ORDER NO. 20-152

ENTERED May 6, 2020

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

LC 73

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2019 Integrated Resource Plan.	ORDER

DISPOSITION: 2019 INTEGRATED RESOURCE PLAN ACKNOWLEDGED WITH CONDITIONS AND ADDITIONAL DIRECTIVES

This order memorializes our decision made at the March 16, 2020 Special Public Meeting concerning Portland General Electric Company's 2019 Integrated Resource Plan (IRP). We acknowledge PGE's action plan with conditions and additional directives for PGE's next IRP.

The introduction below outlines our core decisions and overall reasoning. Following that, we provide an overview of IRP requirements and review how PGE addressed them. The final section contains a more detailed discussion and resolution of specific issues.

I. INTRODUCTION

We acknowledge PGE's IRP because it contains a preferred portfolio and a set of resource actions that, with continued examination and refinement of PGE's procurement approach, can reasonably position PGE to capture the best combination of costs and risks for its customers. As always, our acknowledgment means the plan is reasonable at the time of acknowledgment. PGE must continue to ensure its actions remain reasonable considering material changes, including of particular note the unique public health and economic disruptions emerging in Oregon just as we made our acknowledgment decision.

In this IRP, PGE used new modeling approaches and methods to encompass a broader range of risks and uncertainties and navigate toward a preferred portfolio and action plan that balances costs and risks in a time of significant policy and market uncertainty.[1] We appreciate PGE's innovations, and also our Staff's significant efforts to examine how PGE's approach aligned with or deviated from our understanding of the PUC's IRP

[1] We clarify for future readers that PGE's new IRP tools (optimization with screening and set constraints) were implemented in IRP development in 2019, well before the public health emergency that began in Oregon in March 2020.

framework. Throughout the IRP process, Staff and stakeholders encouraged deeper examination of uncertainties that PGE's methods may have missed. This dialogue advanced our understanding considerably. As PGE's modeling evolves, we ask PGE to continue working to build a common understanding of its modeling terms and processes.

PGE selected a preferred portfolio of energy storage and renewable resources to meet its near-term capacity needs and to lower portfolio costs and risks over the long term, including by aligning with state, community and customer goals around decarbonization. We engaged with stakeholders in a detailed discussion of the scope, timing, and mechanics of PGE's planned procurement actions to achieve the goals of the preferred portfolio. We appreciate that PGE adjusted its action plan to place a higher priority on procurement of needed capacity. While we acknowledged PGE's action plan, we conditioned our acknowledgment on further information about how PGE's procurement plan would encourage its renewable energy acquisitions to contribute optimally to meeting PGE's capacity need without undermining its portfolio cost- and risk-mitigating energy value.

Increasingly, utilities have approached the IRP process as iterative. Where once IRPs were used to compare generic resource technology types and action plans were often designed to capture the best actual bids from resource technologies specified in the preferred portfolio, recently utilities have proposed to run open procurement processes that use IRP-like modeling to evaluate resource bids from a wide variety of technologies to produce a best cost/risk outcome that achieves the goals of the preferred portfolio. This evolution addresses both the rapid changes facing the energy sector and maximizes the value of competitive procurement for customers, but it introduces much of the complexity of the IRP into RFP analysis. As we approach the RFP, we will continue to depend on PGE to rigorously update its needs assessment and assessment of changing conditions; to ensure that the way PGE and others manage transmission rights does not unreasonably diminish the significance of portfolio analysis in resource selection and to better justify how separate or combined procurements will result in an optimized portfolio. This work will continue in a docket for selection of an Independent Evaluator (IE) and approval of one or more RFPs.

II. IRP REQUIREMENTS AND PGE'S 2019 IRP

A. Overall Purpose

The IRP is a road map for providing reliable and least cost, least risk electric service to the utility's customers, consistent with state and federal energy policies, while addressing and planning for uncertainties.[2] 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."[3] 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.[4]

B. IRP Guidelines

Our IRP guidelines cover thirteen aspects of IRP process and content. A full discussion of how PGE addresses the IRP Guidelines in its 2019 IRP is provided in Appendix A of the IRP. We briefly address the first two guidelines, which set forth the key substantive and procedural requirements for IRPs.

1. Guideline 1 – Substantive Requirements

Guideline 1 describes the primary substantive requirements of an IRP. The first subpart covers resource options, and provides that all resources are to be evaluated on a comparable basis. PGE explains that it considered all known supply-side and demand-side resources. The following supply-side resources were tested with a transmission wheeling cost added: central-station solar, solar-plus-storage, wind, geothermal, biomass, pumped hydro, battery storage, and natural gas facilities. The following demand-side resources were tested: energy efficiency (EE), demand response (DR), and dispatchable standby generation (DSG).

The second subpart of Guideline 1 provides that an IRP must consider risk and uncertainty. PGE explains it analyzed 270 need, price, and technology futures. PGE's need futures considered the uncertainties associated with load forecast, energy efficiency forecast, distributed resources and market availability. PGE's price futures considered wholesale market conditions with a range of gas prices, carbon prices, and electricity prices. PGE's technology futures considered a range of costs for wind, solar and battery storage.

The third part of Guideline 1 states that the primary goal of an IRP is the "selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers." This guideline states that net present

---

[2] *In the Matter of Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 at Appendix A, Guidelines 1-13 (Jan 8, 2007) corrected by Order No. 07-047 (Feb 9 2007); *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).
[3] Docket No. UM 1056, Order No. 07-002 at Appendix A, Guideline 1.
[4] *Id.* at Guidelines 1 and 4.

value of revenue requirement (NPVRR) is the main cost metric, and that utilities must balance cost and risk over at least a 20-year planning period. PGE's 2019 IRP uses a 30-year planning horizon. PGE minimized NPVRR in its "scoring optimization run," the second stage of its portfolio modeling, which is discussed in more detail below.[5]

The final part of Guideline 1 requires the IRP to be consistent with the long-run public interest as expressed in Oregon and federal energy policies. PGE's IRP discusses the planning environment and states that its IRP reflects known policies including the Oregon Clean Electricity and Coal Transition Plan (SB 1547).[6] PGE developed its IRP carbon price forecasts with reference to policies under discussion in the Oregon legislature, portions of which are now reflected in the greenhouse gas emission reduction goals in Executive Order 20-04, signed by Governor Brown on March 10, 2020. PGE also explains that its 2017 customer survey suggests that some stakeholders and many customers express a strong preference for seeing PGE transition its generation from fossil fuel to clean and renewable resources, and that PGE has adopted a corporate goal to reduce its carbon emissions 80 percent from 1990 levels by 2050.

2. Guideline 2 – Procedural Requirements

Guideline 2 describes procedural requirements, stating that the public should have substantial involvement in IRP development.[7] PGE states it hosted public input roundtables throughout 2018 and 2019, and a wide variety of stakeholders commended PGE for the quality of its public engagement in IRP development.

Our proceeding to review PGE's filed IRP involved an 8-month process in which Staff, stakeholders, and PGE filed three sets of detailed comments and we held three Commission Workshops to discuss issues with each other and all the parties. Staff released a memo for the March 16, 2020 meeting that summarizes stakeholders' comments more fully than this order, and also lists Staff's recommendations. Eight stakeholders or parties filed comments on Staff's memo, including: the Alliance of Western Energy Consumers (AWEC), Multnomah County, the Northwest Energy Coalition (NWEC), the Citizens' Utility Board of Oregon (CUB), Swan Lake, the Renewable Energy Coalition (REC), and the Northwest and Intermountain Power Producers Coalition (NIPPC).

---

[5] PGE 2019 IRP at 176 (Jul 19, 2020)
[6] ORS 757.518 (2019).
[7] Guideline 2 also requires regulated energy utilities to prepare and file IRPs within two years of acknowledgment of the utility's last plan. See also OAR 860-027-0400(3). We acted on PGE's last IRP on August 8, 2017, and PGE filed its 2019 IRP less than two years later, on July 19, 2019.

C. Action Plan

According to our IRP Guidelines, the action plan should detail the resource activities the utility intends to undertake over the next two to four years to acquire the resources reflected in the preferred portfolio of supply-side and demand-side resources.[8]

PGE states that its action plan is not designed to identify a specific set of resources but to specify a set of reasonable actions that would allow PGE to capture the cost and risk benefits of the top performing portfolios, shown in its preferred portfolio. PGE's 2019 action plan describes three sets of actions: customer actions, a renewable action, and capacity actions. The customer actions include acquisition of all cost-effective energy efficiency and customer participation in demand response and dispatchable customer resource programs. The renewable action, as filed, includes a request for proposals for up to approximately 150 MWa[9] of renewable resources in 2023 to capture federal tax credits. The capacity actions, as filed, were staged. First, PGE would pursue cost-competitive, bilateral agreements for existing capacity in the region. Next, PGE would meet remaining capacity needs through a request for proposals from non-emitting capacity resources, in order to match the key attributes of the storage resources (6-hour batteries and pumped storage) that comprised the new capacity in PGE's preferred portfolio.[10]

D. Acknowledgement

Our acknowledgement of an IRP means that the Commission finds that the utility's plan is reasonable at the time of acknowledgment.[11] In the past we have declined to acknowledge specific action items if we are not satisfied that the proposed action is part of a portfolio representing the best combination of cost and risk for customers.

Acknowledgment is not a guarantee of cost recovery, nor is consistency with an acknowledged plan a requirement for recovery of resource costs in rates. Acknowledgment provides guidance for later ratemaking proceedings, which are the forum for the Commission to make its ultimate decision to approve or disapprove a resource procurement as prudent and recoverable in customer rates. Consistency with an acknowledged plan may be used as evidence in support of favorable ratemaking treatment, but the utility still must demonstrate that its actions remained reasonable,

---

[8] Docket No. UM 1056, Order No. 07-002 at Appendix A, Guideline 4.
[9] PGE use an average MW (or MWa) in its filings to describe the size of renewable resources. PGE explains MWa is shorthand for the amount of energy that a resource produces on average over the course of a typical year. Because renewables and many power plants do not produce energy all of the time, they typically produce fewer MWa than their total generating capacity.
[10] PGE 2019 IRP, § 8.1, Key Elements of the Preferred Portfolio.
[11] Order No. 07-002 at 16 (Jan 8, 2007).

particularly in light of any material changes in the facts, circumstances and assumptions that supported IRP acknowledgment.

E. Application of Competitive Bidding Rules

Through docket AR 600 and Order No. 18-324, we expanded the competitive bidding guidelines from Order No. 14-149 and issued new competitive bidding rules. PGE's 2019 IRP is the first IRP filed since the rules were finalized. The rules are designed to recognize the increasing overlap between IRP and RFP processes and to better integrate the RFP process with the IRP, in part by accelerating discussion of RFP design and its relationship to IRP analysis. The new rules require initial RFP design and scoring methodology to be filed either in the IRP, or later in the independent evaluator proceeding.[12] PGE sought to satisfy this requirement with IRP Appendix J containing RFP design and modeling methodology.

III. DISCUSSION

A. PGE's Portfolio Analysis

In this section we discuss the building blocks of PGE's IRP—its resource need and resource options. We then describe PGE's portfolio construction and its scoring process with traditional and non-traditional scoring metrics, including a new portfolio optimization tool. PGE's portfolio analysis is important because it leads to PGE's selection of a preferred portfolio and the set of actions to capture that portfolio's attributes that comprise PGE's action plan.

After considering comments on various aspects of PGE's portfolio analysis and preferred portfolio selection, we direct certain changes for PGE's next IRP, and we acknowledge the IRP's preferred portfolio because it reasonably captures the best combination of costs and risks for PGE's customers.

1. Load Forecast

PGE's load forecast begins with its traditional forecast of consumption based on weather and the economy. Energy Trust of Oregon's (Energy Trust's) energy efficiency savings projections are embedded in PGE's top-down load forecast, and incremental energy efficiency savings are included in the low need future. In compliance with our directive from the 2016 IRP,[13] PGE engaged a consultant to perform a Distributed Energy and Flexible Load Study (DER Study) for the 2019 IRP. The DER Study forecasts customer

---

[12] OAR 860-089-0250

[13] *In the Matter of Portland General Electric Company, 2016 Integrated Resource Plan*, Docket No. LC 66, Order No. 17-386 at 19 (Oct 9, 2017) ("Work with Staff and other parties to advance distributed energy resource forecasting and distributed energy resource representation in the IRP process.").

adoption for all distribution-connected resources at an aggregate system level through the planning horizon. PGE states that adoption trends for electric vehicles and distributed photovoltaics are not well captured by the initial-top down forecast, and that including this uncertainty in the forecast is a major enhancement to its load forecast in the 2019 IRP.

PGE does not exclude load associated with its voluntary green energy programs. PGE states that, because these programs have not yet started or are relatively new, the 2019 IRP considers potential customer participation in these programs in sensitivities. PGE states the sensitivities have little impact on PGE's needs.[14] PGE states it will monitor participation in future IRPs and IRP Updates.

PGE states that it has excluded long term direct access customer loads and new load direct access customer loads from all of its needs assessments, including energy, capacity, RPS, and flexibility needs. PGE explains that in docket UE 358 it has requested that we allow PGE to plan for the capacity needs associated with these loads. In this proceeding, PGE requests that we modify IRP Guideline 9 to allow it plan for long-term direct access load.

a. Comments

Staff and AWEC state that PGE's load served by its voluntary renewable programs such as its new green tariff should be excluded from the load forecast. Staff and AWEC state that 100 percent of the green tariff customers' energy requirements will already be covered by the renewable subscription resource, so PGE's inclusion of this load will lead to PGE over-procure new resources.

Regarding treatment of direct access, AWEC proposes that long-term direct access load be treated as a resource option to reduce supply-side procurement. AWEC states that PGE has failed to recognize that some cost-of-service load will transition to direct access. AWEC states that, at a minimum, this issue should be considered in UM 2024.

CUB shares the above concerns and is also concerned that PGE's industrial load forecast may be inaccurate because PGE is not using a localized index that reflects the Northwest's high tech industries and retail rates. CUB and NWEC also question whether PGE's forecast incorporates the significant opportunity for energy efficiency at data centers, which are a key component of PGE's industrial load growth projections.

Regarding PGE's request to modify IRP Guideline 9, NIPPC opposes any change in this proceeding. NIPPC states that PGE has not supported its claim that there are resource

[14] PGE 2019 IRP, § 4.7.2 Voluntary Renewable Program Sensitivities.

adequacy problems associated with direct access. NIPPC believes that resource adequacy is a serious issue to be fully considered in docket UM 2024.

b. Resolution

We discussed Staff and parties' concerns over PGE's base case assumption of zero participation in PGE's voluntary green energy programs.[15] While PGE's sensitivities showed only a modest decrease to its energy and capacity needs from its green energy programs, we find there is some risk of PGE over-procuring resources if it fails to consider these programs. PGE has committed to update its needs assessment in a RFP docket with a consideration of the capacity and energy impacts of its green tariff. We also direct PGE to incorporate examination of customer program growth assumptions, including utility-offered programs and direct access, in its next IRP. We address energy efficiency considerations below.

We do not modify IRP Guideline 9. We will further consider direct access load in IRPs in docket UM 2024.

2. Existing Resources and Resource Transitions

PGE explains its Boardman Power Plant in northeastern Oregon provides 518 MW of net capacity. PGE will cease coal operations at this plant at the end of 2020. PGE states that, since it committed to cease coal operations in Oregon, it has worked with Energy Trust to maximize the energy efficiency available in its territory. PGE states that since its last IRP, it also has secured long-term contracts with regional entities for more than 300 MW of capacity, additional contacts for qualifying facilities (QF), and completed the 2018 Renewables RFP, resulting in the addition of the Wheatridge renewable energy facility expected to enter service between 2020 and 2021. The Wheatridge facility consists of 300 MW of wind, 50 MW of solar, and 30 MW of battery storage.

SB 1547 requires PGE to exit its remaining coal facility, Colstrip 3 and 4, no later than the end of 2034. PGE completed two sensitivities evaluating Colstrip exit at the end of 2027. PGE found cost savings and greenhouse gas reductions in these sensitivities, and also an increased capacity need at a time of an already large capacity need. PGE stated it would continue to examine options related to Colstrip units 3 and 4 as additional information becomes available and will continue to prioritize cost impacts and risks to customers, reliability, and GHG emissions implications.

[15] *In the Matter of Portland General Electric Co., Investigation into Proposed Green Tariff*, Docket No. UM 1953, Order No. 19-075 (Mar. 5, 2019).

a. Comments

Staff requests enabling analysis on customer rate impacts of early Colstrip exit, including modified depreciation schedules. Staff also requests quarterly updates on Colstrip activities. Multnomah County supports Staff's recommendations. Multnomah County explains that Colstrip's co-owner utilities are taking actions to prepare for early exit and the plant's economics are deteriorating. Multnomah County requests that PGE engage in comprehensive analysis evaluating the implications of removing Colstrip from its portfolio by various dates, including by 2025.

b. Resolution

We agree this is a critical moment for analysis of PGE's involvement in Colstrip 3 and 4. PGE communicated a sense of urgency to complete a Colstrip study and committed to complete the analysis by July 31, 2020. We consider this time frame reasonable, and because we expect that discussion of PGE's study will provide a framework for next steps, we do not establish a required schedule for updates at this time.

3. Evaluation of Capacity and Energy Needs

In this IRP, PGE added low and high capacity need assessments in addition to the traditional reference case. PGE states its reference case capacity shortage is 190 MW in 2021, increasing to 685 MW in 2025. PGE explains its capacity needs have increasing uncertainty over time. A major uncertainty in the near term is that half of its capacity need in 2025 is due to contract expirations, and some of those contracts may be successfully renegotiated. PGE also explains its largest long-term uncertainties are the top down weather and economic forecast, as well as electric vehicle adoption.

For energy needs, PGE explains that it traditionally compared the annual energy available from existing and contracted resources with forecast loads in its Energy Load Resource Balance (LRB).[16] The traditional energy LRB models renewable and hydro energy based on average conditions, thermal resources based on their capacity ratings (minus outages), and peaking resources to provide no energy. PGE's energy LRB shows it is surplus 26 MWa in 2021 transitioning to a 109 MWa deficit in 2025. The energy LRB is based on annual average available energy from resources, without regard to projected economic dispatch. PGE believes that, in the future, its low heat rate thermal generators may not be operating as baseload generation throughout the year due to economic dispatch, and the energy LRB may be a less relevant indicator in a market with increasing levels of renewables and carbon pricing.

[16] PGE 2019 IRP, Appendix G.

PGE proposes an alternative approach to evaluate portfolio selection from an energy perspective, referred to as the market energy position. PGE states the market energy position identifies the portion of its customers' energy needs that are expected to be met with PGE's portfolio of resources versus purchases from the market. It identifies the amount of load PGE would serve from market purchases rather than dispatching available, but higher-cost, portfolio resources. PGE clarifies that a short market energy position would not mean that PGE relies on the market for resource adequacy, rather that the energy available from the market is anticipated to be lower cost than energy from a portion of PGE's resource portfolio during some parts of the year, making PGE a net purchaser from the market.[17]

The purpose of the market energy position analysis, PGE states, is to develop a balanced energy portfolio in which PGE is neither persistently a net seller in the market nor persistently a net purchaser in the market. PGE's IRP model selected near-term acquisition of large amounts of low-cost renewable resources that reduced expected portfolio cost in many projected futures, but resulted in portfolios that were both significantly oversupplied from a traditional energy LRB perspective and resulted in a long market energy position (i.e., made PGE a net seller to market on an annual basis). Evaluating portfolios using the market energy position, PGE states, allows PGE to avoid portfolios that are persistently long to the market while avoiding economic risks related to being overly reliant on market purchases.

PGE explains its market energy position compares forecast loads to forecast generation across 54 futures that encompass uncertainties in both PGE needs and market conditions (including carbon prices assumed to begin in 2021). PGE estimates its market energy position, without resource additions, to result in 527 MWa in net annual market purchases in the reference case in 2025. PGE found its market energy position is likely to exceed 250 MWa in net annual market purchases across a wide range of futures in both the near and long term.

For qualifying facilities, PGE forecasts that no new QF contracts will be added during the planning horizon in its reference case. PGE includes a sensitivity analysis for high and low forecasts of QF generation. PGE's high forecast includes contracts that are already in progress toward execution.

[17] 2019 IRP, §4.4.1, Market Energy Position.

a. Comments

Swan Lake supports PGE's overall approach of presenting a range of potential capacity needs, with low and high need futures providing a range of uncertainty around the reference case. Swan Lake argues that PGE's reference case may be overly conservative.

AWEC believes that PGE's capacity deficit is overstated because PGE will acquire resources for its Green Tariff (discussed above), and because PGE does not model its transmission rights that allow for market imports. AWEC also believes that PGE is likely to meet a substantial portion of its capacity deficit through bilateral contracts.

Staff explains that PGE shows a wide range of uncertainty in its capacity need, in large part due to the uncertainty over whether existing capacity contracts will renew or expire. Staff states that in the high need future, PGE has a large capacity need, and that PGE should not prioritize near-term energy procurement that is not needed over a real need for capacity within the action plan timeframe.

PGE agrees there is a wide range of uncertainty in its capacity need and explains that load is the largest driver of uncertainty. PGE explains it designed its capacity action (discussed below) with stages to provide flexibility to respond to updated load forecast information.

On energy, AWEC and Staff caution against using the market energy position to quantify an energy resource "need" or deficit. Staff further notes that PGE should avoid using language that implies that the market energy position reflects a resource need, and should continue to provide the energy LRB as a reference in future IRPs. AWEC states this approach of forecasting energy resource need based on economic dispatch is inconsistent with how other utilities plan.

Staff requests that PGE expand its modeling approach for QFs. Staff states that without QFs, PGE's resource need may appear greater than what is needed. Staff recommends that PGE include a forecasted level of QF generation based on past QF generation levels and reasonable expectations for the future.

REC recommends two changes to PGE's QF modeling. REC recommends that we assume that between 25 percent and 50 percent of new QFs with contracts to sell power to PGE will become commercially operational. REC also recommends we assume a 100 percent renewal rate for existing QFs, explaining that most QFs continue selling power to their host utility.

b. Resolution

i. Capacity

A few parties raised concerns that PGE's capacity need was too broad and imprecise, and PGE largely resolved the concerns by filing an updated needs assessment and by providing sensitivities on full subscription to the green tariff and different levels of QFs coming online and renewing. Staff summarized that even with the sensitivities, PGE maintains a 300 to 700 MW capacity deficit in 2025.

We appreciate Staff and stakeholders pointing out the major uncertainties inherent in PGE's IRP futures. In this proceeding we saw how PGE was able to bring its capacity need into greater focus through its updated needs assessment and expanded and updated sensitivity analysis. By the end of this proceeding, all parties largely agreed with PGE's capacity need.

We will depend on PGE providing clear and thorough needs assessment updates in its IRP Update and prior to any RFP (likely in its IE selection docket). PGE shall make best efforts to refresh the same inputs that it updated in November 2019 in this proceeding, with the latest available econometric load forecast, resource updates for the green tariff subscription level, updated QF levels and sensitivities, and updated market capacity information.[18] For PGE's market capacity update, PGE is to consult with Staff about what data (in addition to coal retirements) can be updated in PGE's exiting market capacity study tool.

ii. Energy

We credit Staff for closely examining PGE's novel market energy position analysis and for maintaining a sharp focus on what the analysis does, and does not, demonstrate. Staff is correct that PGE's market energy position analysis does not demonstrate an energy "need" or "shortage." We agree with Staff that PGE's terminology was confusing and problematic, insofar as it implied that a short position to market was equivalent to a "need" for energy. PGE should continue to work with stakeholders to refine the vocabulary around this issue so we can more clearly communicate about resource needs and resource economics.

However, absence of an energy need from a traditional energy LRB perspective should not prevent consideration of resources whose energy value lowers long-term portfolio costs and risks. Our IRP guidelines state that the primary goal of the IRP is "selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties." In market conditions dominated by ample energy supply and

[18] *See infra* p. 13 (QFs).

continuing growth in energy-rich renewable resources, the pertinent questions are not limited to whether PGE can meet its customers' energy needs, but also include how PGE can best manage the present and future costs and risks of doing so.

We understand that PGE intended to use the market energy position as a tool not to define an energy "need" but to inform a balanced portfolio position that captures portfolio cost reductions from adding low-cost, tax-credit-eligible renewable resources, but avoids risks associated with a portfolio that is persistently a net seller to the market. It offers insight into when an energy position could be considered "too long" because PGE would be adding resources to displace existing resources that would otherwise have been expected to beat market and dispatch to load. But it does not demonstrate whether adding new resources offers a better cost and risk profile than alternatives (market purchases or dispatching existing resources). Although the market energy position analysis does not, on its own, demonstrate that any level of new energy addition is part of a best cost/risk portfolio, we regard PGE's market energy position analysis as one reasonable tool to help evaluate the appropriate energy position of a best cost and risk portfolio in a future dominated by zero variable cost, zero emission renewable resources and uncertainty about future market, technology, and carbon prices.

Though we found the market energy position to be a useful tool that informs our view that 250 MWa is an appropriate modeling constraint on PGE's near-term energy additions, it does not provide a conclusive answer to what is the "right" energy position for PGE's portfolio. It does not eliminate the need for continued development of analyses of the type that PGE, with prompting from Staff, undertook to test portfolio performance against future conditions that may be significantly different from base case expectations. PGE also should continue to provide an energy LRB in future IRPs, so that Staff and parties may continue to use that traditional depiction as a reference point for evaluating portfolio selection.

iii. QFs

Although we discussed the reasonableness of PGE making some assumptions about success rates for uncertain QF contracting outcomes, just as it does for other future uncertainties, most of the QF modeling issues raised by stakeholders here will be addressed more broadly in docket UM 2038. In the meantime, PGE's needs assessment update in the context of the RFP will provide an important refreshed snapshot of recent QF activity, and PGE has also committed to provide updated QF sensitivities. This update will provide an important opportunity to avoid utility over-procurement without inadvertently skewing our current approach to setting avoided costs.

4. Renewable Portfolio Standard (RPS) Need

PGE generally models its portfolios to achieve "physical" RPS compliance, which for PGE means that the volume of Renewable Energy Credits (RECs) generated by PGE's portfolio in a given year will meet or exceed the RPS obligation in that year, without consideration of the availability of banked or unbundled RECs for compliance. PGE's physical RPS position shows RPS obligations will exceed generation from RPS-eligible resources in 2030, when RPS requirements increase from 27 percent to 35 percent of retail load. When PGE instead models use of its REC bank to meet compliance obligations (which, in fact, is PGE's practice), PGE states its existing resource portfolio is sufficient to meet RPS obligations through 2035. PGE states that depleting its REC bank in that manner would require PGE to procure an additional 627 MWa of RPS-eligible resources by 2037 would delay the benefits of bringing new renewable resources onto the system, and is contrary to the intent of SB 1547, customer preferences, and the company's long-term decarbonization goals. PGE clarifies that its IRP model does not select renewable resources in the near term to meet RPS needs; the presence of renewable resource procurement in the preferred portfolio during the action plan window is driven by economic analysis.

a. Comments

Parties agree with PGE that near-term selection of renewable resources is not driven by PGE's physical RPS compliance modeling. Staff and AWEC nonetheless recommend that the Commission specifically decline to acknowledge PGE's physical RPS compliance modeling approach, because it could influence the action plan in future IRPs. Staff and AWEC state that PGE's strategy results in a large REC bank, without any demonstration that these RECs will be used for customer benefit. Staff and AWEC also recommend that PGE forecast the acquisition of 20 percent unbundled RECs in future RPS need forecasts and related modeling, to match PGE's actual practice of acquiring unbundled RECs for compliance purposes.

Staff and AWEC also state that PGE's voluntary green energy programs (green tariff and community solar) may impact PGE's REC position by reducing the retail sales that affect the determination of RPS requirements. Community solar does not produce RECs for RPS compliance, but reduces the RPS obligation through a reduction in retail sales; similarly, RECs produced from green tariff program resources flow to participating customers, not to PGE's portfolio.

b. Resolution

PGE's near term action plan is durable regardless of RPS modeling, but removing the physical compliance assumption does impact resources in the portfolio over the long term. We recognize Staff and stakeholders' growing frustration with PGE's insistence on physical compliance modeling, and consider it important for PGE to proactively, consistently, and clearly show how portfolio results would change if PGE used an RPS compliance assumption that more closely matches its actual compliance strategy. This would involve maximizing use of unbundled RECs, which PGE has consistently done for RPS compliance, and should also involve using portfolio optimization tools to inform the least cost, least risk RPS compliance strategy.

We do not require PGE to base its ultimate portfolio selection on a particular RPS compliance strategy, but we do not expect Staff and stakeholders to have to ask PGE to perform modeling of the lowest cost RPS compliance strategy. We expect PGE to show in the IRP Update and the next IRP whether physical RPS compliance is driving portfolios, and if so, how. If there is a difference due to physical compliance, then PGE may still be able justify a portfolio consistent with physical RPS compliance based on evaluation of other risks and benefits, such as avoiding concentrated spikes in procurement requirements, expected greenhouse gas reduction and clean energy policies, and economic modeling, but that should be demonstrated in the future.

We note that PGE's renewable resource action, discussed below, appears to assume that PGE will seek the RECs from renewable resources justified based solely on economic modeling, thereby adding to its very large REC bank. Future evaluation of renewable resource additions should examine whether PGE's RPS compliance strategy requires it to secure project RECs in the near-term and explain the cost-benefit tradeoff for PGE customers.

5. Climate and Greenhouse Gas Emissions

Climate and greenhouse gas emissions are considered in PGE's IRP in several places. PGE states that it aims to decarbonize its energy system as cost effectively as possible. PGE estimates that it will need to add at least 50 to 60 MWa of new renewables every year for the next thirty years to meet its decarbonization goals.

As a supply side resource, PGE did analyze four natural gas fueled resource options, including combined-cycle combustion turbines and simple-cycle combustion turbines. PGE determined that portfolios with thermal resources tended to have lower expected costs but higher risks. PGE states that adoption of clean energy policies in the West and continued technological progress favors non-emitting capacity resources. Thus, PGE's action plan does not pursue the development of new thermal resources to meet PGE's identified capacity needs in 2025.

In its policy risk analysis, PGE considers potential carbon prices by including a low, medium, and high carbon price in its IRP analysis, with the reference case modeled on legislative discussions in the state of Oregon. PGE also applies a greenhouse gas screen to eliminate further consideration of certain portfolios with the highest levels of greenhouse gas emissions.

a. Comments

Staff and Multnomah County request a more holistic approach to decarbonization that includes consideration of resource retirement, demand-side resources, and distributed and community energy as well as new supply side resources. Staff and Multnomah County both assert that PGE should pair early exit of Colstrip with new generation resources. Staff also proposes that PGE build on its 2016 climate change study to develop an updated climate adaptation and system impact plan. Staff states the climate adaptation plan should describe the specific actions PGE will take to adapt and respond to the risks presented by climate change including wildfire risk, population growth, severe weather, hydro flows and stream temperature changes, air temperature increases and changes in duration, and air conditioning penetration.

b. Resolution

PGE reasonably approached risk analysis in the area of greenhouse gas emissions in this IRP, particularly in its supply side actions and with its separate decarbonization study, but we agree with Staff and Multnomah County's request for PGE to consider decarbonization more thoroughly across its portfolio actions, given the risks PGE identifies around climate change and given the policy direction within which PGE operates its business. We direct PGE in its next IRP to consider a wider set of decarbonization pathways within a best cost/risk framework.

We appreciate that PGE agreed to provide a climate adaptation strategy as an enabling analysis for the next IRP. This will be a helpful document to orient discussions around low water conditions, new flow patterns, and higher temperatures resulting from climate change. These changes will have differing impacts on both the performance and availability of generating resources and on the shape and peak of load over the twenty-year IRP planning horizon.

To advance a common understanding of whole portfolio decarbonization, we plan to hold a Commission workshop during the 2021 IRP development process to assess PGE's progress in developing and representing in its IRP a holistic decarbonization strategy, in the context of how other GHG policy drivers have developed. It is important that PGE consider its entire portfolio—including existing resource dispatch and transitions, new resource additions, and customer and demand-side resources—to deliver a full picture of how a least-cost, least-risk portfolio may also meet customer, company, community, and state decarbonization goals. We encourage PGE to consider portfolios that achieve PGE's proportionate share of the greenhouse gas emission reductions in Executive Order

No. 20-04, as well as developing least-cost, least-risk strategies for assisting communities in its service territory that seek deeper, faster reductions.

6. Supply Side Resource Options and Transmission

PGE's IRP incorporates updated proxy costs and energy generation for utility-scale resources in three different categories: renewables, storage, and natural gas. For renewables, PGE analyzed wind projects in four locations, Oregon single-axis tracking solar photovoltaic (PV), solar plus storage, Northwest geothermal, and a steam generator fueled by woody biomass. For storage, PGE included two utility energy storage technologies, lithium-ion batteries and pumped hydro storage. For natural gas, PGE analyzed four technologies.

PGE explains that its service territory is a compact area in the Willamette Valley. PGE owns and operates its own transmission system, mostly within its service area. PGE is highly reliant on Bonneville Power Administration (BPA) transmission to deliver remote resources. PGE's IRP analysis assumes one wheel of BPA transmission cost for most supply options, including Washington wind (the highest ranked proxy resource).

a. Comments

Staff commented that IRP analysis could be more instructive if it evaluated the trade-offs between selecting resources from areas with the best renewable generation profile and areas with greater transmission availability. NWEC recommends the 2021 IRP include an initiative to co-optimize power and transmission for Oregon solar and Montana wind. PGE explained the difficulties with transmission modeling, as transmission availability is constantly changing and upgrade costs are not known until a specific project is studied. Nonetheless, PGE agreed to investigate how it can incorporate transmission availability of sub-regions to inform resource choices.

b. Resolution

In its IRP, PGE identifies transmission uncertainties in a narrative discussion in its IRP, but PGE does not incorporate transmission uncertainties into its resource analysis. We ask PGE to expand its transmission modeling so that it includes known transmission availability, constraints, options, and costs. While we agree with PGE that the transmission costs can be determined in a RFP process, we also agree with Staff that transmission cost and availability have a major impact on resource choices and that if this information is known or can be meaningfully projected to inform resource selection, it should be incorporated into IRP analysis.

7. *Portfolio Construction and Preferred Portfolio Selection*

With its capacity need and market energy position analysis, PGE developed 43 portfolios across a wide range of resource options and future conditions. PGE engaged in a two-stage portfolio construction process for each individual portfolio. The first stage is portfolio optimization, where PGE solves for resource additions across all years and all futures based on set objectives and constraints. The second stage is scoring optimization, where PGE held the best performing portfolio of near-term acquisitions in the reference case constant across futures and solved for the set of resource additions after 2026 in each future that minimized the net present value revenue requirement (NPVRR), calculated between 2021 and 2050 in that future.

To score its portfolios, PGE took four steps. First, PGE used non-traditional screens to remove portfolios from further evaluation, including those that added more than 250 MWa of near-term energy. Next, PGE evaluated portfolio performance on the traditional basis of total cost and risk. Seven portfolios emerged as the top performing portfolios.

PGE identified the common aspects of the seven top portfolios to develop a single preferred portfolio. These common aspects included all cost-effective energy efficiency, up to 150 MWa of federal tax credit eligible renewable resources in 2023 or 2024, and non-emitting capacity in an amount aligned with PGE's updated needs assessment by 2025. PGE used these common elements to construct the Mixed Full Clean portfolio and identified it as the preferred portfolio for the 2019 IRP.[19]

In response to our first order in PGE's 2016 IRP, which concluded that PGE had not "demonstrate[d] that the long-term cost savings it identified from near-term action were adequately balanced with the short-term rate impacts,"[20] PGE incorporated intergenerational equity analysis in this IRP. Intergenerational equity analysis addresses whether today's customers should be paying for resources that will benefit customers in future years. PGE estimated the price impacts of pursuing 150 MWa of renewables in the near term against the same addition in 2026 without PTCs. PGE determined that PTC eligible wind has a lower near-term rate impact, compared to the same addition in 2026.[21]

a. *Comments*

Staff has concerns about PGE's use of non-traditional metrics to screen out portfolios, in particular when the screens remove portfolios prior to considerations of traditional cost and risk. Staff believes the screens skew the portfolio selection because they remove portfolios based on one future or one criterion. Staff states that PGE should work with

[19] PGE 2019 IRP §7.2, Portfolio Performance.
[20] Order No. 17-386, pages 2-3; see also page 15.
[21] 2019 IRP § 7.3.1. Preferred Portfolio Performance.

stakeholders to refine the non-traditional metrics so that they can be used to help compare the trade-offs between portfolios. Staff also questions whether PGE's final preferred portfolio and action plan bear sufficient relationship to the modeling results.

b. Resolution

We recognize that Staff had to devote significant additional scrutiny to PGE's IRP to determine whether two major changes PGE made in its methodology for arriving at a preferred portfolio—using non-traditional screens and crafting the preferred portfolio from common elements of several top performing portfolios—were valid and produced a least cost, least risk outcome. We appreciate both PGE's innovation and Staff's additional scrutiny.

Through review and testing, PGE demonstrated what its portfolios would have looked like if the screens were not applied, compared its constructed portfolio to optimized portfolios, and ultimately justified the results that its methods produced. PGE's non-traditional screens were valuable here as a way to focus on key portfolio attributes, but in the future PGE should work closely with stakeholders to gain broad understanding of significant non-traditional screens before PGE uses a specific criteria as a constraint in modeling or as a screen in scoring.

We generally agree with PGE's selection of a preferred portfolio of non-emitting capacity and limited renewables. PGE's modeling shows a capacity need and substantial ratepayer benefits to some level of tax credit-eligible renewables. With Staff's scrutiny of this IRP, PGE tested alternative market forecasts, low loads, rapid technology development and deployment, and tax credit extensions, and found that its portfolio selection remained appropriate. We appreciate the work that PGE did to ensure that these benefits were durable across a wide variety of futures and risks by considering a high technology future with more significant renewable resource cost reductions and low market prices, intergenerational equity analysis to allow us to see the tradeoffs between savings over the long term and rate pressure in the near term, and the market energy position to avoid unreasonably long energy positions.

PGE should continue to work with Staff and stakeholders to explore how to model the cost and risk tradeoffs of energy additions in this environment. As PGE continues to refine its modeling of economic performance of existing and new resources, PGE also will need to consider future changes in energy markets, such as the potential transition to security-constrained, economic dispatch day-ahead markets, and how its resources will perform against market-wide clearing prices. In addition, PGE will need to continue to evaluate and balance the tradeoffs between more certain near-term rate impacts and less certain long-term projected cost savings. We note that PGE will also need to continue to support its proposal as it moves forward in changed circumstances, assessing whether the impacts of the COVID-19 pandemic are a material change to forecasts, needs, and its customers' tolerance for near-term rate pressure.

We note that PGE's explanation that alignment with its corporate emission reduction goals led it to construct a preferred portfolio with only "non-emitting" capacity resources is not a persuasive justification for its portfolio, in and of itself. Corporate strategy, without more, is not an appropriate justification for resource selection. However, our IRP guidelines describe 'public interest' as including state and local policies and we recognize and support decarbonization as a goal of the State of Oregon, as expressed in legislative policy and executive order, as well as the policies of the largest communities in PGE's service territory.[22] Fortunately, declining costs and new opportunities for non-emitting capacity, joined with the longstanding risk of carbon policy costs and the new risk of relatively large-scale customer defection for clean energy options, enable PGE to focus the portfolio on non-emitting resources without deviating from least-cost, least-risk principles. In short, although PGE's corporate emission reduction goals do not, in and of themselves, justify PGE's proposed resource acquisition approach, we appreciate that its goals appear to align well with the policy prevailing in its service territory, its customers' expressed goals, and the resource options available to the company.

Ultimately, we find that the key attributes of PGE's preferred portfolio, which are a defined amount of new low cost, tax credit eligible renewable resources and a larger amount of non-emitting capacity, are reasonable.

B. Action Plan

PGE's action plan does not seek procurement of the specific supply side resource types and quantities identified in the preferred portfolio. Instead, PGE explains that its action plan is designed to use technology-neutral procurement processes to allow the company to pursue resources with the key attributes identified in the preferred portfolio. PGE identifies customer resources (energy efficiency and distributed flexibility) and capacity from renewables, existing resources, and new non-emitting dispatchable resources as the key attributes that align with its resource needs.

1. Customer Resource Actions

PGE's action plan contains two customer resource actions: one for energy efficiency and one for distributed flexibility. Action Item 1a states that PGE will seek to acquire all cost-effective energy efficiency and cost-effective and reasonable distributed flexibility. In PGE's 2019 IRP filing, this amount was forecast by Energy Trust as 157 MWa by 2025. Action Item 1b states that PGE will seek to acquire all cost-effective and

[22] Executive Order No. 20-04.

reasonable distributed flexibility (also referred to as demand response). In PGE's 2019 IRP filing, this amount was forecast as 211 MW summer response, 141 MW winter response, 137 MW dispatchable standby generation, and 4 MW dispatchable customer storage.

a. Comments

CUB discusses data centers, stating that a large part of PGE's industrial load forecast is from data centers, and that future IRPs should evaluate energy efficiency opportunities at data centers.

On the distributed flexibility action item, NWEC requests a 20 percent stretch goal to the distributed flexibility goal and/or adding an open-ended request for proposals for distributed flexibility resources in the action item. PGE responded by stating that it will include a more thorough proposal with its flexible load plan in 2020. NWEC also requests that PGE address demand response program design to alleviate customer unease and uncertainty.

Staff asks that PGE's next IRP contain two long-term energy efficiency forecasts that calibrate a predicted adjustment of energy efficiency for the high and low load forecasts, as a comparison to the reference case developed with Energy Trust. Staff also asked PGE to work toward methods for modeling incremental energy efficiency that does not meet the cost-effectiveness threshold as a resource choice to be compared with other resources. PGE states that it is open to discussions with Staff and interested stakeholders regarding if and how IRP portfolio analysis could include the selection of additional EE measures beyond those found to be cost-effective.

b. Resolution

We acknowledge PGE's customer resource action items, with some additional conditions and directives generated from Staff and stakeholder feedback. We agree that it is important to understand how PGE's forecast would change with more aggressive energy efficiency measures, and also require PGE to explore the significant, cost-effective energy efficiency opportunities that may exist with data centers that are a significant component of industrial load growth. Action plan modifications and conditions that further these goals, as discussed among the parties and the Commission, are listed below.

We highlight the importance of PGE's flexible load plan in light of PGE's increasing capacity needs; if the flexible load plan does not sufficiently advance stakeholder understanding of PGE's approach to demand-side resources as a comparable resource to supply-side capacity, we will be prepared to direct PGE to explore other more transparent alternatives for acquiring demand-side resources, such as, but not limited to, a targeted request for proposals.

Staff and PGE agreed to the below modifications, which we accepted:

- Before the next IRP, PGE will work with Energy Trust and stakeholders to explore the potential for PGE's portfolio modeling to select incremental energy efficiency that is least cost, least risk, beyond Energy Trust's baseline forecast.
- Before the next IRP, PGE will work with Energy Trust to develop high and low energy efficiency forecasts that have internally consistent assumptions with the load scenarios,
- Before the next IRP, PGE and Energy Trust will conduct a workshop regarding data center load and energy efficiency measures and to consider adoption of the Northwest Power and Conservation Council energy efficiency capacity value modifiers. Staff may request a study if needed.
- In the next IRP, PGE is to report on trends of sales by customer class and DER installments for 2015 through 2019.

2. Capacity Actions and Renewable Actions

As amended in PGE's final comments, PGE's capacity action provides that PGE will pursue dispatchable capacity through bilateral negotiations and through a RFP. PGE has already initiated bilateral negotiations, seeking cost-competitive agreements for existing capacity in the region. PGE plans to begin work on a non-emitting dispatchable RFP concurrently with the bilateral negotiations.

PGE's renewable action, as amended in final comments, provides that PGE will conduct a renewables RFP seeking up to approximately 150 MWa of new RPS-eligible resources that contribute to meeting PGE's capacity needs by the end of 2024. PGE includes four conditions: that the renewable resources must qualify for PTCs or the Investment Tax Credit (ITC); that the resources must pass a cost-containment screen; that the value of RECs generated prior to 2030 must be returned to customers; and that resources must meet the transmission requirements described in PGE's transmission addendum. PGE notes that the Renewable Action does not compel any procurement but allows PGE to consider up to approximately 150 MWa of renewable resources.

PGE filed a transmission addendum (also referred to as the Interim Transmission Solution) that proposes a pilot approach for allowing a wider range of transmission arrangements to be applied to non-dispatchable renewable resources. In the past, PGE has required long-term firm service for projects delivering to PGE's service territory. PGE states that it understands the limitations in the region and addressed those limitations in the Interim Transmission Solution by allowing for conditional firm products for 80 percent of a facility's output, and allowing short-term firm products for the remainder. Specifically, PGE would allow for Long-Term Firm, Conditional Firm Bridge (number of hours option), and Conditional Firm Reassessment (number of hours option). In an effort to provide early RFP scoring methodology to stakeholders, the Interim Transmission Solution describes a capacity scoring approach for the portion of the resource that would be served by long-term transmission, with a resource's expected output diminished for the number of hours of allowed curtailment under the conditional firm product.

In its final comments, PGE proposes size limits that would apply across all procured resources. For capacity, PGE proposes not to exceed PGE's identified 2025 reference case capacity need of 697 MW for the combined capacity contribution of all procured resources; PGE will refine that maximum following an updated needs assessment prior to any RFP. For energy, PGE proposes to constrain energy additions across the capacity action and the renewable action to approximately 150 MWa to align with the 250 MWa portfolio screen and the expectation that bilateral procurement will result in some energy additions.

For the RFP structures, PGE plans to consider dispatchable capacity resources and renewable energy resources in separate processes that are coordinated and conducted concurrently. PGE maintains that the key resource attributes are distinct and require RFPs with different resource requirements and non-price scoring criteria. PGE asserts that its procurement activities will be separate but explicitly coordinated with the portfolio size limit applied across all procurements.

a. Comments

Staff's primary recommendation is that the Commission not acknowledge PGE's renewable action item. Staff explains that PGE did not demonstrate an energy need relative to the traditional energy LRB nor an RPS need, and that PGE's market energy position analysis does not establish an energy need and sets an arbitrary threshold. Therefore, Staff does not support a standalone RFP for resources that may provide significant energy but not contribute meaningfully to PGE's capacity need.

Staff and AWEC state there is no need for PGE to run separate RFPs for renewable and capacity resources because renewable resources can compete on their own merits with other forms of generation in an RFP designed to meet PGE's capacity need as part of a least-cost and least-risk portfolio. AWEC states that, with separate RFPs, the bids would be subject to different analysis and it will be difficult to compare the bids across these RFPs on an apples-to-apples basis to determine whether PGE is selecting the least-cost/least-risk portfolio of resources.

Staff makes several recommendations for acknowledgment conditions in the event that the Commission acknowledges a standalone renewable resource procurement.

Staff's alternate recommendation is that PGE allow renewable resources to participate in the capacity RFP rather than conducting a separate renewables RFP. Staff explains that its primary concern is that PGE's approach is risky, in that it relies heavily on portfolio optimization that values resources based on a 30-year market forecast. Staff believes there are near-term risks to resource costs and resource performance that should be watched for in the RFP process.

PGE prefers to have separate RFPs but is open to Staff's proposal. PGE requests that, if the Commission shares Staff's concern, then the Commission could acknowledge the capacity and renewable actions and direct PGE to combine the two RFPs into a single solicitation.

Other commenters, including CUB and NWEC, express no strong position on the form of the RFPs, which CUB notes should be PGE's responsibility to manage. NWEC identifies certain principles that the procurement process, however designed, should meet. These include, among others, a full and consistent assessment of energy and capacity value for all bids, encouraging hybrid or composite resource bids where that provides additional value, considering the ability of renewable energy bids to provide flexibility and dispatchability, and maintaining competitive balance between company and developer bids.

National Grid and Swan Lake comment that PGE's two step capacity procurement plan may start too late (originally proposed for 2021), and end too early (capacity online in 2024-2025), to allow for resources with longer lead times. National Grid and Swan Lake state that PGE's IRP is one of the first in the region to include pumped storage in its preferred portfolio, with 200 MW per year in 2024 and 2025. National Grid and Swan Lake explain the current estimate from the turbine manufacturer is up to five years to design the pump-turbine generators and place them into service. PGE responds that its revised capacity action with concurrent procurements beginning in 2020 allows for long-lead time resources to participate in a RFP. PGE also explains that its capacity action is technology-agnostic between non-emitting capacity resources to allow for flexibility to adapt as information is gained about energy storage pricing through a RFP.

Finally, most parties responded to PGE's transmission addendum, stating that PGE's expanded set of transmission products is a good start but arguing that scoring needs to be based on data and needs to include more concrete detail. NIPPC states that PGE's transmission addendum is inadequate because it puts the onus on bidders to include service from their project to PGE's system, when PGE may be able to use its existing transmission rights. NIPPC asserts that PGE should accept all BPA conditional firm products (including conditional firm system conditions). Staff, Renewable NW, and NIPPC also disagree with PGE's proposed generic concepts for transmission scoring based on non-quantifiable aspects of risk and uncertainty. These parties also disagree with how PGE proposes to reduce a project's score based on the potential maximum hours of curtailment, instead of using information about historical actual curtailment.

b. Resolution

We acknowledge these action items subject to an additional condition that PGE must optimize its procurement approach, as described further below. As always, our acknowledgment recognizes that PGE must update its needs assessment and evaluate any material changes in the planning environment before carrying out its resource actions to ensure that the conclusions of its IRP analysis remain durable. In particular, at our March 16 public meeting, PGE agreed to update its needs assessment and to work with Staff on the specific inputs that will be updated, including minimum QF levels and coal retirements. At the meeting, we also made special reference to the need for PGE to examine the implications of the COVID-19 public health crisis and corresponding economic disruption that were just emerging in Oregon as we made our acknowledgment decision in this case.

PGE's action plan continues a trend of technology-neutral procurement actions oriented to the utility's needs and the key elements of the preferred portfolio, rather than actions to procure the specific resource types in amounts set forth in the preferred portfolio. We continue to approve of this approach, given that we must be open to the opportunity for today's dynamic technology development and pricing to improve customer outcomes by securing lower cost results from RFP portfolios that diverge from the modeled technologies in the IRP preferred portfolio. Although we recognize that this approach challenges our traditional understanding of the sequential nature of the IRP and RFP, encouraging the processes to become iterative and overlapping, the IRP continues to provide a robust opportunity to test the general direction of the portfolio and to refine which components of the analysis are most significant and therefore most important to watch in the RFP and succeeding cost recovery proceedings.

PGE's supply-side action plan presented a high-level procurement approach. Two areas of tension arose in connection with PGE's approach. The first concerns PGE's plan for procuring capacity, and the second relates to portfolio optimization between its dispatchable capacity and renewables that contribute both capacity and energy.

PGE's capacity procurement plan began, during the pendency of our IRP review, with a bilateral procurement process to determine how much of PGE's capacity need could be met from shorter-term arrangements with lower cost, existing resources. We support PGE using this method to seek the lowest cost reliability resources available, but also recognize the competing value that longer-term commitments to new capacity resources may offer given the likelihood of PGE's ongoing capacity needs and the likelihood of capacity scarcity in the region over the same term. We appreciate PGE's agreements to both accelerate the new capacity RFP and to make accommodation for long-lead time resources. For the latter, we conclude that an anticipatory waiver of our RFP rules is not necessary for PGE to fully and fairly evaluate long-lead time resources, but we remain open to such a waiver in the future if PGE determines that one is necessary.

We dedicated significant attention to the second area of tension—the role of renewable resources in contributing capacity and energy to an optimized portfolio. We considered the risks of PGE's renewable procurement and found that PGE did enough work to reign in its model to limit many risks. We concluded that PGE's modeling shows significant customer benefits from a portfolio that includes an optimized combination of near-term, low-cost renewables and non-emitting capacity resources. We specifically recognized the value of tax-credit enabled renewable resources to contribute to a least-cost, least-risk portfolio. We agree that energy additions should be constrained, and that PGE established 150 MWa as an appropriate energy cap to maintain across the RFPs, depending on the energy added in its bilateral procurement. We noted that PGE should justify whether its RPS compliance strategy requires it to secure RECs in the near term and to explain the cost-benefit tradeoffs for customers.

We remained uncertain whether PGE's proposed procurement methods (two separate RFPs, with expected level of capacity contribution in the renewables RFP) are best suited to achieve an optimized portfolio, and we conditioned our acknowledgment of both the renewables and the capacity action on PGE optimizing the renewables RFP with the capacity RFP to achieve the goals of the preferred portfolio. PGE may achieve this by combining the procurements to produce an optimized portfolio that achieves the goals of the preferred portfolio, or providing further justification for how separate procurements will be coordinated to improve our confidence that they can produce an optimal portfolio. We direct PGE to make a filing in the IE docket that explicitly addresses the tradeoffs between separate and combined RFP formats and explains how energy and capacity will be evaluated in either procurement format. If PGE retains the two-vehicle procurement approach it will need to explain how its scoring criteria address the risk that the two procurements may not lead to an optimized portfolio.

In the event that PGE moves forward with a standalone RFP, we considered two of Staff's recommended conditions that would apply to a company-owned resource. We declined to bar PGE from submitting a benchmark resource into the RFP. Within RFP design, we will ask the IE to specifically examine performance risk, to advise whether the RFP analysis tilts towards favoring a company-build, and to analyze potential higher near-term rate impacts due to a company-owned resource. We recognized that PTC realization is a key benefit shown in PGE's economic analysis. We stated that, if PGE pursues a company-owned resource, our acknowledgement is based on an assumption of the value of PTCs flowing through to customers. We further noted that the IE will need to make any PTC risk very visible in its RFP analysis.

Finally, we observe that transmission will be a significant constraint on the resources PGE will be able to consider for inclusion in an optimized portfolio. Although we do not reach any conclusions about PGE's transmission addendum here, we appreciate PGE's efforts and stakeholders' feedback in this area. In the IE docket we will take up these issues and seek additional information about PGE's transmission rights and what types of transmission arrangements are suitable for PGE's procurement.

We do not reach a conclusion as to whether PGE provided the level of scoring and associated methodology that, under our new RFP rules, would enable them to move directly to filing an RFP. Under the circumstances, where PGE's procurement approach was a significant area of discussion in our acknowledgment decision and where external timelines do not force PGE to move to an RFP immediately, we will depend on substantive discussion of the RFP format, eligibility criteria, scoring and selection methodology, and transmission arrangements in the IE docket. For these procurements, we agreed with Staff that PGE will need to engage in a rigorous process to establish RFP details, clarify key attributes including dispatchability and transmission requirements. During the RFP process we will endeavor to provide more clarity on how we interpret OAR 860-089-0250. We will aim to explain what information about scoring and associated modeling is required in an IRP to avoid the extra step of a workshop on scoring and methodology in the IE selection docket.

IV. ORDER

IT IS ORDERED that the Integrated Resource Plan filed by Portland General Electric is acknowledged with conditions as described within this order.

Made, entered, and effective May 06 2020.

Megan W. Decker
Chair

Letha Tawney
Commissioner

Mark R. Thompson
Commissioner