earf.html
[10] Order No. 07-002, p. 1
[11] PGE Final Reply Comments, filed June, 23, 2017, p.5.
[12] Order No. 07-002, p.2

The Commission says it best:

> "The primary function of the IRP process is to evaluate the company's load and resource balance for a 20-year planning horizon, and to identify the proper additional resources that might be necessary *to provide reliable service to the expected load*."[13]

The IRP portfolio selection process has been carefully designed to achieve this desired result. The IRP Guidelines require very specific portfolio modeling of all sizes and technologies of resources in a host of probabilistic futures. Out of these futures, the top performing portfolios rise to the top—the least cost and least risk options for meeting the future energy load in order to provide reliable electricity service to customers. Therefore, after identifying the Preferred Portfolio, the utility knows what types of resources to acquire in the quantities necessary to satisfy the projected future customer load.

Following the integrated planning process, a utility may conduct a competitive request for proposal (RFP) process to procure particular resources consistent with the IRP. By contrast, the RFP process is a wholly distinct process with different purposes and different functions. Notably, it is a significantly shorter process, with very limited stakeholder input and oversight as compared to the IRP, and is designed to select the already-determined resource(s).

In sum, the 20-year outlook and two- to four-year Action Plan are integral components of resource planning in Oregon. Nevertheless, the IRP process *is flexible* in that it demands an annual update and a new IRP filing every two years in order to take new information into account. This helps to build confidence that appropriate Action Items are being taken as future uncertainties become less uncertain, and forecasting is not a gamble but rather is an increasingly reliable projection.

Interpretation of IRP Guidelines
PGE expressed concern in its Final Comments that some of Staff's assertions were based on misinterpretations of the IRP Guidelines and particular Commission orders. Regarding Guidelines 1 and 4(n), PGE stated that Staff's assertions directly imply that "the utility must bring the identified resource online during the two- to four-year action plan window."[14] Staff did not assert, nor imply such a conclusion. Staff was trying to explain that the Guidelines require a utility to include in its two- to-four-year Action Plan the resource activities it plans to take to meet system needs, with analysis of the impacts of those decisions over the long-term horizon. Additionally, Staff asserted that the Action Plan addresses near-term identified needs.

[13] Order No. 14-415 at 3 (emphasis added).
[14] LC 66, PGE Final Reply Comments at 8.

Compliance with IRP Guidelines

Elements of PGE's 2016 IRP do not comply with the IRP Guidelines.

Although PGE's 2016 IRP and Action Plan generally follow the Commission's IRP guidelines, the IRP suffers from several important infirmities. In particular, Staff found that PGE's proposed 2016 IRP did not:

1. Consider and evaluate all known resources for meeting load. For example, this is evidenced by bilateral negotiations launched in Q1 2017 at the request of the Commissioners, stakeholders, and Staff, subsequent to the filing of the IRP. (See Guideline 1.a)

2. Compare different resource in-service dates, durations and technologies in its portfolio risk modeling. Instead, PGE used generic proxy resources in its modelling.[15] (See Guideline 1.a)

3. Select a portfolio of resources with the best combination of expected costs and associated risks and uncertainties. This Guideline reflects a fundamental principle of resource planning in Oregon. PGE did not select a portfolio *of resources* with the best combination of expected costs and associated risks. Rather, PGE's use of generic proxy resources resulted in an Action Plan item that relies on an all-source RFP. As a result, the Company may end up with any number of resources to be combined *outside of the IRP process* which will form the portfolio of resources to meet the IRP's stated needs. In short, the Company is substituting the RFP process for the IRP process (See Guideline 1.c).

Intervening parties in LC 66 also found that aspects of PGE's filed IRP did not meet the Commission guidelines. These critiques range from not evaluating and comparing specific resources in the IRP to not properly considering risk and uncertainty. However, the adoption of Staff's recommended modifications for this IRP and certain Action Plan items will serve to remedy the compliance deficiencies.

Compliance with Commission Requirements in LC 56, Order No. 14-415

PGE's 2016 IRP is in compliance with Order No. 14-415.

In addition to the IRP guidelines, Order No.14-415 contained additional action items for PGE to complete as part of its 2016 IRP.[16]

In sum, Order No. 14-415 required PGE to:

[15] Please see PGE IRP Reply Comments March 31, 2017, page 72, on the use of proxy resource capacities instead of contracts of various duration and for not modeling hydro resources.
[16] Order No. 14-415, Appendix A, 1-2.

- Hold a series of workshops with stakeholders (and one Commissioner workshop) to develop a range of multiple portfolios for meeting incremental capacity and energy needs that included specified elements, and workshops on load forecast methodology.
- Analyze shutdown scenarios for Colstrip.
- Include a portfolio level analysis of CVR in the 2016 IRP.
- Conduct a comprehensive analysis of flexible resource options and of analysis of joining the EIM.
- Develop and evaluate multiple RPS compliance strategies.

Staff determined that the additional action items from Order No. 14-415 were either entirely addressed or addressed sufficiently enough in PGE's 2016 IRP that PGE is in compliance with the Commission order. Other stakeholders in LC 66 made no note of PGE missing any action items from Order No. 14-415. However, there are two items Staff would like to continue as part of PGE's next IRP.

ORDER No. 14-415 COMPLIANCE RECOMMENDATION

Staff recommends the Commission find PGE in compliance with Order No. 14-415. Staff also recommends that the Commission continue to direct PGE to complete the following for its next IRP as they could be valuable:

- Continue to evaluate non-physical compliance with Oregon's RPS.
- Continue activities to test and assess the technical and economic viability of converting Boardman to a biomass facility.

Action Plan Discussion

The remainder of this report explores PGE's proposed Action Items, shares the positions of stakeholders and the Company, and provides Staff's recommendation on each item. The chart below summarizes PGE's final Action Plan items. (Attachment A offers a comparison of PGE's original action plan to the final action plan items below).

Area	May 2017 Final Action Plan Items
Demand Side Actions	Energy Efficiency (EE): Acquire 135 MWa
	Demand Response (DR): Acquire 77 MW (winter) and 69 MW (summer)
	Conservation Voltage Reduction (CVR): Deploy 1 MWa Expand AMI Conduct R&D around analytics Develop expansion plan
Supply Side Actions	New Renewables: the addition of 175 MWa of new renewables (equivalent to 515 MW nameplate of new wind resources)
	New Dispatchable Capacity: ~561 MW of new capacity through all source RFP (comprised of 240-415 MW of Dispatchable Capacity due to renewed hydro contract and ~400 MW of Seasonal Capacity)
	DSG: 16 MW
	Hydro Contracts: PGE re-acquired ~135 MW from renewed contract at Wells.
	Bilateral Negotiations: PGE continuing bilateral negotiations with several hydro and thermal capacity resource owners that could potentially satisfy its 2021 capacity need.
Integration	Submit Storage Proposal, per HB 2193, by 1/1/2018
Enabling Studies	Treatment of Market Capacity
	Flexible Capacity & Curtailment
	Customer Insights
	Added several new studies and explorations based on stakeholder comments for the next IRP. They are: ▪ Decarbonization ▪ Accessing resources from Montana ▪ Load forecasting improvements ▪ Study risks associated with Direct Access
Benchmark Resources	Carty Unit 2 – Not considering, but open to benchmark proposals
	Carty Unit 3 – Not considering, but open to benchmark proposals
	Renewables – No determination. Not requesting acknowledgement.[17]
	Storage – No determination. Developing site for RFP later.[18]

[17] PGE IRP Final Reply Comments at 34. "In any event, the Company has not requested acknowledgement of a benchmark resource."
[18] *Id.*

Staff Analysis

DEMAND SIDE ACTIONS

Overview

PGE has proposed three Demand Side Action Items in its 2016 IRP. By 2021 PGE plans to:

- ***DS #1 Energy Efficiency (EE):*** Acquire 135 MWa of energy efficiency.
- ***DS #2 Demand Response (DR):*** Acquire 77 MW of winter and 69 MW of summer demand response resources.
- ***DS #3 Conservation Voltage Reduction (CVR):*** Implement several conservation voltage reduction (CVR) initiatives.

DS #1. Energy Efficiency (EE) Action Item

Overview

The IRP target levels of EE were developed in conjunction with the Energy Trust of Oregon (Energy Trust) through the year 2034. For the Action Plan time horizon, it was determined that ~135 MWa of new cost-effective EE should be acquired in PGE's Preferred Portfolio. PGE used Energy Trust data to explore achieving higher levels of EE in some its other portfolios, but found that portfolios with higher levels of EE did not perform as well and therefore did not select them.

Parties' Positions

Citizens Utility Board (CUB)
CUB's comments on EE focused on the conclusion that it is impossible for PGE and Energy Trust to accurately forecast future EE savings given the current pace of technology changes. CUB also noted in their opening comments that Energy Trust's annual savings continually over-achieve relative to their near- and long-term projections.

Northwest Energy Coalition (NWEC)
NWEC argues that the benefits of EE in reducing the risks and costs associated with RPS compliance and capacity needs are much greater relative to EE's overall costs and thus should be pursued more vigorously.[19] NWEC raises two concerns about EE in this IRP. First, NWEC asserts that the EE forecasting methodology under-represents the potential contribution of cost-effective EE to PGE's near- and long-term energy and capacity needs.[20] Second, NWEC is concerned about interruptions to EE incentives for large customers during the IRP Action Plan time horizon.[21]

[19] *See* the Initial Comments of the NWEC, January 24, 2017
[20] *See* both the Initial Comments of the NWEC, January 24, 2017 and Final Comments of NWEC, May 12, 2017
[21] *See* both the Initial Comments of the NWEC, January 24, 2017 and Final Comments of NWEC, May 12, 2017

Sierra Club
Sierra Club asserts that three flaws in Energy Trust's forecasts lead to PGE underestimating the potential amount of cost-effective EE in this IRP: unrealistically declining savings over time; overstating costs for all achievable savings; and the avoided costs for EE are too low.

PGE's Position
PGE relies on Energy Trust to identify and secure its EE. The 135 MWa of cost-effective EE originally proposed in the IRP Action Plan remained unchanged through the comment period. PGE stated that it could not adopt NWEC's suggested approach to better capture savings from technology development because it was too speculative. PGE asserts the components of EE's avoided costs are set appropriate levels and thus EE's avoided cost is not too low. PGE agrees with NWEC's concern that the Energy Trust may not be able to acquire all cost-effective EE from large customers due to spending limits imposed by SB 838. PGE admits this may pose challenges but has not become an issue yet. Further, PGE's analysis of Energy Trust's 2026 IRP data led them to believe that large customer funding limitations only impacted 0.5 percent of Energy Trust's forecasted savings.

Staff Position and Recommendation
Staff finds that the proposed level of EE in PGE's Action Plan reflects a commitment to cost-effective EE. Staff also agrees with the positions expressed by some of the parties. Staff notes that with the passage of SB 1547, the importance of EE as a resource was further clarified. The law indicates that EE should serve as a priority resource in the resource acquisition plans for any investor owned utility.[22] This sends a clear signal regarding the work to secure all cost-effective EE and influences the recommendations Staff makes.

With regard to stakeholder comments, Staff makes the following observations:

- <u>Incorporating latest EE forecast into IRP</u>: Staff maintains its position that the most up-to-date EE forecast should be incorporated into the IRP. Other resources have been added into the IRP analysis since it was filed in November, including Wells Hydro, a new load forecast, and renewable QF capacity.

- <u>Improved EE forecast:</u> Staff agrees with the stakeholder comments that Energy Trust has historically overachieved its savings relative to its IRP forecasts. In late 2016, as part of Energy Trust's budget review, Staff and Energy Trust management identified EE forecasting as an area for improvement. Energy Trust has embarked on a multi-year plan to improve its forecasting methodology, including the improved incorporation of new technology into EE forecasts. Staff will work with Energy Trust and stakeholders over the next several years to help improve its forecasting methodology.

- <u>Changing EE avoided costs/better understanding of cost and risk impacts of EE:</u> Staff finds the arguments made by Sierra Club and NWEC regarding the value of EE worth

[22] *See* section 19 of SB 1547 which specifies a loading order to utility resource acquisition with EE and DR being prioritized prior to the acquisition of any new generation resources.

exploring. Staff feels an exploration of EE avoided cost methodology, data inputs, processes and integration into the IRP should be conducted by OPUC Staff prior to the next IRP.

Large customer funding: Staff agrees that NWEC was rightly concerned about this issue in its comments. Energy Trust just announced at its July 2017 Conservation Advisory Council meeting that in 2016 it passed the threshold for large customer funding in PGE's service territory. The risk to savings goals and cost-effectiveness during the Action Plan timeframe warrants increased monitoring for market disruptions. To this end, Energy Trust has begun exploring incremental steps to take in 2018 and 2019 to bring large customer incentive spending below the threshold agreed to in 2007. Additionally, Staff notes that any "fix" to this issue would necessitate the collaboration of many stakeholders and possibly even require legislation. For this IRP, Staff recommends that PGE provide a full update on Energy Trust's activities and progress on Large Customer funding in its annual IRP update in 2018.

In conclusion, Staff finds that the analysis supplied by Energy Trust to PGE for their 2016 IRP is consistent with their past methodology and works for this IRP. Staff agrees that some of the observations and criticisms from stakeholders are worth exploring prior to the next IRP.

Demand Side Action DS #1. Energy Efficiency (EE) Recommendation

Staff recommends that the Commission acknowledge PGE's action item of acquiring 135 MWa of EE through the Action Plan timeframe with the following modifications:

- Changes to 2021 capacity need must use Energy Trust's most recent forecast data.
- Provide an update on Energy Trust's activities and progress on the Large Customer funding issue in its annual IRP update in 2018.
- PGE will make available Energy Trust's EE forecast data and provide an explanation of their model in the next IRP.

DS #2. Demand Response (DR)

Overview

PGE has expressed a willingness to work with Staff to implement its ideas to accelerate the pace of DR deployment beyond the amount identified in its Action Plan timeframe. Staff recommends acknowledgement of the DR Action Item with modifications. Most notably, Staff recommends that PGE's proposed levels of DR in this Action Item serve as a floor with more aggressive reach targets.

Parties' Positions

ODOE
ODOE is supportive of Staff's position "to more aggressively develop and acquire demand response assets to address the company's capacity needs." [23]

NWEC
NWEC also finds that PGE's demand response proposal should be viewed as a floor, specifically: "The 69-77 MW range should be seen as a low floor, and reassessment of potential in promising DR segments should commence as soon as possible so that this target can be pushed significantly upward."[24]

CUB
Likewise, CUB supports early aggressive action to procure demand response.[25]

PGE's Position
In their Final Comments, PGE indicates appreciation for Staff's proposal of a Demand Response Test Bed, highlighting that such a concept could help stakeholders understand PGE's challenges.[26] Additionally, PGE suggests including other Distributed Energy Resources and moving the topic of the Demand Response Test Bed to PGE's Smart Grid reports[27] because the "IRP process identifies resource need and evaluates supply-and-demand side options to meet long term needs."[28] Lastly, PGE suggests that it can move beyond the current IRP target of 77MW if regulatory challenges could be addressed.

Staff Position and Recommendation
PGE's position above reinforces Staff's concern that PGE does not currently consider demand response to be a resource; rather, it is still in research stages. To PGE's point about including all DER resources in a test bed, Staff feels that the system, market, and data awareness is not robust enough for inclusion of all DER. The purpose behind Staff's proposal of the Demand Response Test Bed is to rapidly accelerate the development of viable demand response programs and demonstrate its ability to function as a resource. Within this test bed, Staff anticipates already established DERs that can be used to understand the interaction of DERs and DR. To address PGE's concern over cost effectiveness and cost recovery, Staff has shared with stakeholders that it is considering requesting to open a proceeding to explore both items. In the interim, Staff offers recommendations to begin work on the Demand Response Test Bed, development of demand response planning, and resource development.

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[23] Oregon Department of Energy, LC 66 Final Comments, page 5. See also Oregon Department of Energy Opening Comments pages 2-3.
[24] Northwest Energy Coalition, LC 66 Initial Comments, page 5. See also Northwest Energy Coalition Final Comments, page 4.
[25] *See* CUB LC 66 Final Comments, page 6.
[26] PGE's Final Comments LC 66 page 41.
[27] PGE's Final Comments LC 66 pages 41 – 42.
[28] PGE's Final Comments LC 66 page 42.

Staff recommends the Commission acknowledge PGE's Action Item for Demand Response with modifications. Currently, PGE's recommended Action Item pursues only 77MW of winter demand response and 69 MW of summer demand response through 2021. Staff and other parties feel this planned acquisition is conservative at best. Given the analyses produced in this proceeding and PGE's stated need for capacity in the short term, Staff recommends the Commission require PGE to meet 77MW (winter) and 69 MW (summer) demand response megawatts ***as a floor,*** with a reach goal of meeting PGE's own Demand Response High Case of 162 MW (summer) and 191MW (winter). Staff acknowledges the challenges this reach goal presents. Reach goals were used to great effect with Energy Trust when they first began operation. Staff is confident that by working constructively with PGE, Staff and PGE can address the barriers, risks, and concerns highlighted by PGE in their Final Comments. Below Staff outlines the necessary activities to move beyond the currently proposed 77MW (winter) 69MW (summer) demand response targets.

- Studies on Demand Response Potential – IRP Planning
  - To address the issues regarding demand response potential, Staff recommends PGE hire a third party to conduct a study for demand response specific to PGE's service territory with results in time to inform PGE's subsequent IRPs. Staff recommends PGE conduct such studies for each IRP cycle.
  - Additionally, Staff recommends basing the practice and methodology of assessment of technical and achievable cost effective demand response on the energy efficiency assessment work done by the Energy Trust of Oregon and the Northwest Power and Planning Council.
  - Staff recommends PGE submit a draft of its Demand Response Potential study to the Demand Response Review Committee for additional guidance.
- Demand Response Review Committee
  - Staff recommends the Commission establish a Demand Response Review Committee to assist in the development and success of PGE's demand response activities. The Committee could include representatives from organizations such as CUB, ETO, NEEA, ICNU, SmartGrid Northwest, the Northwest Power and Conservation Council Staff, the Pacific Northwest National Laboratory, and the Commission Staff. All programs PGE proposes would be reviewed by the Committee.
- Demand Response Test Bed
  - Staff recommends that the Commission direct PGE to identify multiple geographically defined communities, target multiple customer segments, and consider current infrastructure capabilities, costs, potential penetration levels, and availability of other distributed energy resources as candidates for a Demand Response Test Bed. PGE should identify numerous sites and rank them by

capability, opportunity, and cost. PGE should complete a draft of this effort within nine months of the Commission's order on the 2016 IRP, the results of which would be reported to Staff who would work with PGE to prepare a proposal for filing. Staff's final comments on May 12, 2017 offer additional considerations for PGE.[29]

Demand Side Action DS #2. Demand Response (DR) Recommendation

Staff recommends that the Commission acknowledge, with modifications, PGE's Action Item to acquire 77 MW (winter) and 69 MW (summer) of demand response. Staff recommends the following modifications:

- Direct PGE to acquire at least 77MW (winter) and 69 MW (summer) of demand response *as a floor*, while working to reach the demand response high case targets of 162 MW (summer) and 191MW (winter) as outlined in PGE's IRP.
- Launch the studies on demand response and establish a Demand Response Review Committee.
- Direct PGE, within nine months of a Commission order in this docket, to identify multiple viable demand response test bed sites, present a draft of their findings to the Demand Response Review Committee and establish a Demand Response Testbed no later than July 1, 2019.[30]

DS #3. Conservation Voltage Reduction (CVR)

Staff supports PGE's proposed CVR initiatives and recommends acknowledgement.

Overview
PGE proposed several CVR activities that target a minimum of 1 MWa of energy savings and the expansion of the CVR program through 2020. The activities include smart meter voltage data bandwidth expansion and data analytics R&D.

Parties' Positions, and Staff's Position and Recommendation
Only Staff provided any position on PGE's proposed CVR activities in the IRP. Generally, Staff found the proposal acceptable but would still like to see PGE describe the flexibility in its CVR program in far more detail moving forward. Specifically, PGE should provide an analysis on those distribution feeders which CVR has been deployed. PGE provided no response to this in either set of its Reply Comments.

[29] Final Staff Comments at page XX
[30] *See* Attachment A of Staff's Final Reply Comments in LC 66, dated May 12, 2017.

Demand Side Action DS #3. CVR Recommendation

Staff recommends that the Commission acknowledge PGE's CVR Action Items as proposed in its 2016 IRP. PGE should report on its CVR program in the Smart Grid docket and offer an analysis of those distribution feeders on which CVR technology has been deployed.

SUPPLY SIDE ACTION ITEMS

Overview

PGE proposes three Supply Side (SS) Action Items in its final 2016 IRP:

- ***SS #1 - Renewable Resources:*** Acquire 175 MWa of new renewable energy (equivalent to 515 MW nameplate of new wind resources) through an *Early RPS Procurement RFP* (Early RPS RFP) issued soon after decision on IRP acknowledgement.
- ***SS #2 - Capacity Resources:*** Acquire upwards of 561 MW of new capacity (comprised of 240-415 MW of Dispatchable Capacity due to renewed hydro contracts and ~400 MW of Seasonal Capacity) through an *All Source RFP* issued soon after decision on IRP acknowledgement.[31]
- ***SS #3 - Standby Resources:*** Acquire16 MW of Dispatchable Standby Generation (DSG).

For the purpose of providing background for the Supply Side final Action Items, Staff notes three events that occurred after PGE's IRP was filed in November 2016 that resulted in a reduction to PGE's original projected 2021 capacity need and projected 2029 Renewable Energy Certificate (REC) regulatory compliance need:

- PGE was able to successfully re-negotiate its Wells hydro contract in Q1 2017. This reduced the Company's remaining capacity need by ~135 MW.
- PGE recognized the addition of over 300 MW of solar qualified facilities to its resource mix. This reduced the Company's remaining capacity need by another 52 MW.
- PGE updated its near-term load forecast so that the 2016 IRP load forecast matched the lower load forecast used in PGE's rate case (UE 319). The load forecast revision further reduced PGE's remaining capacity need by an estimated 71 MW.

[31] *See* LC 66, PGE IRP Reply Comments, p. 52 and PGE's April 13, 2017, Letter Updating Figure 5, p. 2.

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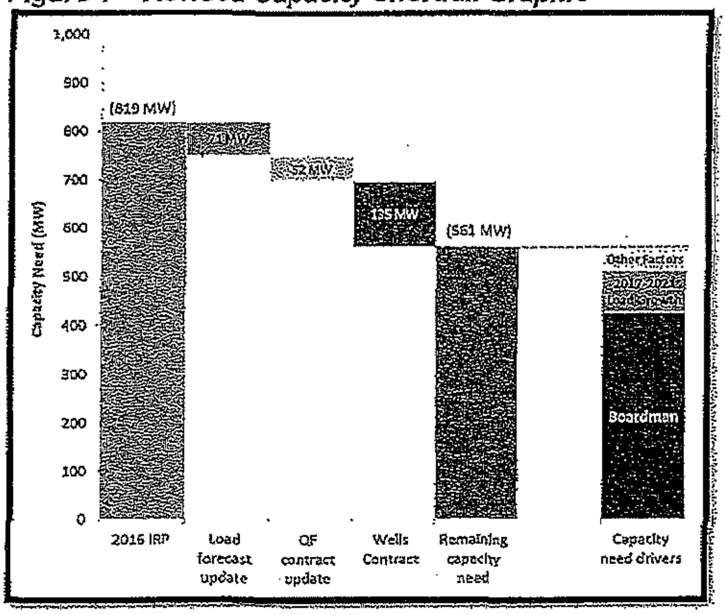
Figure 1 – Revised Capacity Shortfall Graphic[32]



These above-mentioned events had two noteworthy impacts on the 2016 IRP. First, they reduced PGE's 2021 remaining capacity need to ~561 MW. Second, they extended PGE's need for Renewable Energy Certificates (RECs) for Renewable Portfolio Standard (RPS) compliance an additional four years into the future, from 2025 to 2029. Nonetheless, all of the Action Items in PGE's IRP remain largely unchanged. Most notably and concerning to Staff, PGE still continues to seek two categories of large resource acquisitions, one of which is for the primary purpose of meeting a distant regulatory compliance need, not a near-term actual energy or capacity need.

SS #1. Acquire 175 aMW Renewable Resources – Early RPS RFP Action Item

Overview

PGE's action plan states that: "PGE intends to issue one or more Requests for Proposals for approximately 175 MWa of bundled RPS compliant renewable resources, and/or unbundled Renewable Energy Certificates (REC), with a preference for maximizing available incentives for the benefits of customers."[33] As described in detail in the IRP, the referenced "available incentives" refer to Production Tax Credits (PTCs).[34]

[32] *See* April 13, 2017 letter from PGE; revision to Figure 5 in PGE's March 31, 2017 IRP Reply Comments.
[33] See p. 343 of IRP
[34] PGE's Reply Comments at 13.

Description of the Proposed Resource and Need
In its Action Plan, PGE proposes a renewable resource acquisition primarily to meet its 2029 RPS compliance requirement, but also to provide energy and capacity benefits. PGE elected to model a wind resource for the proposed renewable resource RFP and discusses the PTC acquisition in depth in its IRP. PGE does note however that the RFP may produce a different renewable resource(s):

> *"For example, the top-ranked portfolio – Efficient Capacity 2021 – includes the addition of 515 MW of "PNW Wind" renewable resources in 2018. The discussion of renewable resources in Chapter 7, Supply Options, details the assumed characteristics of a PNW Wind resource sited in the Oregon region with an average wind speed at the 80-meter hub height of 6.6 meters per second, with an estimated capacity factor of 34 percent, and technology modeled by GE 2.0-116 turbines. This does not mean that a resource acquisition will be limited to only this specific location, technology type, or timing. In fact the acquisition process will encourage proposals from diverse locations (Oregon, Washington, Idaho, Montana, etc.) and from all RPS compliant resources (wind, solar, geothermal, biomass, incremental hydro, etc.). Resources can be new or existing, physical or REC-based, PGE-owned or contracted. PGE will require each proposal to describe its key attributes and how it meets the needs identified by the IRP."*[35]

In reply comments, PGE's explains that its RPS compliance need for physical resources has been moved out to year 2029, primarily due to updated forecasts and the recent execution of QF contracts.[36] PGE offers modeling demonstrating that the Early RPS RFP Action presents the lowest cost scenario for customers, with NPVRR benefits,[37] and allows PGE's minimum REC bank levels to be held through 2040. PGE provides evidence indicating that a number of circumstances, including the unique nature of Oregon's RPS banking provisions and the imminent expiration of the PTC make the acquisition of a near-term renewable energy resource, even one designed to meet a 2029 need, the lowest-cost, lowest risk option for customers.

> "The Company tested resource procurement timing, size, and technology. PGE also explored additional strategies in its Reply Comments. These analyses identified that, under all of the futures 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."[38]

Through its long-term analysis, PGE contends that the Company has clearly demonstrated substantial ratepayer value to the Early RPS RFP Action — values that are superior to a traditional "just-in-time" approach that by contrast would meet an RPS need closer to when the regulatory need actually arises.

[35] *See* p. 341 of IRP
[36] PGE's Reply Comments at 16.
[37] Id.
[38] PGE's Reply Comments at 13.

Parties' Position

Sierra Club
Sierra Club takes the position that PGE's methodology produces lower-cost wind portfolios that PGE has improperly dismissed.[39] Sierra Club also notes that wind subsides will lapse in the near term, thus the Commission should encourage PGE to issue a renewable RFP.[40]

ODOE
ODOE supports the prioritization of carbon-free resources, including renewable energy.[41]

CUB
CUB acknowledges that PGE may have demonstrated economic savings associated with renewable resource procurement, but is troubled by the fact that PGE plans to procure such resources well in advance of any actual need.[42] For CUB, intergenerational inequity is an important issue because "current customers will see rates increase to pay for a resource that is not needed for several years."[43] CUB is also concerned that PGE's proposal will limit future options to pursue renewable resources that may be more cost-effective, or have superior system benefits.[44]

ICNU
ICNU also opposes early action on several grounds. First, ICNU relies on evidence provided by its expert showing that PGE's proposed early action is costlier than alternatives.[45] Second, ICNU argues that PGE's early action approach represents highly risky and unnecessary hedging.[46] Third, ICNU asserts that the purported benefits of early action are outweighed by substantial risk.[47] Fourth, ICNU argues that the use of unbundled RECs by PGE could eliminate the 2029 need for the early action resource.[48] Finally, ICNU asserts that the early action RFP will increase power costs.[49]

NWEC
NWEC supports early renewables as a least cost, least risk strategy, and takes the position that a larger commitment to renewable resources may represent a lower cost strategy in the long term.[50]

[39] Sierra Club Final Comments on PGE's 2016 Integrated Resource Plan, p.6.
[40] Id. p.13.
[41] ODOE Final Comments, p.5.
[42] CUB Final Comments, p.5.
[43] Id. p.6.
[44] Id.
[45] ICNU Final Comments p.5.
[46] Id. p.6.
[47] Id. p.9.
[48] Id. p.11.
[49] Id. p.12.
[50] NWEC final Comments, p.5.

RNW
RNW believes that PGE selected the wrong portfolio—that a larger renewable resource commitment presents the clear least cost and least risk selection.[51] Because of the NPVRR results, RNW argues that PGE should explore procurement opportunities from 175MWa up to 300MWa, and that PGE's vague concerns regarding integration and operational issues are not consistent with PGE's Wind 2018 Long portfolio.[52]

NIPPC
NIPPC finds PGE has demonstrated a near-term renewable need, exacerbated in part by the expiring PTC.[53] NIPPC states that PGE's benchmark resource presents a geographic diversity danger.[54]

Edward Averill
Edward Averill presents comments highlighting the importance of clean renewable energy supported by storage resources.[55]

National Grid
National Grid objects to PGE's position that large-scale storage is not to be considered as part of the RPS benchmark bid.[56] National Grid contends that large-scale storage could provide numerous benefits to PGE's system in conjunction with PGE's planned early action renewable RFP, particularly with regard to capacity.[57]

Staff's Position

Staff recommends that the Commission not acknowledge the Early RPS RFP Action Item.

Staff first notes that PGE's data and analysis production efforts for the Early RPS RFP Action Item have been very helpful and much appreciated by the parties. Staff commends PGE for its responsiveness, thoroughness, and for the quality of the information PGE has provided throughout this process to Staff and stakeholders. Evaluating the long-term merits of a major resource is challenging, particularly where the need for the resource is not immediate or near-term, but while there are some legitimate factors that could support early acquisition. PGE has addressed this complicated analysis as well as could be expected considering difficulties presented with forecasts twelve years into the future.

PGE has responded to Staff and stakeholder requests, with regard to just the RPS focused portion of the IRP, by completing the following: shortening the analysis timeframe to 20 years, conducting analysis using a revised minimum REC bank strategy, estimating value if COD was pushed out for 2017 wind to 2020, analyzing RPS sizing, and analyzing the value of PTC

[51] Final Comments of Renewable Northwest, p.4.
[52] Id. p.5.
[53] Northwest and Intermountain Power Producers Coalition's Final Comments, p.3.
[54] Id.
[55] Edward Averill Public Comment for docket LC66, PGE IRP, p.1.
[56] National Grid's Final Comments in Response to PGE's Reply Comments, p.1.
[57] Id. p.3-4.

carryforward. All of these requests were completed while PGE managed many other simultaneous responsibilities associated with the broader IRP.

PGE argues that this wealth of analysis supports PGE's central argument in favor of acknowledgement that "...under all of the futures 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."[58]

PGE presented evidence that the opportunity to capture the value associated with the Early RPS RFP Action is uniquely time-limited because the PTCs currently present significant economic value, which may soon evaporate with the non-renewal of the federal tax credit. Further, PGE argues that capturing the PTC value for customers aligns with Oregon's RPS that incentivizes early action.[59]

PGE asserts that its extensive analysis of future scenarios, technology cost and development projections, and their long-term analysis support the conclusion that Early RPS RFP Action is the lowest-cost, lowest risk option for the long term; and that significant projected long-term cost savings justifies Early Action despite the corresponding risks of that result.

In final reply comments, Staff noted that PGE justified the Early RPS RFP Action because their analysis resulted in $173 million in NPVRR value over the life of the asset which represents "less than one percent of the preferred portfolio NPVRR."[1] However, in final reply comments, PGE argues that Staff's NPVRR analysis is too narrow, and that the appropriate value is 6-7 percent of NPVRR:

> "The NPVRR 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.[2]"

As argued by PGE, the analysis, assumptions and data claim a long-term overall cost reduction of 6.7 percent between the Early RPS Action and the Delay Portfolio. Staff would like to clarify two things. First, Staff's assertion about the overall NPVRR benefit of less than one percent was simply one way to put the $173M benefits of a nearly $1B investment into context with the overall size of the preferred portfolio's total NVPRR. It was not to compare portfolios and is just one of many possible ways by which to provide some context for the results provided.

Second, PGE continues to miss a more fundamental point. Claiming one portfolio better represents the best combination of costs and risks – or cost reduction in this case – when both portfolios are based upon the same premise of a need over ten years into the future – is a somewhat meaningless exercise. No matter how much data and analysis is provided, projections of future conditions, laws, technology, prices and other determinative factors over

[58] PGE's Reply Comments at 13.
[59] Id.

twelve years into the future cannot be known today with any degree of certainty such that it justifies such a significant investment. PGE's Early RPS Action proposal is flawed because the analysis is based upon the unquantifiable: the economic, technological, and system conditions of the years 2029-2040 and beyond.

PGE asks the Commission to acknowledge a resource action based upon the unquantifiable: the economic, technological, and system conditions of the years 2029-2040 and beyond. The Commission has been put in this difficult position because PGE's proposal deviates from one of the basic tenants of the IRP process—that proposed major resource acquisitions are acknowledged to meet quantifiable near-term needs.

- *Early RPS RFP Action Upends Proven IRP Planning Principles that Reduce Risk to Customers*

PGE's proposed Early RPS RFP Action runs counter to IRP planning concepts of managing risk, uncertainty, and need. The PUC's IRP process is designed to manage risk by incorporating several key components. These include process components, such as stakeholder workshops and written comment periods, and rigorous substantive analysis that serve to minimize both cost and risk to Oregon ratepayers though stakeholder questioning and analysis.

The least-cost, least-risk principles that the Commission applies to resource acquisition hinge on the primary question of system need, whether for reliability or compliance. Absent a demonstrated need for a resource by the utility, the Commission has recognized that the least-risk and often least-cost plan is to not acquire new resources.

From the point of view of system analysis, risk is limited and managed by examining a wide range of portfolios and through the use of stochastic modeling. The rationale underpinning this approach is the understanding that analyzing a wide variety of candidate portfolios under a wide range of possible unknown but probabilistic futures allows insight into the relative risk profiles represented by different approaches to meeting the utility's system needs.

The IRP guidelines require utilities to perform a long-range planning analysis of at least twenty years and use that long range plan to develop a near-term (2-4 year) Action Plan that embodies the near-term actions necessary to move the utility further down its long range plan. The reason the Commission directs the development of both the long-range IRP and the near term Action Plan is to mitigate risk and to protect ratepayers from possible harm because the ability to accurately forecast future conditions and outcomes diminishes the farther out into the future a projection goes. Although the Commission has recognized that long-term planning is the essential context for shorter term resource decisions, since the promulgation of the IRP guidelines the Commission has not allowed long-term planning to exclusively or primarily drive resource procurement in the near-term when there is no near-term need for the resource.[60]

[60] *See* Attachment B.

The Commission has conceptually agreed with the parties about the difference between risk and uncertainty. For example, parties argued that "probabilities that different outcomes will occur can be reasonably assigned for a risk, but not for an uncertainty" and the Commission agreed with that concept.[61] In other words, near-term risk can be bounded and assigned a probability of occurring, while uncertainty cannot.

PGE's Early RPS Action resource need is so far into the future that risk stops being reasonably calculable and uncertainty is dominant. By contrast, the Commission and utility utilization of "just-in-time" acquisition—where resources are brought online as they are needed and informed by the broader context of a long-term plan—illustrates the rationale underpinning near-term needs being addressed through the Action Plan. The "just-in-time" procurement approach is well-established because risk can be assessed and understood best in the context of customers' near term-needs; whereas uncertainty is inherently unquantifiable. PGE's proposed Early RPS RFP Action does not fit this framework; PGE is asking the Commission to acknowledge a resource action today based upon characteristics and future outcomes that are inherently uncertain.

PGE believes that it has accounted for risks:

> "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, is discussed in detail in Chapter 5 of the IRP and is not precluded by the Action Plan; and qualifying facility (QF) contract growth, 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."[62]

PGE appears to be conflating risk and uncertainty. The long-term factors that PGE has quantified are still highly uncertain; accordingly they do not provide an adequate basis for a decision to commit to a major resource. These distant projections do not represent actionable information sufficient to commit ratepayer funds today for a need that only begins in 2029, and could and could change between now and 2029.

With such a distant need, many unquantifiable factors could become determinative, any one of which could alter the economic case for Early RPS RFP Action before the need for the action emerges. This puts PGE and the Commission in the impossible position of identifying these structural, unquantifiable factors and attempting to understand their future development. For example, in PGE's Final Reply Comments the Company states:

> "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%

[61] Order No. 07-002 at 5.
[62] PGE's Final Reply Comments at 14.

> of electricity demand with clean and renewable resources by 2035 all suggest the Company's clean and renewable obligations, relative to the current RPS legislation, are much more likely to increase than decrease in the future."[63]

Political forecasts or forecasts of future legislative outcomes become crucially important when planning to commit today for major resources not needed until far into the future. This underscores the importance of basing major resource decisions on near term needs; where the factors that could impact a decision are at least more limited, and more subject to an assessment of risk. An IRP process where future political and legislative factors become important subjects of investigation and essential analysis is by its nature steeped in uncertainty, rather than risk.

PGE argues that the IRP process should not be so rigid as to eliminate the capturing of near-term opportunities that are not related to need. However, taking action today in the midst of uncertainty, could preclude future economic opportunity that is real and quantifiable. PGE states that:

> "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 advance. These include: distributed resource planning; material changes to the RPS law; the development of new unforeseen technologies; and the fundamental restructuring of BPA. 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."[64]

PGE's "best available information" in the case of RPS Early Action is not useful to determining economic opportunity, because it is entirely dependent upon the highly uncertain conditions of the distant future. Investing today in a resource that is not needed will probably displace future, near-term need based economic opportunities that we cannot know today, but as PGE notes are likely to occur. In PGE's effort to capture an uncertain opportunity today, some future, better understood opportunity would be foreclosed.

Because the Early RPS RFP Action is so uncertain given the 2029 time frame, it cannot be sufficiently analyzed as to risk. As the need becomes closer to the present, the uncertainty about certain risk events begins to lift and risk can be quantitatively analyzed and the best least cost, least risk actions will become more clear. Past Commission decisions since the promulgation of the IRP guidelines are consistent with this view.[65] In sum, making a significant resource procurement decision outside of the context of near-term need artificially limits the real

[63] PGE's Final Reply Comments at 15.
[64] PGE Final Reply Comments 14-15.
[65] *See* Attachment B.

data and information necessary to make an informed decision and results in a significant uncertainty regarding the least cost, least risk action for ratepayers.

- *Early RPS RFP Action Violates Intergenerational Equity Principles*

Commission approval of PGE's Action Plan that contains the currently designed Early RPS RFP Action has significant implications for ratepayer intergenerational equity. The ratemaking principle of intergenerational equity explains that the period of cost recovery of an investment should correspond to the time it is in use and serving the customers paying for it; said another way, benefits from the new resource investment should accrue to the same set of ratepayers that are assigned the cost of the new resource. In the context of Early RPS RFP Action, this principle is violated because current ratepayers will be assigned the cost of the new resource investments but the primary benefits (REC compliance) will accrue to future ratepayers.

Recognizing the importance of this principle in maintaining just and reasonable rates across generations, the Commission does not generally acknowledge resource acquisitions for purposes that lie outside near-term needs.[66] Staff concludes the same treatment is justified for the Early RPS RFP Action (wind) proposal.

- *The Early RPS RFP Action Hedges Against An Uncertain Need and Effectively Forgoes Alternative Opportunities That Are Least-Cost Least-Risk to Ratepayers*

Staff agrees with PGE that its proposed 175 MWa acquisition of renewable resources that would result from the Early RPS RFP Action would contribute to some of the Company's future capacity need, but the narrative support found in PGE's IRP and subsequent comments indicate the Early RPS RFP Action is proposed for the purpose of satisfying the 2029 RPS regulatory requirement. As a result, Staff finds this Action Item to be a *bundled REC hedge* that places substantial burdens on ratepayers in several ways.

First, by acquiring the resources today to meet the anticipated 2029 regulatory compliance requirement, PGE is locking in RPS compliance at today's costs which may not be lower than future costs. Second, by acquiring a physical asset before it is needed and relying on forecasts to produce the net present-value revenue requirement, PGE assumes that the characteristics of the wholesale energy and REC markets are predictable and dependable for the next 12 years, but Staff does not agree with that this is a reasonable assumption. The uncertainty for both the future cost of bundled RECs and the wholesale market value for RECs increase the further out the forecast goes.

Third, the uncertainty in this proposed Action Item is not only around cost—but it also implicates forgone or lost benefits to customers— PGE's proposed Action Item, if pursued today, could very well eliminate future options that would have provided lower costs for bundled compliance due to technological advancements or market forces. Furthermore, committing to resource acquisition prematurely can also preclude the future acquisition of advantageous resources

[66] Commission Order No. 12-082, Docket No. LC 52, 3/9/12 (proposal from PacifiCorp that the Commission rejected).

which become available due to transmission opportunities, depressed wholesale market prices, and other evolving factors. In short, one serious consequence of taking early action, especially of the magnitude proposed by PGE (nearly $1 Billion), is that it precludes future potential action that could be highly beneficial to ratepayers.

Fourth, PGE's RPS obligation is a function of retail load and its need to fulfill the RPS is partially offset by the level of PURPA contracts (which deliver RECs). Both of these factors will change the ultimate RPS need in 2029 in ways that cannot be known at the present time.

Fifth, the possibility that Oregon's RPS is altered within the 12-year window is possible. In the last ten years, the Oregon regulatory landscape has moved from no RPS obligation in 2006, to a target set by ORS 469a, and recently by SB 1547 to a compliance target of 50 percent by 2040. Future legislative actions or inevitable market forces may result in a reality in which renewable resources are the economic choice in a resource planning environment. There could be a future in which an RPS is no longer needed because renewable resources become the first choice as least cost least risk resources. In fact, PacifiCorp's 2016 IRP reflects this premise—mandated renewable resource acquisition could be unnecessary in the future due to simple economic decision-making where renewable energy is the lowest-cost, lowest-risk energy or capacity resource.

Indeed, other policies or regulatory changes could evolve in the intervening years altering the relationship between the utility and its customers concerning the development of generation assets.

In sum, PGE's Early RPS RFP Action should not be acknowledged because it assigns the risk of the proposed bundled REC hedge entirely to ratepayers, substantially before RPS action is needed.

SS #1. Early RPS RFP Action to Issue RFP(s) for 175 MWa New Renewables Recommendation

Staff recommends that the Commission not acknowledge PGE's Action to issue RFP(s) for 175 MWa New Renewables.

SS #2. Issue RFP(s) for up to 415 MW of Dispatchable Capacity and 400 MW of Flexible Capacity Resources for 2021 Capacity Need

Overview

PGE's Action Plan seeks to issue an RFP dispatchable capacity between 240 to 415 MW.[67,68] PGE's 2021 capacity need was revised down in April 2017 from 819 MW to 561 MW due to securing the capacity contribution of the recently signed Wells hydroelectric project contract and other factors.[69]

The proposed RFP for dispatchable capacity is PGE's primary supply side action. It is designed to fill the Company's 2021 capacity need and to meet a portion of PGE's flexible capacity requirements.[70] PGE's annual flexible capacity need was not revised downward by the re-signing of the Wells hydroelectric project. PGE claims its overall flexible capacity remains at approximately 400 MW because it must be able to accommodate the increase in penetration of variable energy resources in the future.[71]

Pursuant to IRP Guideline 13 (requirements for Resource Acquisition), PGE identified a general, all source RFP (All Source RFP) as the acquisition strategy to secure their dispatchable capacity resource.[72, 73] Specifically, PGE proposes to:

> *. . . issue an RFP to procure the renewable and capacity resource attributes identified in the IRP Action Plan by specifying the electric and environmental characteristics described in the IRP. There are a number of technologies with such attributes that would be eligible to submit proposals to meet PGE's need. The Commission and stakeholders would, consistent with the Commission's RFP Guidelines, review the RFP design in the RFP docket. PGE believes this approach is consistent with the IRP/RFP structure adopted by the Commission in its IRP and RFP Guidelines.*[74]

Notably divergent from past practice, PGE will select those least-cost, least-risk resources that most closely match the performance and environmental characteristics of what was modeled as a capacity resource in the IRP, but not based on any specific resource per se as is the customary practice.[75]

Parties' Positions

There were many comments on PGE's All Source RFP action item to meet its capacity need. Most parties' comments could be generalized into four categories:

- PGE did not properly consider short- to medium-term resources;
- The IRP is not specific enough about the particular resource needed;

[67] PGE IRP Final Reply Comments at 28
[68] For a full definition of dispatchable resources, please see PGE 2016 IRP at 146.
[69] *See* description and Figure.1, at 7 and 8; source: PGE Update to 3/31/17 Reply Comments.
[70] PGE 2016 IRP at 343.
[71] PGE 2016 IRP at 171 and 344
[72] 07-002, Guideline 13.a at 22.
[73] *See* LC 66 PGE Reply Comments at 13, for a concise description of the RFP strategy
[74] *See* LC 66 PGE Reply Comments at 9.
[75] *See* LC 66 PGE Reply Comments at 9 March 31, 2017.

- Decisions by PGE in its analysis partially drive the 2021 capacity need;
- The above deficiencies in analysis can be remedied by sequencing events prior to the proposed RFP.

Staff finds that PGE's analysis demonstrated some mid-term capacity need. What PGE does not do is specify a portfolio of least-cost, lowest-risk resource(s) to meet its 2021 capacity need. By using proxy resources and generic capacity, only certain characteristics of the potential portfolio of resources were identified by PGE in the 2016 IRP.

Several parties, including Sierra Club, CUB, and ICNU, expressed concern that the IRP only identified the desired performance and environmental characteristics of a capacity resource, rather than a specific resource itself, therefore, the IRP did not comply with Commission guidelines. Specifically Sierra Club stated:

> *Instead of selecting a specific set of resources to acquire, PGE claims that it will procure an unspecified mix of resources with the goal of achieving renewable portfolio standard (RPS) compliance and resource adequacy. This lack of specificity is simply not acceptable in a long-term planning case. PGE is obligated to produce an IRP that evaluates "all known resources" and tests "various operating characteristics, resource types, fuels and sources, [and] technologies." In this IRP, however, PGE has merely gestured at evaluating actual resources with realistic costs and performance data.*[76]

As summarized below, several parties also stated that the IRP did not properly consider short- to medium-term resources. They noted that short- to medium-term contracts provided optionality in the face of tremendous uncertainty in the energy market and could help PGE avoid committing of ratepayer dollars to irreversible, long-term resource decisions that very well may not be the least cost path in only a few years, and is certainly not the least risk path today.

NIPPC
NIPPC said that the IRP failed to provide sufficient information regarding the costs, benefits, and risks associated with different types of capacity resources.

CUB
CUB believes that PGE should first issue an RFP for shorter term resources prior to issuing an RFP for a 30-year resource, specifically proposing that Commission acknowledgement of an RFP for a long-term resource should include a requirement that the Company first issue an RFP for resource commitments between 2 and 15 years in length.

ICNU
ICNU agrees that the Company is likely to have a capacity need in 2021 but that the amount of the need is highly dependent on market access which, in ICNU's and other Parties' opinions, has not been adequately addressed. ICNU recommends the Commission decline to

[76] *See* Sierra Club, Initial Comments at 3

acknowledge the RFP for capacity until the Company can demonstrate (a) the extent to which it can rely on the market to meet its remaining capacity needs and (b) that the remaining capacity need must be met with dispatchable capacity as opposed to other sources of capacity.

Sierra Club
Sierra Club takes the positon that PGE should explore shorter term commitments to fulfill any near-term capacity need given that the 2021 capacity need originally proposed by PGE has already decreased since the IRP was first filed. This measured approach would preserve optionality over the long term, as opposed to committing our energy future to significant long term resources.

National Grid
National Grid said that short- and medium-term market purchases can serve as an effective bridge to an environmentally-friendly long-term solution, and that it believes that closed loop pumped storage has the ability to meet all of PGE's system needs for flexibility.

NWEC
NWEC recommended that the Commission conditon acknowledgement on a precise sequencing of procurement actions starting with bilateral negotiations of hydro, then an RFP for up to 300 MWa of renewables, and then an RFP for demand side resources. After these three actions are completed, the analysis of system capacity need should then be refreshed with all new system assumptions.

RNW
RNW supports the approach of PGE first pursuing bilateral hydro contracts, and then issuing a renewable resource RFP with (1) hydro bilateral contracts, and then (2) thermal bilateral contracts in order to meet PGE's remaining capacity needs.

<u>PGE's Position</u>

PGE plans to address its 2021 capacity need through an All Source RFP. Rather than select a specific resource, the All Source RFP will instead state the performance and environmental characteristics any potential resources must meet to be selected. PGE found that given "the similarity of the results across portfolios…it is not appropriate to constrain the types or quantities of future resource procurement to the exact resources modeled in the preferred portfolio."[77]

Many parties expressed concerns about this approach and that the IRP is not specific enough in identifying the type of resource to be selected in the RFP, PGE explains that as long as the resources acquired through the RFP has the performance attributes identified in their preferred portfolio, *Efficient Capacity 2021,* than PGE is following the tenants of Least-Cost planning.[78] PGE stands behind its position that it designed the 2016 Action Plan to be flexible in resource procurement:

[77] PGE IRP at 344.
[78] PGE Reply Comments at 7.

The Action Plan maintains flexibility in the types of technologies that can be acquired under an RFP, but provides specificity as to the electric and environmental attributes that will be sought in an RFP. PGE has not prejudged the technologies that might be acquired under the RFP, but has provided guidance in the Action Plan as to the nature of the resource need and the electric and environmental characteristics that are necessary to meet the need.[79]

And further,

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. PGE has gone beyond the requirements of the Guidelines by providing additional specificity about the resources it will seek in the RFP.[80]

As to the recommendation by parties to consider short- to medium-term resources, PGE states that it attempted to model and include such resources to the extent possible. However, the challenges related to cost structure, duration and other terms made modelling too difficult.[81] Further, PGE characterized the use of shorter-than-life resources for evaluation in the IRP in a generic manner to be speculative and inappropriate, and was reflective of the "free rider" thinking that lead to the Western energy crisis of 2000.[82, 83]

To address claims by the parties that certain changes made in this IRP, such as modelling limited or zero access to the market during the peak or adopting a new planning reserve margin methodology, increased PGE's capacity needs, PGE asserts that all of these changes were done to improve the planning for least-cost, least risk resources and reliability done through the IRP. For example, PGE explains that switching to a new methodology for determining planning reserves margins was necessary given concerns raised by stakeholders in 2013 about assessing the capacity contribution of higher level of variable resources.[84]

Finally, PGE expressed concern regarding several parties' recommendation as to the sequencing and completion of specific events prior to issuing an All Source RFP. However, in June, PGE stated that it would attempt meet its 2021 capacity needs by acquiring resources through bilateral negotiations and, if needed, an RFP process, while maintaining a prudent exposure to the spot market.[85] Nevertheless, because PGE is unsure of the outcome and timing of the bilateral negotiations and any other RFP (e.g., NWEC's renewable RFP for capacity), PGE also states that it wants to file the All Source RFP right away. That way if the Company is

[79] PGE Reply Comments at 8
[80] PGE Final Reply Comments at 34
[81] PGE Reply Comments at 76.
[82] PGE Reply Comments at 78-79
[83] PGE Final Reply Comments at 26
[84] PGE Reply Comments at 41
[85] PGE Final Reply Comments at 26

not able to obtain sufficient capacity through the bilateral negotiations in order to meet customer's capacity needs in 2021 it can already have the All Source RFP underway.[86]

Staff's Position and Recommendations

- *PGE has a capacity need in 2021 that will likely require additional generation; however, Staff recommends that additional actions must be taken prior to issuance of an All Source RFP*

Despite concerns raised by stakeholders regarding the methodology behind PGE's 2021 capacity need, Staff acknowledges that PGE, in all likelihood, has a capacity need of upwards of 560 MW. PGE has been clear that if bilateral negotiations result in additional dispatchable capacity, PGE will reduce their remaining, annual, dispatchable capacity need and will update the Commission in a report.[87] To this end Staff appreciates how PGE prioritized its resource acquisition approach in its June comments.[88]

Staff notes that there could be another event that further impacts PGE's capacity need. According to filings in UM 1854, PGE now has over 417 MW of solar power now in queue from proposed PURPA qualified facilities (QF). If fully implemented, these projects would represent a near-term doubling of the contracted QF solar power currently in PGE's portfolio.[89] The exact impact on PGE's remaining capacity needs from these projects cannot be determined at this time. Staff understands that they will likely reduce PGE's overall capacity need. Staff notes that PGE has motioned the Commission for interim relief from contracting with many of these new, proposed Solar QF projects.[90]

- *Staff finds that PGE's approach in not naming a specific resource does not meet the minimum requirements set forth in the IRP guidelines.*

Staff finds that PGE's approach of not specifying a resource—but rather a set of characteristics—might meet the technical wording of the IRP Guidelines 4.e., 4.h, 4.l and 4.n, but this approach improperly shifts portfolio development from the IRP process to the RFP process. Staff finds PGE's assurance that the RFP will support a broad range of resources and be "designed so that the portfolio effects between incremental resources can be determined," to be troubling as PGE could not produce this analysis in the IRP modeling process, except for large resources like natural gas plants.[91] Moreover, such an approach ultimately denies the Commission the ability to determine if an RFP-procured portfolio of resources presented the best combination of cost and risk to ratepayers because the Preferred Portfolio that was selected in the IRP process has no specified resources to procure in the RFP. The first major step in resource planning is skipped in this scenario. In effect, acknowledgment of such a broad

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[86] PGE Final Reply Comments at 28.
[87] PGE Final Reply Comments at 27.
[88] *Id.*
[89] *See* UM 1854, PGE's Motion for Protective Order, 7/13/17.
[90] *See* UM 1854, PGE seeks to change the PURPA standard pricing eligibility cap for solar QFs and to lower the standard price for solar QFs.
[91] PGE IRP at 344.

range of resource choices becomes rather meaningless, as any set of acquired resources might qualify as least cost/least risk for ratemaking purposes without any assurance that that set meets the standard.

Further, the Commission has expressed that the guidelines "incorporate what we minimally expect from an IRP. We urge the utilities to provide more, rather than less information."[92] From Staff's perspective, the IRP's suggested approach to the All Source RFP presents less, rather than more, information.

- *The IRP's All Source RFP rests on three key assumptions that do not hold water under examination.*

Staff finds the following implicit assumptions must be correct in order for the All Source RFP to result in a portfolio of resources that best balances costs and risks:

- The IRP considered all known resources;
- A large, representative sample of the available resources in the region will compete in the RFP; and
- PGE has the tools and information to properly assess and compare different resources.

These assumptions have not been met given the analysis and tools presented by PGE. The IRP Guidelines direct utilities to consider all known resources for meeting need.[93] Staff recognizes that PGE was relatively thorough in much of its IRP analysis and in response to comments, but all known resources were not considered in the IRP analysis based on the following.

First, the breadth and depth of parties willing to engage in bilateral negotiations with PGE for both hydro and thermal resources indicates that the IRP did not sufficiently explore these existing resources (i.e., the market) during portfolio development.

Second, PGE maintains that it has an incomplete picture of the market. To address this, PGE plans to launch a full study of the market *after* the All Source RFP is issued and completed. Staff and other stakeholders continue to find this timing backward.[94] An RFP will not provide a complete picture of the marketplace, but only insights into the services, costs, terms and conditions associated with those resources *that choose to participate* in the RFP. By way of example, data not found in this IRP or revealed explicitly in an RFP but that can be found in a comprehensive market study that would materially impact the consideration of resources includes:

- The depth and costs of resources, especially during peak hours at COB and Mid-C;

[92] *Id.* P. 12
[93] Order No. 07-002, p. 3.
[94] CUB Opening Comments at 7.

- The impact of surplus renewable energy from California and how to best plan and operate resources around it;
- Regional utility resource and energy surplus/deficiencies in a given year;
- Reserve requirements and best balancing intermittent resources within the CAISO EIM.

Therefore, performing the market study, for a need arising in 2021, prior to issuing an All Source RPF makes practical sense.

Third, multiple parties stated that the IRP does not adequately consider the use of short- or medium-term contracts to meet the Company's needs. Staff suggested that PGE provide a portfolio-like analysis of at least one such strategy. Further, at the February 2017 IRP workshop, each of the Commissioners asked questions about the lack of short- to medium-term resources in the IRP analysis.

In short, PGE stated that it could not fully consider resources of various duration in the IRP and that it would be more appropriate to do so in the RFP.[95] This position directly contradicts a finding from the Commission in Order No. 07-002 when it adopted the IRP guidelines:

> *The Coalition responds that the duration of a resource is important during IRP evaluation, as resources with shorter lead times and tenure provide optionality . . . Staff Agrees and notes the benefits of market purchases demonstrated in PacifiCorp's last IRP . . . We conclude that the lead-time and duration of a resource is important and should be examined during the IRP process. Such analysis will help the utility to determine the value of maintaining flexibility versus committing to long-term resources.*[96]

PGE admittedly experienced difficulty analyzing and comparing resources of various duration in the 2016 IRP. Thus, PGE limited the modelling of resource duration in the IRP to between 25 and 35 years.[97] Consequently, the IRP could not have properly assessed short- to medium-duration contracts because they are less than PGE's modeled durations between 25 and 35 years. Unfortunately, PGE provides little discussion of the comparative risks between resources of various duration.

PGE's lack of consideration of short- to medium-term resources throughout the IRP process, especially given the number of comments and the value placed on considering these assets in the IRP guidelines, conflicts with the conclusion that PGE considered all known resources in their analysis.

- o *An All Source RFP for capacity based on this IRP favors acquisition of new, long-duration, thermal resources which has the consequence of committing ratepayer dollars to a 30 year resource.*

[95] PGE Reply Comments at 72.
[96] Order No. 07-002 at 4.
[97] PGE IRP at 212.

PGE lists several generation technologies eligible to bid into its planned capacity RFP.[98] Eligible, dispatchable generation, like biomass, energy storage, and geothermal, are not competitive according to the IRP.[99] The only dispatchable generation technology that could hypothetically compete with natural gas on cost is hydro generation. However, as PGE pointed out in both 2014 and in 2017, hydro resources will not bid into an RFP.[100] Thus, while PGE asserts that its proposed All Source RFP would be open to all eligible resources, in reality, the All Source RFP process would only surface natural gas generation as a possibly competitive resource.

Further, PGE does not know exactly when the bilateral negotiations for hydro and thermal resources will be completed.[101] There is a likelihood that the RFP would close prior to resolution of the bilateral negations.

Based on the concerns regarding PGE's analysis discussed above, new, long-duration dispatchable generation resources have an implicit advantage given (1) the approach and available tools used to create the IRP and (2) the ease with which data on long-duration, dispatchable generation resources fit into PGE's IRP approach and tools. To remedy this deficiency, Staff maintains that any acquisition of capacity should first consider short- to medium- term resources.

In sum, without a different procurement approach to determine the availability, costs, and risks of hydro resources and a different set of tools and/or analysis for resources of short- to medium-duration, PGE will be unable to explain how selected resources appropriately balance cost and risk relative to other resources. (See requirements of Guideline 1.c).

Further, it is reasonable to expect that the All Source capacity RFP process will result in procurement of a new, long-duration, natural gas facility if other actions are not taken prior to this proposed RFP. If Staff was confident that the information necessary to determine whether a new, long-duration, natural gas facility was actually least-cost/least-risk relative to the known alternatives available it would not be opposed to such a facility. However, such information is not currently available in the IRP.

- *The Commission's IRP guidelines value maintaining flexibility relative to committing to long-term resources.*

As stated previously, the IRP structure and the past practices of the Commission work together to place a premium on "just-in-time" decision making. This practice serves ratepayers well in that it defers large, resource and capital intensive decisions until they are necessary to provide electricity service to customers.[102] The concept of optionality implies that all available and

[98] PGE Reply Comments at 9.
[99] PGE IRP at 212, 313, 752.
[100] PGE Reply Comments at 12.
[101] PGE Final Reply Comments at 29.
[102] Order No. 07-002 at 4

relevant options are known and compared against each other prior to a resource acquisition decision.[103]

While PGE admittedly has a capacity need in 2021, the analysis and chosen resource procurement pathway serves to limit the options available for evaluation and comparison. Moving from the current IRP to an All Source RFP without intermediate actions effectively deprives the Commission of the information necessary, and confidence in the underlying analysis, to assess the reasonableness of the resources selected for PGE's preferred portfolio. Parties to this docket continue to point to the high degree of uncertainty in regional markets and rapid technological developments as reasons for why, at this point in time, PGE should consider commitments that are shorter than the life of a long-term resource.

Throughout the process, PGE has also stated that the benefits of term-limited contracts are "dependent on speculation" and are not "riskless."[104] Specifically that the parties' arguments in favor of shorter-term contracts "rely on speculation that future resource cost and risk characteristics will be favorable relative to resources available today."[105] This argument is the converse of the premise PGE relies on—that today's resources have cost and risk characteristics lower than the resources available in the future. However, the important difference between the two is that PGE's speculation results in committing ratepayer dollars to a resource lasting 30 years for a need that is still four years out and could be filled by alternative less cost and less risk options that have still not been fully explored. Staff's approach is consistent with the Commission's directive to protect ratepayers and ensure that reliable electricity service is provided to them at least cost and least risk.

- *Staff's suggested sequence of events prior to issuing an All-Source RFP compensates for deficiencies in the 2016 IRP and PGE's decision to utilize an RFP for selecting LC/LR resources rather than the IRP itself.*

PGE has stated that the data on the costs and characteristics of new, natural gas generation facilities is robust and well established.[106] Conducting ongoing, least cost, least risk comparisons of the data PGE receives as it moves through the bilateral negotiations, market study and the RFP for short- to medium- term dispatchable resources to what is known about the new resources like the GE 7F.05 simple cycle combustion turbine is not difficult to accomplish and more importantly, affords PGE the ability to make a reasonable determination as to resource selection prior to issuance of an All Source RFP.

[103] *Id.*
[104] PGE Final Comments at 31.
[105] PGE Final Comments at 31.
[106] Source.

SS #2. Issue RFP(s) for up to 415 MW of Dispatchable Capacity and 400 MW of Flexible Capacity Resources Recommendation

Staff recommends that the Commission acknowledge PGE's 2021 capacity need of up to 561MW, but decline to acknowledge the issuance of an All Source RFP to fill the remaining capacity need until the following actions have been completed in the order listed below:

1. Complete bilateral negotiations and report to Commission.
2. Complete market study.
3. Re-run models and develop new preferred portfolio using data from bilateral contracts, market study and any other analyses.
4. Issue an RFP for specific short- to medium-term resources.

SS #3. Standby Resources Action Item

Overview
PGE proposes to acquire 16 MW Dispatchable Standby Generation (DSG). "PGE will pursue expansion of Dispatchable Standby Generation (DSG) by 16 MW to meet standby capacity needs (non-spin). PGE will also pursue actions (such as customer site development and contract negotiations) to achieve additional annual standby targets, if needed beyond 2020."[107]

Parties' Position
No parties oppose PGE's Standby Resources Action Item.

PGE Position
PGE's DSG program partners with commercial and industrial customers with a need for emergency, standby generation greater than 250kW. Typically, these are diesel generator resources. DSG resources are used to help meet non-spinning reserve requirements; PGE identifies a benefit from the fact that generators are located throughout PGE's service territory and that they reduce risks associated with transmission and fuel supply.[108]

Staff Position and Recommendation
Staff recognizes the value of the Company's DSG program and encourages PGE to maintain this program as a part of its resource strategy.

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[107] *See* PGE IRP at 344.
[108] *See* PGE IRP at 194.

Supply Side Action SS #3. Standby Resources Recommendation

Staff recommends that the Commission acknowledge PGE's Supply Side Action Item to obtain a 16 MW expansion of DSG.

INTEGRATION ACTIONS

IA #1. Energy Storage

Overview

Pursuant to House Bill 2193, and not later than January 1, 2018 PGE will submit one or more proposals to the Commission for developing a project that includes one or more energy storage systems that have the capacity to store at least 5 MWH of energy.

Parties' Positions

National Grid commented that it was concerned that PGE was no longer pursuing an energy storage benchmark resource. CUB commented that PGE was not aggressively pursuing energy storage beyond what is required in HB 2193 nor forecasting its broader adoption in the IRP, despite a number of system peaking and operational benefits.[109]

PGE's Position

PGE states that it has not made a determination to remove energy storage from any potential RFP but has chosen not to submit energy storage bid for a "site specific, self-build option." PGE also states in the IRP and in its reply comments that it put substantial effort into modeling energy storage resources as a resource in its IRP portfolios. PGE stated that successfully integrating storage into the IRP portfolios and models represented a large technical hurdle and opted not to do so in this IRP. PGE is also developing an evaluation framework for energy storage procurement decisions and identifying analytic needs for future resource decisions.

Staff Position and Recommendation

Under UM 1751 the Commission addressed PGE's compliance with HB 2193's mandate for a minimum amount of energy storage in place by January 1, 2020.[110] Staff notes that PGE's difficulty in modeling energy storage for this IRP is problematic such that PGE was unable to utilize them as resources when developing portfolios to model in the IRP.

We appreciate PGE's commitment to continue engaging stakeholders on this issue of modeling and valuing energy storage applications from both its own planning exercises and those by other utilities. For the next IRP, Staff recommends that the Commission direct PGE to incorporate storage as resource options within IRP modeling, including distribution level storage opportunities. The utilities recently submitted draft system evaluations in the Commission's current storage dockets. These evaluations show greater value can be extracted from a storage resource when it can serve the most use cases. Often this means siting the resources on the

[109] *See* CUB Opening Comments, January 24, 2017, pgs. 9 – 10.
[110] *See* UM 1751, Order No. 17-118, issued March 22, 2017.

distribution system. This should not however negate the responsibility of the IRP team from also considering supply side storage such as pumped hydro. Staff recognizes that as currently constructed PGE's IRP model may not be able to incorporate storage as a resource because too often a storage resource's capacity is too small to reach the modeling threshold. However, short comings in modeling should not be an excuse to not thoroughly consider a new promising resource. PGE's draft system evaluation presents a promising pathway to model the value of energy storage resources. As this approach become more refined and the utility has greater confidence in its accuracy we suspect the utility and its modeling will view storage as more valuable therefore a more viable investment. Staff foresees an update to this potential evaluation study as being a key source for modeling assumptions for energy storage in the next IRP.

IA #1. Energy Storage Recommendation

Staff recommends that the Commission acknowledge the energy storage action item of acquiring energy storage to meet HB 2193's 2020 mandate and direct PGE to incorporate energy storage as resource options within the next IRP.

ENABLING STUDIES

ES #1. Enabling Studies to inform next IRP

Overview

PGE proposed the following enabling studies to inform the next IRP:

- Treatment of Market Capacity
- Flexible Capacity and Curtailment Metrics
- Customer Insights

PGE also noted in their reply comments issues they would be studying with stakeholders or launching a study of:

- De-carbonization
- Accessing resources from Montana
- Load forecasting improvements
- Study risks associated with Direct Access

Parties' Position

In addition to the studies identified above, ODOE requested that PGE launch two additional studies. First, PGE should launch a study to evaluate the costs and benefits of joining the

Western ISO. ODOE also requested that PGE launch a study to evaluate the location-specific benefits to PGE's transmission and distribution system through the strategic deployment of distributed energy resources. NWEC saw the need for a comprehensive market study. Otherwise, there were no other party comments on this topic.

PGE's Position
PGE did not say they were opposed to any of the studies suggested above. They did caution that a market study would be inferior to an RFP and that it should take place after the RFP is complete.[111]

Staff Position and Recommendation
All of the proposed studies, and those recommended by Staff, support PGE in developing a stronger IRP. Staff appreciates ODOE's suggested studies as they are timely and could impact important near-term decisions by PGE. Staff believes that ODOE's reference to the Western ISO is meant to refer to CAISO.

ES #1. Enabling Studies Recommendation

Staff recommends that the Commission acknowledge PGE conducting all of the studies proposed by PGE, ODOE and Staff.

GENERAL IRP RECOMMENDATIONS

G #1. Load Forecast

Overview
PGE forecasts that about 90 MW of its 2021 capacity need is due to growth in load between 2017 and 2021. PGE forecasts that its load will grow faster after 2021, when PGE forecasts load growth of 1.2 percent per year from 2022 to 2050. Broken out by sector, PGE forecasts long-term growth of 0.6 percent per year for residential loads, 0.9 percent per year for commercial loads, and 2.6 percent per year for industrial loads. PGE also considers a "high growth" scenario of 1.7 percent annual growth and a "low growth" scenario of 0.6 percent annual growth. In its Reply Comments, PGE revised its capacity need down by 71 MW due to reductions in its load forecast made after filing the IRP.

[111] PGE's Final Reply Comments at 32.

Parties' Position

ICNU
ICNU points out that economic forecasts for Oregon have decelerated from the forecasts used by PGE in developing its IRP and ICNU recommended that PGE update its forecast to include current Oregon Office of Economic Analysis (OEA) data.

CUB
CUB notes that PGE does not include explicit adjustments to historical loads to account for community solar, customer-sited solar, or the potential for acceleration in adoption rates of customer-sited solar.

PGE's Position

PGE justifies its load forecast methodology and outcomes based on the use of estimated "historical" relationships between economic variables and energy deliveries that PGE states are "structural" and "fundamental."[112] PGE also defends its methods based on a review of its methodology by a third-party consultant, and based on economic and population forecasts for Oregon. PGE states that Portland "is a relatively unique area for economic growth compared to the rest of the US."[113]

PGE states that the revised OEA data shows "only minor changes to the trajectory of economic inputs."[114] PGE states that trends in customer-sited solar are already embedded in historical load data.

Staff Position and Recommendation

PGE's current load forecast should not serve as the basis for long-term investments in new generating resources.

Staff has a variety of concerns with PGE's load forecast and has stated so consistently throughout the IRP process. Staff is primarily concerned that PGE has not given sufficient consideration in this IRP to the possibility that load may not materialize as PGE forecasts. PGE presents "high" and "low" growth cases that are derived from an ad-hoc method that lacks statistical justification, as opposed to using either a formal statistical method or a set of assumed circumstances that comprise each scenario. Staff suggested that PGE construct a 95 percent confidence interval for its forecast. PGE did not provide probabilities for its high/low cases, nor did PGE provide a probability associated with its expectation that its load will fall within these "jaws." Staff noted that, since the release of PGE's forecast in its 2013 IRP, PGE's monthly energy deliveries have fallen outside of its forecast jaws more often than not.

[112] PGE Reply Comments at 30-31.
[113] PGE Final Comments at 35.
[114] PGE Reply Comments at 32.

Staff illustrated its concerns with PGE's approach using regional comparisons and noted that the growth that PGE forecasts greatly exceeds the growth expected by the other Pacific Northwest utilities who serve larger urban areas (i.e., Puget Sound Energy and Seattle City Light). PGE's "low" growth case is *higher* than even the mid-range forecasts for both of these utilities. PGE states that these utilities are not reasonable comparisons for PGE because the industrial growth in PGE's service territory is not likely to be similar to the industrial growth in Seattle City Light's or PSE's territory. Staff remains very uncertain about PGE's industrial growth and growth rate overall and finds the distinction posed by PGE misses the larger point that Staff is concerned that PGE presents its load growing so much while nearly all other utilities in the region are not experiencing the same level of growth.

Staff also expressed concerns about increasing evidence that economic growth no longer translates into growth in electricity demand the way it has in the past. PGE does not consider this issue in this IRP, and instead maintains that its models include variables representing "fundamental drivers of growth in PGE's service territory." However, the IRP did not consider whether the relationships between the assumed "fundamental" drivers and load has changed over time, despite clear evidence that it has. PGE's long-term forecast takes these "fundamental" relationships as a given and uses the assumptions that the relationship between economic growth and load is linear, constant, and will be the same in the future as it was in the 1980s and 1990s. PGE did not explain these assumptions in its IRP. Staff is concerned that this does not satisfy IRP Guideline 4.b's requirement to explain major assumptions in the load forecast. Staff suggested that PGE consider model specifications to examine this issue by de-trending certain variables further. Contrary to PGE's stance that Staff has not made express recommendations for model specifications, Staff specifically suggested de-trending GDP, energy deliveries, and any other variables exhibiting time trends.[115]

Staff's concerns are not alleviated by PGE's statement that its methods are "consistent with industry standards."[116] It is well known that utilities have incentives for over-building and thus over-forecasting, and the industry in general has a history of over-forecasting electric loads. Staff notes that this is a separate issue from its concerns with PGE's "high" and "low" growth scenarios.

Finally, Staff is concerned that the shortcomings in PGE's load forecast have caused problems in other parts of the IRP. This is because PGE's portfolios are constructed based on assumptions that preclude the possibility that PGE may experience growth that does not accelerate as PGE predicts, but instead remains closer to the growth rates recently experienced by PGE and anticipated by Seattle City Light and PSE.

[115] PGE Final Comments, page 37.
[116] PGE Final Comments, page 35.

General Recommendation 1 – Load Forecast Recommendation

Staff recommends that the Commission direct PGE to:

- Develop probabilistic load forecasts.
- Conduct ongoing workshops with interested stakeholders to continually improve PGE's forecasts.
- Conduct out-of-sample testing and select models based on these results.
- Include a technical appendix in future IRPs that describes forecast methodology and contains a bulleted list of the forecast modeling assumptions (and explanations) and the model specifications (equations).

These suggestions are consistent with the findings in the 2015 study of utility load forecasting commissioned by NARUC.[117]

G #2. Portfolio Ranking & Scoring Metrics

Overview
PGE developed 21 portfolios and ranked ten of them in its IRP portfolio rankings using a weighted system of scoring metrics. The metrics include one cost metric (weighted at 50 percent) and three other scoring metrics intended to reveal the risk associated with each portfolio (each weighted at 16.7 percent). PGE's preferred portfolio is "Efficient Capacity 2021" though the top four portfolios ranked very similarly.

Parties' Position

Sierra Club
Sierra Club stated that PGE's portfolio methodology is "unorthodox" and that PGE's scoring metrics are "deeply flawed."[118] Sierra Club also stated that it is not common practice for a utility to treat a proxy resource as an actionable resource option. Sierra Club recommends that PGE "conduct capacity expansion modeling of its system in order to optimize resource selection rather than rely on pre-determined portfolios."

NIPPC
NIPPC stated that PGE "failed to adequately evaluate how different flexible resource options meet its capacity need" and that therefore the IRP does not provide a "proper foundation for subsequent RFPs."[119] NIPPC also stated that "gas-fired generation, biomass-fired generation,

[117] Hong, T. and Shahidehpour, M. (2015) "Load Forecasting Case Study" Eastern Interconnection States' Planning Council and the National Association of Regulatory Utility Commissioners.
[118] Sierra Club, Final Comments, page 5.
[119] NIPPC Final Comments at 5.

or pumped storage should be considered as preferred options"[120] to meet PGE's generic capacity requirements.

ICNU
ICNU stated that PGE's portfolios do not sufficiently consider the use of market transactions.

NWEC
NWEC stated that the top portfolios are too closely ranked for PGE to select a single preferred portfolio, that PGE's portfolio rankings inappropriately excluded certain portfolios, and that the IRP favors "natural gas resources by underrepresenting other resource options."[121]

RNW
RNW stated that PGE "did not satisfactorily address stakeholder concerns regarding portfolio scoring"[122] and that PGE's "risk scoring metrics lead to an inaccurate selection of the preferred portfolio."[123]

PGE's Position

PGE stated that the portfolios it considered in its rankings represent a "wide range" of options and that its use of proxy resources for evaluating portfolios is "consistent with common industry *practice*."[124] PGE presented a sensitivity analysis of its scoring system in its Reply Comments which does not reveal major changes in the ranking outcomes, leading PGE to state that "the conclusions made in the IRP are robust to the scoring recommendations made by parties."[125] PGE also stated that the "economic value of shorter-than-life" resource options "cannot be evaluated in a generic way within an IRP" because they are "highly sensitive to contract pricing and terms."[126]

Staff Position and Recommendation

PGE's portfolio ranking is ambiguous, likely because PGE's scoring metrics are flawed.

Multiple parties, including Sierra Club, NWEC, and RNW, have expressed concerns with the scoring metrics that PGE used to rank its portfolios. Staff agrees with these parties that the Durability metric in particular is unnecessary, lacks clear quantitative meaning, and unduly influences the portfolio rankings. Staff, along with Sierra Club and NWEC, recommended removing the Durability metric. Likewise, Sierra Club and RNW noted that removal of the Durability metric changes the preferred portfolio. PGE acknowledged that the Durability metric relies on "arbitrary definitions" and is "not comparable on a consistent basis with other cost and

120 NIPPC Final Comments at 4.
121 NWEC Final Comments at 2.
122 RNW Final Comments at 1.
123 RNW Final Comments at 4.
124 PGE Reply Comments at 73 and 86.
125 PGE Reply Comments at 100.
126 PGE Reply Comments at 75.

risk calculations."[127] However, PGE maintains that the Durability metric provides "insight" that is "not captured by other risk metrics."[128] Staff stated that there are alternative ways to capture this information that would be more acceptable than the Durability metric.[129]

Staff shares concerns expressed by NWEC, RNW, and Sierra Club that small changes in assumptions or scoring weights change the rankings of the top four portfolios. Staff and Sierra Club also noted the metrics are vulnerable to distortionary effects. PGE acknowledged that these distortionary effects impact the relative performance of portfolios.[130] However, PGE conducted sensitivity analysis of its portfolio rankings and states that, in contrast to observations made by other parties, the selection of the preferred portfolio is not influenced by the concerns raised by these parties.

Staff and Sierra Club also expressed concerns that PGE's projected load levels do not influence the portfolio rankings, which indicates problems with portfolio construction, the ranking system, the load scenarios, or some combination of the three. Staff also notes that because the high/low load cases have no influence on portfolio selection, these cases are essentially meaningless for the entire IRP process.

General Recommendation G #2. Portfolio Ranking & Scoring Metrics Recommendation

Staff recommends that the Commission not acknowledge PGE's preferred portfolio and not acknowledge PGE's portfolio ranking system. Staff also recommends that the Commission direct PGE to hold workshops with interested parties to develop a simple and clear set of portfolio scoring metrics for use in future IRPs, with a focus on using only metrics that have a clear interpretation and robust discussions on the appropriate way to incorporate short- and medium-term options and the relative importance of high-cost versus low-cost outcomes.

G #3. Distribution System Planning

Overview

Although PGE does not offer an Action Plan item to specifically address Distribution System Planning (DSP), the combination of PGE's projections for demand- and supply-side resources that are located on PGE's distribution system define how PGE is considering distributed energy resources (DERs) in long-term planning for its system. Although the 2016 IRP includes discussion of many DERs, it falls short of providing insight into how PGE views the distribution system as a resource itself and how PGE can plan to use the distribution system as a resource to help meet total system needs, and localized needs, cost effectively in the future.

[127] PGE Reply Comments at 102.
[128] PGE Reply Comments at 102.
[129] Staff Initial Comments at 28-30, and Staff Final Comments at 35.
[130] PGE Reply Comments at 103.

Staff raised two primary concerns during the IRP process:

1. Current utility distribution planning processes may not be transparent enough, nor sufficiently linked to regulatory distribution planning processes and specific dockets[131] to provide comprehensive review and engagement by the Commission and stakeholders; and
2. The current representation of DERs in PGE's IRP may underrepresent the potential contribution of DERs to the utility's system, increasing the risk of showing an inflated resource need in the IRP.

To address these concerns, Staff proposed requesting that a new process for distribution system planning be opened after consultation with stakeholders.

Parties' Position
RNW provided enthusiastic support for Staff's intent to investigate, define, and potentially implement Distribution System Plans. RNW agrees that DSPs could help maximize the value of additional DERs due to their ability to provide greater understanding of location values of these resources and recommends that the Commission consider adopting DSPs in the near future.[132]

PGE's Position
In both their initial and final comments, PGE was supportive of increasing efforts to align its planning process and the regulatory process and suggestions to improve assessment of DERs in future IRPs.[133] PGE is willing to work with Staff on defining a process for distribution system planning and agrees that a Staff request to open an investigation into DSP might be the appropriate first step.[134]

Staff Position and Recommendation
In its final comments, Staff identified several potential benefits to undertaking some form of DSP process to address the above noted areas of concern. The benefits include:

- Creation of a comprehensive, transparent plan for distribution level investments. This plan and the process in developing it would provide a framework for meaningful regulatory review, connecting and streamlining disparate processes and result in superior regulatory guidance regarding utility investment strategies. Creation of this framework would allow the parties to construct preventative measures that address concerns surrounding data, consumer protection, and other complex issues that should be addressed early on in the process to avoid complications in the future.

[131] Includes investigations related to energy storage, Smart Grid Reports, voluntary products, resource value of solar, demand response, and energy efficiency among others.
[132] RNW final comments at 16.
[133] PGE initial comments at 116.
[134] PGE final comments at 43.

- Establishment of clear links between utility distribution system planning and IRP planning would establish the distribution system itself as a resource option to meet bulk system needs.
- Enable intentional locational planning for DERs, by capturing locational value of resources and optimizing use of existing resources, to reduce system costs.

  Minimize the costs and risks of uncoordinated growth and investment. Comprehensive DSP planning could help minimize risks of investing in grid improvements that may not be compatible with other investments, supporting a least-regrets investment strategy.

In sum, opening an investigation to establish a process for DSP that captures these benefits is the next logical step. Although DSP could be an extensive undertaking with multiple facets, Staff has identified specific areas of improvement related to PGE's representation of DERS in its IRP models that can be incorporated in PGE's 2019 IRP. These specific areas include:

- Explicit linkage of external distributed generation penetration forecast study results within IRP assumptions;
- Creation of a range of DER penetration scenarios based on market analysis; and
- Alignment of all major assumptions that are used to drive DER growth with those used in the IRP.

General G #3. Distribution System Planning Recommendation

Staff recommends that the Commission direct PGE to work with Staff and other parties to advance DER forecasting and DER representation in the IRP process to be included in the 2019 IRP. In addition, the Commission should anticipate PGEs participation in working with Staff to define a proposal for opening a distribution system planning process.

G #4. Transmission

Overview
PGE did not consider a specific transmission Action Item in this IRP. All portfolios incorporated transmission costs in their IRP modelling.

<u>Parties' Position</u>

Most of the stakeholder comments on transmission were related to the Montana wind resource.

Sierra Club and NWEC
Sierra Club and NWEC generally felt the transmission costs for portfolios with Montana wind would preclude PGE from choosing portfolios with a need for new transmission.

ICNU
ICNU felt that PGE was justified in delaying RPS action in the near-term to acquire a Montana wind resource at a later date. ICNU also asserted that PGE's transmission capacity at COB and Mid-C should allow it include market transactions in its portfolios.[135]

NIPPC
NIPPC asserted that the IRP failed to put forth a transmission plan in this IRP and did not analyze PGE converting its BPA transmission service to BPA's network service. NIPPC also felt that PGE was reserving significant amounts of transmission, making it difficult for independent power producers to sell power to PGE.

PGE's Position

PGE saw no reason why a Montana wind project could not bid into an RFP for renewable resources and that PGE's estimates of transmission costs for comparison purposes should have no bearing on bid competitiveness.[136] PGE did conduct an additional analysis of potential costs for existing versus new transmission to address parties concerns. PGE notes that acquiring transmission now for Montana wind in the future is highly speculative.[137] PGE also expressed that NIPPC's suggestion to convert its BPA service to Network Integrated Transmission Service (NITS) was impractical on many levels.[138]

Staff's Position and Recommendation

Staff asked for more "high-level" information on the Montana wind option and its associated transmission constraints/options. Staff agreed with several stakeholders that transmission opportunities allowing access to higher capacity wind resources in Montana and Wyoming should be explored. Staff appreciated the suggestion put forth by NWEC and taken up by PGE to convene a working group or hold a workshop on this issue before the next IRP. This approach by PGE satisfies Staff's concerns.

With regarding to PGE converting its current transmission service to NITS, while the concept may have merit in the future, PGE's arguments against NITS in this IRP were strong and compelling; therefore, Staff recommends no further action on this issue at this time.

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135 B. Mullins on behalf of ICNU, Final Comments at 33.
136 PGE Reply Comments at 111.
137 PGE Reply Comments at 113.
138 *Id.*

G #5. Bilateral Contracts

Overview
In PGE's 2013 IRP, the Company sought to renew existing hydro contracts outside of the RFP process, essentially through bilateral negotiations.[139] Staff supported the Company's proposal.[140] By the 2016 IRP however, PGE had not renewed these existing hydro contracts, and further modeled all of the hydro contracts as expiring in the IRP. PGE explained this approach was warranted because renewal was highly speculative and made the assumption that renewal would preclude PGE from getting the best deal possible.[141] Many parties (discussed below), Staff, and the Commissioners encouraged PGE to explore immediate opportunities to acquire regional hydro capacity.[142]

PGE complied with this request and found there was, "...available capacity in the region for sale to meet the capacity need identified in PGE's Action Plan."[143] By the time of filing of its reply comments on March 31, 2017, PGE had begun bilateral contract negotiations with regional generators. The exact amounts and terms and conditions associated with each negotiation are not known. PGE will be evaluating all bilateral resources against each other to promote the selection of a least cost, least risk resource.[144] The timing of when this will be complete is unclear, but it will be after Staff files this Staff Report and likely after the Commission decision on IRP acknowledgement.

Parties' Position

Many parties encouraged PGE to pursue bilateral negotiations to secure capacity resources. All were focused on securing hydro generation ahead of an All Source Capacity RFP. These parties included Staff, CUB, Sierra Club, NWEC, ODOE, and RNW. Sierra Club and CUB both expressed some reservations about significant new capacity being exempted from the competitive RFP process as it further erodes transparency and accountability in the least cost, least risk evaluation process in the IRP. RNW produced a helpful NPVRR analysis and subsequent procurement prioritization that included the bilateral contracts showing that additional hydro could effectively be modelled in a portfolio analysis. [145]

PGE's Position

In the Company's final reply comments they propose to meet customers' capacity needs by acquiring resources through bilateral negotiations first and then if needed through an RFP process. If PGE is able to successfully negotiate term sheets, it will then seek approval from the

139 PGE 2013 IRP at 52.
140 LC 56 Staff Acknowledgment Memo at 6.
141 PGE Reply Comments at 81.
142 Commissioner comments are found in audio of Commission Workshop on 2/16/2017.
143 PGE Reply Comments at 12.
144 PGE Final Reply Comments at 28.
145 RNW Final Comments, 5/12/17.

Commission for waiver of the Competitive Bidding Guidelines so that it can complete the transactions outside of an RFP.[146]

Staff's Position

The bilateral negotiations are a positive development. Staff commends PGE for the work it has done on this matter and for their consideration of stakeholder concerns on this matter. From the information provided, the bilateral resources might have the capability to meet PGE's 2021 resource capacity need.

However, Staff notes that PGE could likely have done this work as part of its research *prior* to filing the 2016 IRP. As was demonstrated by RNW, Staff suspects PGE could have constructed several portfolios with increased hydro and/or resources of various duration with this information in order to present a fuller picture of available least cost, least risk resources for preferred portfolio consideration.

In Staff's recommendation on Supply Side Action Item #2, Staff modified acknowledgement of the capacity acquisition to require the completion of bilateral negotiations and other actions prior to PGE's proposed, All Source RFP being released. Therefore, Staff does not believe any further action need be taken on this issue as it is addressed by SS #2.

G. 6 – PURPA Avoided Costs

Overview
In Order No. 14-058 the Commission adjusted the methodology to calculating avoided costs and the timing of avoided cost filings.

Parties' Position

ICNU
With regards to PGE's Early RPS RFP and acquiring wind in 2017 to be operational in 2020, ICNU felt that requiring customers to pay for a resource they do not need based on speculative long-term benefits will harm customers by requiring them to pay more than necessary for power from QFs.[147]

PGE's Position
PGE requested that the Commission provide PGE with clear guidance on updates to the Company's avoided costs. In their IRP identified a first major action for capacity in 2021. The first major action for RPS compliance is in 2029, unless the Commission acknowledges the Early RPS RFP. Then the first major action for RPS compliance is in 2021 with another major action needed in 2030.[148]

[146] PGE Final Reply Comments at 28.
[147] ICNU Final Comments at 16.
[148] PGE Final Reply Comments at 45.

Staff's Position

Oregon's method of calculating standard avoided cost prices available to eligible Qualifying Facilities under PURPA relies on the IRP as a starting point. The year of the first major resource acquisition in the most recently acknowledged IRP sets the demarcation of "sufficiency" and "deficiency" and therefore the period during which the QF receives compensation based on the avoided resource rather than on market prices. "Major resource" is defined to be the same as in the competitive bidding guidelines: a generation resource of 100 MW or greater and five years or longer. This standard has applied to both renewable and nonrenewable resources.

Staff is recommending that the Commission recognize PGE's 2021 capacity need and acknowledge an action item with conditions that PGE follow a specific order of actions to fill the need. If the Commission were to acknowledge this resource action, the nonrenewable deficiency period would begin in 2021.

Regarding the new major renewable installation, Staff is recommending that the Commission not acknowledge the 2020 new wind resource based on the dominant reasoning that PGE does not have a need for new renewable resources until 2029. If the Commission chooses not to acknowledge this 2020 action, Staff recommends that the renewable deficiency date be 2029 and the proxy renewable resource cost from the IRP be used for the price.

However, in the event that the Commission does acknowledge PGE's early RPS action, it still should not be used to determine the renewable deficiency period. This position is based on the key factor that PGE has no actual need for this resource in 2020. Traditionally, IRPs have been centered on the least cost/least risk portfolio of resources needed to serve load. With the advent of the RPS, an additional compliance need was created. Neither of these "needs" apply to this 2020 resource action. The goal of setting avoided costs for QFs is that ratepayers are "indifferent" to whether the utility purchases output from a QF or meets energy and capacity needs through a portfolio of existing and planned resources that is least cost and least risk. If this resource action receives acknowledgement and is used to set the renewable deficiency date, ratepayers may not be compensating QFs at a rate that is commensurate with least cost and least risk.

Conclusion

Staff appreciates the thorough participation of all parties and commenters to this docket as well as the Company. Staff's specific recommendations as to Guideline compliance, Order No.14-415 compliance, each Action Item, and General Recommendations for PGE's 2016 IRP are found at the beginning of this report and in the boxes throughout the report.

PROPOSED COMMISSION MOTION:

Acknowledge in part and decline to acknowledge in part Portland General Electric's (PGE or Company) 2016 Integrated Resource Plan. Staff recommends certain actions and additional requirements for inclusion in an IRP update.

LC 66 PGE 2016 Integrated Resource Plan

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ATTACHMENT A
IRP Action Plan Overview and Comparison

Area	Nov. 2016 *Original Action Plan*	May 2017 *Final Revisions to Action Plan*
Demand Actions	Energy Efficiency (EE): Acquire 135 MWa	*Same*
	Demand Response (DR): Acquire 77 MW of winter and 69 MW of summer	****Revision**** Enable DR beyond PGE's current targets. Scope and define DR test bed. Launch a DR review committee.
	Conservation Voltage Reduction (CVR): Deploy 1 MWa	*Same*
	CVR: Expand AMI	*Same*
	CVR: Conduct R&D around analytics	*Same*
	CVR: Develop expansion plan	*Same*
Supply Side	New Renewables: 175 MWa through deployment of ~515 MW of new wind	****Revision**** Added 52 MW of renewable capacity from Qualified Facility (QF) contracts, reducing capacity need and pushing out REC need to 2029. This did not impact plan to acquire 175 MWa of new renewable resources (likely wind).
	New Capacity Need: ~850 MW New capacity should be comprised of 375 - 550 MW of dispatchable capacity and ~400 MW of seasonal capacity	****Revision**** New Capacity Need: ~561MW New capacity should be comprised of 240 - 415 MW of dispatchable capacity due to renewed hydro contract and ~ 400 MW of Seasonal Capacity[149]
	DSG: 16 MW	*Same*

[149] See LC 66, PGE IRP Reply Comments, p. 52 and PGE's April 13, 2017, Letter Updating Figure 5, p. 2.

Area	Nov. 2016 *Original Action Plan*	May 2017 *Final Revisions to Action Plan*
	Hydro Contracts: = 0 MW unless contracts renewed	****Revision**** Hydro Contracts: PGE acquired ~135 MW from renewed hydro contract at Wells facility. In addition, PGE is engaged in bilateral negotiations for potentially more hydro capacity. *(See below)*
		****NEW**** Bilateral Negotiations: Beginning in Q1 2017, PGE entered into bilateral negotiations with several hydro capacity resource owners and thermal resource owners of unspecified size and contract duration. A single resource or multiple resources may be selected to help fill PGE's 2021 capacity need. PGE will file waiver from the RFP process in early August for upwards of three resources with capacity products that are competitively priced. PGE will update its 2021 capacity need should any negotiation become a contract; most likely not until December.
Integration	Submit Storage Proposal, per HB 2193, by 1/1/2018	*Same*
Enabling Studies	Market Capacity	*Same*
	Flexible Capacity & Curtailment	*Same*
	Customer Insights	*Same*
		****Revision**** Added several new studies and explorations based on stakeholder comments for the next IRP.

Area	Nov. 2016 *Original Action Plan*	May 2017 *Final Revisions to Action Plan*
Resource Acquisition	One or more than one RFPs for new resources	****Revision**** Will still issue *All Resource RFP* but will notify OPUC of bilateral negotiation status prior to issuing.[150] PGE also committed to updating its 2021 capacity need if it is impacted by any successful negotiations. Will still issue an *Early RPS RFP* to acquire the 175 MWa of wind or some other renewables.
Benchmark Resources	Carty Unit 2 – Not considering; but open to benchmark proposals	*Same*
	Carty Unit 3 – Not considering; but open to benchmark proposals	*Same*
	Renewables – Exploring benchmark opportunities in RFP.	****Revision**** No determination. Not requesting acknowledgement.[151]
	Storage – Exploring benchmark opportunities in RFP.	****Revision**** No longer considering. Developing site for RFP later[152]

[150] *See* LC 66, PGE IRP Reply Comments at 12.
[151] PGE IRP Final Reply Comments at 34. "In any event, the Company has not requested acknowledgement of a benchmark resource."
[152] *Id.*

ATTACHMENT B
Post- Guideline New Major Resource Acknowledgement Table for IRPs

Case/Year Filed/Year Acknowledged	Acknowledged Action Item New Major Resource to be acquired in the 2-4 year action plan period	Need and Year of Need	Timing
LC42/2007/2008 PacifiCorp	2,000 MW of Renewable Resources by 2013, including 400 MW on-line by year-end 2007.	Company projected a capacity deficit system wide beginning 2010. Need met in part by renewable resources: "The PacifiCorp deficits prior to 2011 to 2012 will be met by additional renewables, demand side programs, and market purchases." (P.61 of 2007 IRP)	Resources added starting 2007 for need beginning in 2010: 3 years ahead of start of need. Resources acknowledged in 2008 for need in 2010: 2 years ahead of start of need.
LC43/2007/2008 PGE	323 MWa of Renewable Resources by 2012.	Company projected a capacity need requiring new supply as 2012. Company projected a regulatory need for new renewable energy starting in 2011. (p. 2 and 6 of Order 08-246)	Resources acknowledged in 2008 for need starting in 2011: 3 years ahead of start of need.

Case/Year Filed/Year Acknowledged	Acknowledged Action Item New Major Resource to be acquired in the 2-4 year action plan period	Need and Year of Need	Timing
LC47/2008/2010 PacifiCorp (2009-2018 action plan)	393 MW of wind resources online by year-end 2010. (Of 1,400 MW of renewables by 2018) (p. 3 Order No. 10-066)	Company projected the system becoming energy short in 2012, and capacity short in 2011. (p. 17 Order No. 10-066)	Resources added starting 2010 for need beginning in 2011, 2012: 1 years ahead of need capacity need, 2 years ahead of energy need. Resources acknowledged in 2010 for need in 2011, 2012: 1-2 years ahead of start of need.
LC48/2009-2010/2010 PGE	122 MWa of renewables needed to be in service by 2014 (IRP at 323)	Regulatory need of 15% RPS requirement by 2015.	Resources acknowledged in 2010 for need starting in 2015: 4 years ahead of need. Resources to be operating 1 year ahead of need.

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Case/Year Filed/Year Acknowledged	Acknowledged Action Item New Major Resource to be acquired in the 2-4 year action plan period	Need and Year of Need	Timing
LC50/2009/2010 Idaho Power	300 MW CCCT online 2012 Wind up to 150 MW online 2012	Capacity short in 2013, Energy short in 2014 (p.4 Order No. 10-392)	Resources added starting 2012 for need beginning in 2013: 1 year ahead of need. Resources acknowledged in 2010 for need starting in 2013: 3 years ahead of need.
LC52/2011/2012 PacifiCorp	2012 RFP for peaking/intermediate/baseload resources by the summer 2015	Capacity need in 2011, growing annually after that. (p.3 of Order 12-082)	Resources added starting 2015 for need beginning in 2011: 4 year *after* start of need. Resources acknowledged in 2012 for need starting in 2011: 1 years *after* start of need.
LC53/2011/2012 Idaho Power	None	N/A	N/A

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Case/Year Filed/Year Acknowledged	Acknowledged Action Item New Major Resource to be acquired in the 2-4 year action plan period	Need and Year of Need	Timing
LC56/2013/2014 PGE	No major supply side resources. "In its evaluation, PGE found that its load and resources are balanced through 2019. Accordingly, the company concludes that it requires no new major resource acquisitions in the current 2013-2017 Action Plan time horizon." (p.3 Order No. 14-415)	N/A	N/A
LC57/2013/2014 PacifiCorp	No new major resources. Note: Several SCRs proposed, Nothing acknowledged	N/A	N/A
LC58/2013/2014 Idaho Power	None	Company asserted capacity deficit starting in 2016	N/A
LC62/2015/2016 PacifiCorp	None	N/A	N/A
LC63/2015/2016 Idaho Power	None	N/A	N/A