Portland General Electric
121 SW Salmon Street · Portland, Ore. 97204

October 17, 2019

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street, Ste. 100
P.O. Box 1088
Salem, OR 97308-1088

RE: UM 1953 Portland General Electric Phase II Reply Testimony

Portland General Electric hereby submits reply testimony and accompanying exhibits to provide additional information regarding PGE's proposed green tariff program. Enclosed for filing in the above referenced matter is:

- PGE / 600 –Testimony of Brett Sims and Jay Tinker
- PGE / 601 –PGE's Press Release Dated August 21, 2019
- PGE / 602 - PGE's Response to OPUC Data Request No. 022
- PGE / 603 - PGE's Response to OPUC Data Request No. 053
- PGE / 604 - PGE's Response to OPUC Data Request No. 051
- PGE / 605 - PGE's Response to OPUC Data Request No. 040
- PGE / 606 - PGE's 2019 Integrated Resource Plan Addendum

Please direct all formal correspondence and request to the following email: pge.opuc.filings@pgn.com.

Sincerely,

Robert Macfarlane

for Karla Wenzel
Manager, Regulatory Policy and Strategy

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I. Introduction and Summary

Q. Please state your names and current positions.

A. My name is Brett Sims. I am the Director of Commercial, Strategy Integration and Planning for Portland General Electric Company (PGE or Company).

My name is Jay Tinker. I am the Director of Regulatory Policy and Affairs at PGE.

Our qualifications are provided in PGE Exhibit 200.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to respond to the Opening Testimonies of the Public Utility Commission of Oregon (OPUC or Commission) Staff (OPUC Staff or Staff), Renewable Northwest (RNW), the Oregon Citizens' Utility Board (CUB), the Northwest and Intermountain Power Producers Coalition (NIPPC), PacifiCorp, and Walmart. We refer to these parties collectively as Parties.

The purpose of this testimony is also to clarify and supplement certain aspects of PGE's Phase II opening testimony in which we ask the Commission to:

- Adopt a new set of Guidelines to be used for determining whether a green tariff is in the public interest, replacing the Nine Conditions adopted in Order No. 16-251. PGE proposes a refined set of seven Guidelines;
- Raise the participation cap on PGE's Green Tariff, the Green Energy Affinity Rider (GEAR or Schedule 55) to a total of 500 MW;
- Acknowledge that the breadth of risk, beyond that discussed in our Phase I testimony, brought to PGE by entering a PPA and by a green tariff program should be borne by subscribers via the risk adjustment fee;

- Address the applicability of the Competitive Bidding Rules to this program and the interactions with Integrated Resource Planning processes; and
- Affirm that PGE's approach to addressing Green Tariff interactions within the Integrated Resource Plan (IRP) is reasonable.

Q. Does PGE have any additional requests of the Commission?

A. Yes. PGE further asks the Commission to:

- Clarify PGE's authorizations associated with utility ownership of a resource for the GEAR; and
- Affirm that all changes made to PGE's Green Tariff during this Phase II proceeding, including the expanded risk adjustment fee, will apply to all new subscription agreements[1] under the approved 300 MW GEAR cap.

Q. How is your testimony organized?

A. We have grouped topics into the following sections:

1. <u>Enrollment Update</u>: Staff has requested a status update of enrollment levels in the first offering of the Green Tariff under the approved 300 MW program cap, for context of PGE's regulatory Phase II requests.
2. <u>Updated Guidelines to Replace the Nine Conditions</u>
3. <u>GEAR Program Design</u>
4. <u>GEAR Resource Procurement and Long-Term Planning</u>

[1] Changes would apply to new subscriptions occurring after the Commission Order date.

II. Enrollment Update

Q. By offering this additional information, is PGE seeking to re-open Phase I of the docket that concluded with Commission Order 19-075 and allowed the offering of the first 300 MW of PGE's Green Tariff?

A. No. In providing this information, PGE is responding to Staff's request for an update and Parties' interests in enrollment.[2]

Q. What is the current level of enrollment in PGE's Green Tariff?

A. As of October 17, 2019, the Green Tariff has subscriber enrollment representing approximately 60 MW in the PGE Supply Option and approximately 100 MW in the Customer Supply Option (CSO).

Q. Please reconcile this level of enrollment with the statement made in PGE Exhibit 500, page 6, "Customers filled the subscription window for the 100 MW available in [the PGE Supply Option] in under two minutes."

A. That statement reflected the level of enrollment for the PGE Supply Option, documented by non-binding letters of interest, when enrollment first opened in May 2019, and at which point there had been no enrollment in the CSO. The current level of enrollment reflects increased demand as actual customer agreements were executed over the next several months; under the final agreements, total enrollment increased when some customer demand elected for the CSO.

Q. What new renewable resource or resources will support this enrollment?

A. An approximately 160 MW resource will serve both the PGE Supply Option and the CSO enrollment, and it represents the most viable least cost, least risk PPA resource for customers under both supply options. This resource brings a notable economic benefit to all customers; at

[2] This enrollment information is also provided in PGE's Compliance Filing dated September 13, 2019.

approximately 160 MW, it is significantly more cost effective than a 35 MW resource that a single large customer may have otherwise sought[3].

Because the PPA is not yet executed, the resource cannot be named at this time. We can, however, disclose that it is a qualifying renewable project in Oregon that will be operational by the end of 2021.

Q. What have subscribers' reactions been to their enrollment in the Green Tariff?

A. Subscribing customers, in both options, are thrilled to participate in this program and drive additionality of renewables in the Pacific Northwest. Their enthusiasm for being part of the program is captured in customer quotes in PGE's press release on August 21, 2019 included as PGE Exhibit 601.

III. Updated Guidelines to Replace the Nine Conditions

Q. Why is PGE proposing to modify the Nine Conditions imposed by Commission Order No. 16-251 and outlined again for PGE in Order No. 19-075?

A. In PGE's Phase I Cross-Answering Testimony, we stated that the examination of broader programmatic concerns including "… whether [the nine conditions] continue to represent best practice for the purposes of offering voluntary renewable products"[4] should be addressed in Phase II. The Commission agreed. In Order No. 19-075, the Commission requested to "review and reconsider the nine conditions"[5] in this Phase II proceeding. The Commission wrote, "We see a need to assess changes in Oregon's competitive electricity supply market and in the renewable energy development marketplace since 2016 as part of a reconsideration of the nine conditions."[6]

[3] A 35 MW resource is approximately the size needed to meet the demand of a single 10 MWa customer.
[4] PGE/400 Sims – Tinker/6: 1:3
[5] Order No. 19-075 Page 8
[6] Id.

We discussed PGE's proposed Guidelines to replace the Nine Conditions in PGE Exhibit 500 and Parties have responded to PGE's proposed Guidelines. We now provide an update as follows:

A. Condition 1 (RPS Definitions for Bundled RECs Apply)

Q. PGE proposed leaving Condition 1 unchanged in new Guideline 1. Is PGE proposing to change its recommendation based on Parties' responses to its proposal?

A. No. Condition 1 states:

> Renewable Portfolio Standard (RPS) definitions of resource type, location, and bundled Renewable Energy Certificates (RECs) must apply to VRET[7] products.

Staff, RNW, PacifiCorp, and NIPPC support PGE's proposal to leave this guideline unchanged. CUB requested a modification to allow incorporation of resources with battery storage. RNW also separately, albeit outside of the conditions/guidelines, requested inclusion of resources with battery storage in PGE's Green Tariff.

PGE's recommendation for Guideline 1 has not changed. At this time, PGE does not think it is appropriate to alter this guideline away from the fundamental objective of having green tariffs be programs that allow customers to purchase bundled RECs and thereby drive the development of additional renewable power generation.

B. Condition 2 (Retirement of RECs on Behalf of Participants)

Q. PGE proposed a slight modification to Condition 2 in the new Guideline 2. What were Parties' responses to that proposal?

A. Condition 2 states:

> Voluntary renewable energy options only include bundled REC products. Any RECs associated with serving participants must be retired by or on behalf of participants, unless the participants consent to RECs being retired by the utility or developer.

[7] Voluntary renewable energy tariff or green tariff

PGE's proposed Guideline 2 states:

> Voluntary renewable energy options include only bundled REC products. Any RECs associated with serving participants must be retired by or on behalf of participants.

Staff, RNW, CUB, and PacifiCorp support PGE's proposal requiring RECs to be retired by or on behalf of the participant. NIPPC did not individually address PGE's proposed Guideline 2 but advocates for no modification of any of the original Nine Conditions.

CUB also advocates for a modification "to state that any load served by renewable project eligible for a green tariff should be reduced from the utility's RPS requirements."[8] CUB's position is that customers' voluntary participation in a green tariff should reduce the utility's renewable procurement obligations for the RPS.

Q. Is PGE proposing to further modify its proposal?

A. No. PGE maintains its original recommendation for Guideline 2, which strikes the REC "gifting" option. In further support of this modification, RNW, in its Opening Brief for Phase I, discussed the original "gifting" option's inconsistency with House Bill (HB) 4126, which forbids utilities from using RECs for RPS compliance.[9]

CUB's recommendation to use green tariffs to reduce utility compliance needs would also diminish the impact that customers desire: Customers enrolling in green tariff products are intentionally seeking a significant tangible impact on renewable development above and beyond the levels already mandated by law to achieve RPS compliance.

Q. Without modification of Condition 2, is there a risk that, as CUB proposes, "PGE will be adding renewables to serve load which is already served by renewables"[10]?

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[8] CUB/200, Jenks/12-13
[9] RNW Opening Brief Page 9
[10] CUB/200 Jenks/12: 23-24

A. No. PGE does not agree that there is a risk of "double serving" load from renewable resources. PGE's position is based on the following three reasons:

- PGE anticipates customer demand in the program will diminish over time as PGE's system becomes increasingly decarbonized. In the future, PGE expects that customers will meet their organizations' sustainability targets within their base cost-of-service (COS) schedules. As we saw, in the first offering of the Green Tariff, most customers enrolled at a level to complement, not "double serve," the level of renewables within PGE's base service resource mix.
- The proposed 500 MW program cap is sufficiently small relative to PGE's load that the current RPS goal for 2040 and beyond to serve 50 percent of load with renewable resources could not drive adoption of renewables to serve load already being served by the Green Tariff.
- If the Oregon legislature accelerates the adoption of renewables in PGE's system such that PGE would be required to acquire additional renewable generation to serve the load already served by the Green Tariff, PGE would discontinue offering new tranches of the program, even if it has not reached the program cap, instead focusing on procurement for the entire system.

At this time, PGE does not believe the concern regarding "double serving" is warranted. If structural changes do occur, such as changes in Oregon law or policy, the Green Tariff program could be altered accordingly. Until such time, guardrails exist to prevent the outcome CUB has identified as a concern.

C. Condition 3 (Defining Incremental Resources)

Q. PGE proposed modifying Condition 3 in its Guideline 3, to bring the guideline up-to-date, maintaining the intention for green tariffs to support new renewable development. What were Parties' responses to that proposal and has PGE's recommendation changed?

A. Condition 3 states:

> The year that a voluntary renewable energy program eligible resource became operational should be no earlier than 2015.

PGE's proposed Guideline 3 states:

> The year that a voluntary renewable energy program eligible resource became operational should be no earlier than *one year prior to program enrollment* [change italicized].

Staff, CUB, RNW, and PacifiCorp all support PGE's proposal. NIPPC's opening testimony does not individually address PGE's proposed Guideline 3 but advocates for no modification of any of the original Nine Conditions.

PGE continues to recommend updating this guideline to drive new renewable development, which is the fundamental intention behind green tariff products nationwide. For its GEAR, PGE defines incremental resources more precisely, and we discuss this later in our testimony.

D. Condition 4 (PGE Program Cap)

Q. PGE proposed modifying Condition 4 in its Guideline 4, to set the PGE program cap to 500 MW. What were Parties' responses to that proposal?

A. Condition 4 states:

> The voluntary renewable energy program size is limited to 300 MWa for PGE.

PGE's proposed Guideline 4 states:

> The voluntary renewable energy program size is limited to 500 MW for PGE.

PGE's modification of this Condition, reducing the cap from 300 MWa (units of energy) to 500 MW (units of capacity), reduces PGE's generic green tariff cap to reflect the cap of its specific tariff (Schedule 55 or GEAR), for the purpose of streamlining requirements.[11]

Today PGE has Commission approval to procure and offer up to 300 MW of nameplate resources through the GEAR, and as PGE explained in its opening testimony, PGE is seeking an expansion of the GEAR to a total program cap of 500 MW.

RNW supports and NIPPC does not oppose[12] PGE's request for raising the 300 MW cap on the GEAR to 500 MW. Staff and CUB both raise objections to raising the 300 MW cap on the GEAR at this time; both parties advocate waiting for "operational experience" of the first 300 MW before raising the cap.

Q. Please explain the difference between a cap expressed as energy (average megawatts) and one expressed in capacity terms (megawatts).

A. A cap expressed as energy (MWa) reflects the average expected generation of the green tariff resource(s), whereas a cap expressed in terms of capacity (MW) reflects the resource(s) nameplate capacity or maximum power output. PGE does not have a preference of expressing the cap in one unit or the other but simply notes the distinction, as it seems to cause confusion. A 300 MW resource is not equivalent to a 300 MWa resource. For example, a 300 MW Columbia River Gorge wind resource would be approximately 100 MWa, whereas a 300 MWa equivalent Gorge resource would be approximately 900 MW.

[11] The full 300 MWa allowed under Condition 4 would not be available to PGE without Commission approval of a similar cap for a specific tariff. If or when PGE seeks to raise the tariff cap going forward, the guideline cap would be simultaneously raised.

[12] NIPPC does not oppose the PGE's Green Tariff cap because it is less than the PGE's Direct Access cap, and NIPPC advocates that UM 1690 Condition 6, the "mirror" condition, remain in place (NIPPC/200, p17-18).

Q. PGE has not yet reached the existing caps of either of the 100 MW PGE Supply Option or 200 MW CSO. Why are you seeking to raise the program cap now?

A. Raising the program cap now would allow PGE to be more responsive to customer demand. PGE has proposed a 100 MW increase to each of the PGE Supply and Customer Supply Options. PGE is in a unique commercial situation with the Green Tariff, needing to either:

- Identify customer demand for a program that has not yet been approved, that may evolve during the regulatory process, and for which pricing is uncertain as a result of being dependent upon the resources that will be available in many months when the regulatory process is complete and implementation can begin; or
- Complete the regulatory approval process first and offer the program to customers once there is more timing and price certainty.

PGE's preference is the latter, which offers customers better service and experience.

Additionally, regulatory certainty improves negotiating leverage for resource procurement, which would benefit customers and encourage customer participation to drive the decarbonization goals.

Q. When does PGE expect customer demand to hit the existing 300 MW cap?

A. Based on the enthusiastic response from customers in the first offering, and that PGE has already heard from several customers interested in a second offering, PGE expects similar strong demand in future Green Tariff offerings. Market response, however, will ultimately depend on price and specific resource characteristics, which in the current tax credit incentive environment, depend heavily upon speed of deployment. Consequently, it is difficult to precisely estimate the level of customer demand in advance of greater certainty related to regulatory approvals, timing, and resource pricing.

Q. What specifically would PGE do if the Commission allowed an increase in the cap as requested?

A. PGE would solicit pricing from renewable resource developers for resources to better determine pricing. After doing so, PGE would proceed with another PGE Supply Option enrollment window to determine customer interest, similar to that implemented for the first offering. This second step would depend heavily on the first step as indicative pricing, timing, and resource information is needed in order to provide the required information to interested customers. Once PGE has assessed the potential demand, negotiations with the least cost, least risk resource would begin, and PGE would eventually issue subscription agreements to customers. We note that, meanwhile, enrollment for CSO is ongoing and may continue until the cap is reached.

Q. In response to Staff and CUB's recommendation, what would be the impact to customers if the Commission waited for more operational experience of the first tranche of the Green Tariff before raising the program cap?

A. Since the first tranche will not be operational until the end of 2021, the Commission would not be able to evaluate the program and approve an increase to the program cap until 2023 (allowing minimal time for the operational experience and regulatory process). This would mean that PGE would not be able to perform customer outreach, enrollment, and procurement until 2023 and 2024; and the resource would not be constructed until 2024 or 2025.

Because PGE understands customers' urgency for meeting their sustainability goals, PGE believes this timeline would be unacceptable to customers. Not only would customers lose potential for the current economic benefits of the Production Tax Credits and Investment Tax Credits, they would not have the offering they have requested (Green Tariff) to help them achieve their organization's sustainability targets.

Q. Do you agree with Staff's characterization of the 500 MW as "36% of PGE's non-residential load in the Company's 2020 forecast"[13]?

A. No. Staff made its calculation based on an unreasonable assumption that the 500 MW Green Tariff resources would be operating at a 100% net capacity factor. No resource, renewable or otherwise, generates at full capacity all hours every year. Even in the best-case scenario, regional renewable resources will have capacity factors below 30% or 45%, whether solar or wind, respectively, because the sun does not always shine and the wind does not always blow.

Staff should have characterized the magnitude of the Green Tariff program using a realistic capacity factor, which, as Staff subsequently explains, is closer to 30% and which results in the 500 MW serving less than 7% of 2020 total load on an annual energy basis.[14]

Q. What information and insights will operational experience provide?

A. No revelatory information will be derived from operational experience and particularly, not from near-term operational experience. PGE has described in testimony how the program works, how the credits will be calculated, how the program interacts with long-term planning, and importantly, how cost-of-service customers are protected from cost shifting. PGE has also provided Staff the data used for the subscriber fee calculations in its Compliance Filing dated September 13, 2019.

Staff writes that they need "empirical evidence" to reach "an ultimate conclusion on the impact to power costs and resource planning."[15] In reply, PGE notes that an "ultimate conclusion" cannot be made until the end of the resource's contract life; one or even two years of program operation will provide an incomplete picture. A short-term view of operational experience may

[13] Staff/300 Gibbens/5-6
[14] Using the same reference 2020 load forecast as Staff, from UE 359 – PGE/100, Niman et al./29 Table 3.
[15] Staff/300 Gibbens/5: 4-7

highlight only the normal course of business interannual variability expected with renewable resource generation and power markets.

As a 500 MW program serving less than 7% of PGE's load, the potential impacts to power costs and long-term resource planning are very limited, and the Commission should not further delay Green Tariff growth—suspending customer access to their requested option to drive additionality of renewable generation—based on an unsupported assumption that operational experience will provide insights not currently available.

Q. Is there a path forward that allows the Commission to expand PGE's program now while respecting Staff's and CUB's concerns regarding program expansion?

A. Yes. A path that allows PGE near-term expansion of the program to meet customer needs would be for the Commission to allow PGE flexibility to offer PGE Supply or Customer Supply Option within the approximately 140 MW available under the current 300 MW cap, allocating to either option according to customer demand. With this flexibility, PGE could consider all customer demand in aggregate and subscribe the remaining 140 MW for PGE Supply Option, or the same amount of capacity could be allocated to customers interested in the Customer Supply Option. PGE believes this would create sufficient flexibility to meet anticipated near-term customer demand.

In addition, PGE would be amenable to reporting back to the Commission and Parties on customer interest in its Green Tariff, and other identified learning from implementing the program. Such reporting could include number of customers enrolled under each option, the available capacity under the program cap, the performance of the generation resources, and other updates. Should the Commission authorize this alternative, PGE would request that a future advice filing be used to increase the cap, if needed, rather than expanding this docket to an additional phase. An advice filing would allow sufficient time for review, with the option of a more targeted investigation that could be expedited.

Q. Why is PGE limiting the proposed cap increase to 500 MW, as opposed to something similar to the Direct Access cap of 300 MWa (which is equivalent to over 650 MW of wind or over 1000 MW of solar)? In other words, why have a cap at all?

A. PGE recognizes the GEAR is a not a program that will have unlimited demand since it is a premium product charged above cost-of-service base rates and because, as PGE's system becomes increasingly decarbonized, customers will meet their sustainability targets with their base cost-of-service resource mix.

E. Conditions 5 and 6 (Explicitly Linking Green Tariffs to Direct Access)

Q. PGE proposes removing Conditions 5 and 6 in its proposed updated Guidelines. What were Parties' responses to that proposal?

A. Condition 5 states:

> Voluntary renewable energy product design should be sufficiently differentiated from existing direct access programs.

Condition 6 states:

> Voluntary renewable energy product offering terms and conditions (including the timing and frequency of offerings), as well as transition costs, must mirror those for direct access. PGE may propose terms and conditions that differ from current direct access provisions but must propose changes to their direct access programs to match those changes.

Parties have mixed reactions to PGE's proposal; several parties recommend preservation of Condition 5 and most parties support modification or removal of Condition 6.

PacifiCorp supports PGE's removal of Condition 5. CUB recommends that Condition 5 be retained. Staff and NIPPC oppose PGE's removal of Condition 5, both stating that although PGE's current program is sufficiently differentiated, other future utility green tariff programs may not be.

CUB and PacifiCorp support removal of Condition 6. Staff proposes a modification rather than removal of Condition 6. NIPPC advocates for retaining Condition 6.

RNW writes that removal of both Conditions 5 and 6 "may be acceptable provided that any utility offering a green tariff, PGE in this case, offer regular updates to the Commission regarding the relative success of the green tariff option and the Direct Access option" because "some Commission oversight is necessary to ensure that both green tariffs and Direct Access remain competitive programs." [16] RNW also considers the possibility of modifying Condition 6.

Q. PGE's GEAR satisfies Condition 5. Will all possible future utility green tariff offerings inherently satisfy this "sufficiently differentiated" condition?

A. No. There is no statute or barrier preventing Electricity Service Suppliers (ESSs) from developing products to mimic utility green tariffs (i.e., physical, bundled REC products) and thereby limiting the ways in which utility green tariffs can be designed to be sufficiently differentiated.

Having ESSs develop their own versions of these products could mean positive development for a competitive marketplace; rivalry is a key characteristic of a competitive marketplace. However, the current Condition 5 is written to allow ESSs to control that market and suppress that competition.

[16] RNW/300, O'Brien/9

Q. What happens when an ESS markets a product to mimic a utility green tariff?

A. Once ESSs have developed products to mimic utility green tariffs, utilities will have increasingly limited options to develop products that satisfy Condition 5. As NIPPC asserts in its testimony, "An ESS can offer the same services as any 'narrow' program [like the GEAR]."[17] NIPPC also writes, "If PGE can design a VRET program that holds interest for some customers surely other entities active in the Direct Access program could do the same."[18] Once an ESS does develop such a program, Condition 5 will jeopardize green tariff programs.

Q. Why would this be a problem?

A. There are no ramifications for an ESS if it develops a program that is not sufficiently differentiated from an existing green tariff. There are, however, ramifications for the utilities when the utilities subsequently seek to develop green tariff offerings. For example, if an ESS develops a program that offers customers a subscription-based, fixed-fee bundled REC product like the PGE's Green Tariff, the existing Condition 5 may imply that the PGE's Green Tariff program could not be expanded, due to no longer being sufficiently differentiated from an existing Direct Access program. Such an outcome would not align with customer needs, the original intent of the GEAR, or state policy objectives.

Q. Does Condition 5 support the objective of developing a competitive retail market?

A. No. Condition 5 creates an environment where ESSs can effectively block utility participation in segments of the retail market. This is not consistent with the definition of a competitive marketplace.

[17] NIPPC/200 Kahn/13: 2-3
[18] NIPPC/200 Kahn/10-11

Q. Does Condition 6 give utilities clear direction for how to design green tariff programs?

A. No. Green Tariff and Direct Access programs are operated by different types of entities, with different rules, regulations, and objectives[19], and all terms and conditions will never be identical. For example, because PGE's Green Tariff is based on a customer remaining on cost of service, it does not include transition charges. As written, Condition 6 indicates that PGE's Direct Access program should be modified to eliminate transition charges, which were specifically designed to reduce cost shifting from Direct Access to cost of service customers. This type of explicit and unbending mirroring was not the intent of Condition 6. Instead, PGE believes the intent was to ensure the utility does not design a program calculated to undermine Direct Access participation.

An issue with implementation of Condition 6 is that it relies on the subjectivity of the evaluator to determine which terms and conditions must be "mirrored." In its testimony, NIPPC cherry-picks the terms and conditions to be "mirrored" to favor NIPPC members.

Q. Does Condition 6 support the objective of developing a competitive retail market?

A. No. By requiring actions be taken to homogenize the market offerings of such vastly different products, Condition 6 reduces competition and limits customer choices.

Q. NIPPC has identified three areas that should be mirrored between green tariffs and Direct Access. Please respond.

A. NIPPC has highlighted three specific issues that must be identical across the GEAR and Direct Access programs: calculation of capacity and energy credits, eligibility threshold, and

[19] Green tariffs have the narrowly focused objective of driving additionality of renewables whereas Direct Access offers broader customer choice that encompasses power from older and non-renewable generation resources.

program cap. If PGE were required to mirror its Green Tariff across NIPPC's three specific issues, the following implications would result:

- Calculation of capacity and energy credits – To mirror capacity and energy credits, charge Direct Access customers Resource Intermittency Charge (RIC) and Resource Adequacy Charge (RAD)[20] to account for the reliability services for which PGE's Green Tariff cost-of-service customers are paying. NIPPC, however, in its testimony proposes an irrational payment to Direct Access customers for the energy and capacity they "provide" by ***leaving*** PGE's system. NIPPC's proposal uses a false premise and completely ignores the cost shifting that Direct Access creates.
- Eligibility threshold – To mirror eligibility thresholds, increase PGE's Green Tariff customer eligibility requirements to customers with an aggregated load greater than 1 MWa for parity with Direct Access eligibility. Changing this eligibility threshold would satisfy NIPPC's request, but the negative consequence of this would be that it leaves customers between 1 kW and 250 kW (with aggregate load of at least 1 MWa) with no option for directly driving decarbonization through additional renewable generation.
- Program cap – To mirror the program caps, reduce the size of the Direct Access programs to mirror the 500 MW GEAR program cap. This translates to a value between 125 MWa and 175 MWa, which is below the current existing Direct Access cap of 300 MWa. NIPPC apparently wants the "mirroring" of program size be triggered selectively; NIPPC advocates for increasing the size of the Direct Access program to match any increase in the Green Tariff, yet currently, even without including short-term customer opt-outs or the

[20] UE 358 PGE/100

forthcoming New Load Direct Access program (with its 119 MWa cap), the Long Term Direct Access program cap is three times larger than the Green Tariff program cap.

The implications of mirroring across these three issues, as described above, serve to emphasize the subjectivity of Condition 6 and the obstacle this condition presents in advancing and expanding customer options.

Q. NIPPC asserts that PGE should not "be permitted to provide any VRET type program with terms and conditions that its competitors are unable to provide."[21] Do you agree?

A. No. This quotation from NIPPC's testimony claims PGE is using GEAR terms and conditions to block ESS participation in this segment of the market. This claim is untrue; having different terms and conditions does not prevent ESSs from providing customers renewable power options, and indeed, over the past years, many customers have elected out of PGE's cost-of-service for service by an ESS.

Furthermore, different terms and conditions *should* apply to green tariff programs and the Direct Access program because not only are these programs distinctly different customer options—and customer optionality is a feature of a competitive marketplace—but also the programs were created in different times for different reasons. Direct Access was created in 2002 to restructure the electric industry and offer commercial and industrial customers choice in their electric service provider. There are more sophisticated customers who elect Direct Access with the confidence that they can manage the market risk, and thus benefits outweigh the risks. Other customers are more risk averse, and prefer to continue service with PGE, depending on the utility to manage market risk for them. Customers in this latter category should not be forced to exit their chosen cost-of-service framework to achieve their organization's climate goals.

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[21] NIPPC/200, Kahn/11: 1-3

Conversely, the distinct reason green tariffs are underway across the country is to respond to the climate crisis and give utility customers the ability to accelerate decarbonization of the electric system.[22] Many customers want to make tangible progress toward climate goals, and green tariffs provide them the option to access new renewable generation resources while continuing PGE's service, taking advantage of the other benefits the utility service provides.

Direct Access is a long-term customer option—the Direct Access program has no sunset date—whereas green tariff programs are anticipated to be a shorter-term expedient for utility customers until the penetration of renewables in the utility's base resource mix expands in compliance with Oregon's increasing RPS.

Finally, as PGE noted throughout Phase 1 of this docket, PGE's Green Tariff is *in addition* to cost-of-service, not a replacement for it. The replacement concept was one of the concerns Condition 6 was designed to address and it is not applicable here.

Q. Please respond to NIPPC's testimony stating that PGE's program has "terms under which it can 'lock out' competition from providing generation service to commercial and industrial customers."[23]

A. PGE assumes that NIPPC is referring to the term commitment associated with the GEAR when accusing PGE of being able to "lock out" competition. As detailed at length in the record for Phase 1, the term commitment is a requirement to avoid cost shifting to other customers and to manage the risk of new renewable resource PPA terms. The Commission acknowledged this by allowing PGE to offer shorter subscription terms and to include a risk premium to ensure that no cost-shifting occurs. Despite NIPPC's characterization, customers have choices to: a) participate

[22] World Resources Institute, Emerging Green Tariffs in US Regulated Electricity Markets, October 2018, https://wriorg.s3.amazonaws.com/s3fs-public/emerging-green-tariffs-in-us-regulated-electricity-markets_1.pdf
[23] NIPPC/200, Kahn/12: 10-12

in the GEAR, and b) elect their desired contract length. Any commercial or industrial customer who wishes to pursue Direct Access will either elect to forgo participation in the Green Tariff, select a reduced term length, or accept financial responsibility for terminating its voluntary commitment.

Q. How does PGE respond to Staff's proposed modification of Condition 6?

A. In its testimony, Staff proposed the following modification:

> Voluntary renewable energy product offering terms and conditions must fairly account for differences from Direct Access programs. The Utility may propose terms and conditions that differ from current Direct Access provisions, but must provide evidentiary support for those differences and must consider changes to their direct access programs to match VRET terms and conditions, as appropriate.[24]

PGE appreciates Staff's emphasis on fairness rather than mirroring because "fairness" implies flexibility for consideration of the broader context. But again, as with the original condition, the discretionary nature of selecting which terms and conditions must be evaluated under the guideline leaves uncertainty. Deciding what would qualify as sufficient evidentiary support is also subjective. PGE is concerned that this revised guideline has the appearance of giving the utility opportunity for innovation, but the practical reality is it will create lengthy regulatory hurdles that will stifle opportunity for "innovation that could help transform our electricity sector, drive down greenhouse gas emissions, and meet customer demands."[25]

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[24] Staff/300 Gibbens/20: 3-8
[25] RNW/300 O'Brien/12

Q. If the Commission shares Staff's inclination to modify rather than remove Condition 6, does PGE have a counterproposal?

A. Yes. Although PGE adheres to its position that different terms and conditions apply to green tariff and Direct Access programs, PGE believes a compromise with Parties would be for the Guideline to apply to utility green tariffs that are not cost-of-service programs, rather than applying the Guideline to programs like the GEAR that are cost-of-service riders. With this in mind, PGE's revision of Staff's proposal is:

> If a utility seeks to offer a voluntary renewable energy product outside of or in lieu of cost-of-service, the following guideline applies:
>
>> Such VRET terms and conditions must fairly account for differences from Direct Access programs. The Utility may propose terms and conditions that differ from current Direct Access provisions, but must provide evidentiary support for those differences and must consider changes to their direct access programs to match such VRET terms and conditions, as appropriate.

F. Condition 7 (Utility Ownership of Green Tariff Resource)

Q. What were Parties' responses to PGE's proposal to modify Condition 7 in its updated Guidelines?

A. Condition 7 states:

> The regulated utility may own a voluntary renewable energy resource, but may not include any voluntary renewable energy resource in its general rate base. It may recover a return on and return of its investment in the voluntary renewable energy resource from the subscriber; however, the utility must share some of the return on with the other utility customers for ratepayer-funded assets used to assist the voluntary renewable offering.

PGE's proposed modifying this condition to:

> The regulated utility may own a voluntary renewable energy resource, and when it does, it must continue to ensure there is no cost shifting to non-participants.

Staff and PacifiCorp support PGE's modification. CUB agrees with PGE that the latter portion declaring the "utility must share some of its return on …" portion is not needed in the context when a green tariff is a cost-of-service rider, and therefore the subscriber is already contributing to ratepayer-funded assets.

Staff finds that PGE's modified version condenses the guideline to the core goal, that is, "a more general 'no cost shifting' rule which better applies to all potential utility owned proposals."[26]

Irrespective of PGE's modification of the condition, some Parties expressed reservations about utility ownership of a green tariff resource. RNW conditionally supports utility ownership, advocating that the Competitive Bidding Rules must apply when utility ownership is considered. CUB states that utility ownership is "reasonable … if it is not included in rate base and non-participating customers are not charged for the depreciation of the capital investment or the return on investment," and CUB expressed some concern about risk shifting to non-participants.[27] NIPPC opposes consideration of utility ownership entirely.

Q. How could a resource be in rate base and still ensure no cost-shifting to non-participants?

A. Green tariffs can be, and need to be, designed to uphold the no cost shifting mandate regardless of whether a resource is contracted through a PPA, utility-owned outside of rate base, or utility-owned in rate base.

Using PGE's Green Tariff subscription model as an example, we can explain how the directional flow of dollars changes depending on resource ownership but the net effect for non-participants is the same. With a third-party resource contracted through a PPA, subscribers are reimbursed by COS customers for the incremental energy and capacity value the resource brings

[26] Staff/300 Gibbens/20:17-18
[27] CUB/200, Jenks/15-16

to the system (via credits in the subscriber fee). Meanwhile, with a utility-owned resource in rate base, subscribers would instead reimburse COS customers for all costs less the incremental energy and capacity value the resource brings to the system.

Q. Why is PGE proposing to modify this condition, considering it has no current plans to seek ownership?

A. PGE is interested in pursuing ownership of resource for a future offering of its Green Tariff, as discussed in Section IV Subsection A, Utility Ownership of GEAR Resource, and PGE believes rate base ownership should be an available option.

Q. Is PGE proposing to further modify its proposal for this Guideline?

A. No. PGE maintains its original recommendation for this Guideline. The Guideline should uphold the allowance for utility ownership of a green tariff resource, providing the utility ensures no cost shifting, without eliminating the ability of a green tariff resource to be in rate base.

G. Condition 8 (Ensuring No Cost Shifting)

Q. PGE proposed modifying Condition 8 in its proposed updated Guidelines. What were Parties' responses to that proposal?

A. Condition 8 states:

> All direct and indirect costs and risks are borne by the participating voluntary renewable energy customers, shareholders of the utility or third-party developers and suppliers with provisions allowing independent review and verification by Commission Staff of all utility costs. Costs include but are not limited to ancillary services and stranded costs of the existing cost of service rate-based system.

PGE's proposed Guideline 6, modifying this condition, states:

> All direct and indirect costs and risks are borne by the participating voluntary renewable energy customers, shareholders of the utility or third-party developers and suppliers with provisions allowing independent review and verification by Commission Staff of all utility costs.

CUB, Renewable Northwest, and PacifiCorp support PGE's modification. Staff and NIPPC object.

PGE's opening testimony noted that it proposed the modification because customers pay for ancillary costs and existing assets by continuing on cost of service. Staff's testimony points out that "future program offerings or other VRET proposals from other utilities may be structured differently, and may not require continued service on a COS schedule."[28]

Q. Why does PGE recommend streamlining this guideline?

A. PGE continues to recommend its streamlined modification of the condition because the current second sentence is redundant of the first. The phrase "all direct and indirect costs and risks" on its own encompasses the full requirement established by House Bill (HB) 4126, which states "All costs and benefits associated with a voluntary renewable energy tariff shall be borne by the nonresidential customer receiving service under the voluntary renewable energy tariff."[29]

Q. Could stranded costs result from a green tariff program?

A. No. Stranded costs of the existing system would not result from an appropriately designed and limited green tariff program. For example, with PGE's Green Tariff we note several protections against "over-procurement": The program has a cap; customers are disincentivized from subscribing as resources become less valuable to PGE's system (via the energy and capacity credits within the subscriber fee); the energy and capacity needs that Green Tariff resources fill are currently analyzed in IRP modeling, either as contracted resources or as sensitivity cases up to the full program cap; and PGE's Green Tariff participants remain COS customers, contributing fairly to all system costs.

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[28] Staff/300 Gibbens/20-21
[29] Oregon House Bill 4126, February 11, 2014, Page 2; https://olis.leg.state.or.us/liz/2014R1/Downloads/MeasureDocument/HB4126 .

H. Condition 9 (Commission Review)

Q. PGE proposed maintaining Condition 9 with no revisions in its proposed updated Guidelines. What were Parties' responses to that proposal and has PGE's recommendation changed?

A. Condition 9 states:

> All voluntary renewable offerings must be made publicly available and subject to review by the Commission to ensure they are fair, just, and reasonable.

No Parties opposed PGE's proposal to maintain Condition 9, and PGE continues to recommend the condition's unedited inclusion in the revised Guidelines.

I. Summary of PGE's Proposed Guidelines

Q. Please summarize PGE's proposed Guidelines to replace the Nine Conditions.[30]

A. The complete list of proposed Guidelines is:

1. Renewable Portfolio Standard (RPS) definitions of resource type, location, and bundled Renewable Energy Certificates (RECs) must apply to VRET products.
2. Voluntary renewable energy options only include bundled REC products. Any RECs associated with serving participants must be retired by or on behalf of participants.
3. The year that a voluntary renewable energy program eligible resource became operational should be no earlier than one year prior to program enrollment.
4. The voluntary renewable energy program size is limited to 500 MW for PGE.
5. The regulated utility may own a voluntary renewable energy resource, and when it does, it must continue to ensure there is no cost shifting to non-participants.

[30] This list does not include PGE's counterproposal to Staff's modification of original Condition 6 because PGE's primary recommendation is to remove that condition.

6. All direct and indirect costs and risks are borne by the participating voluntary renewable energy customers, shareholders of the utility or third-party developers and suppliers with provisions allowing independent review and verification by Commission Staff of all utility costs.

7. All voluntary renewable offerings must be made publicly available and subject to review by the Commission to ensure they are fair, just, and reasonable.

IV. GEAR Program Design

A. Utility Ownership of GEAR Resource

Q. Why is PGE asking the Commission for clarity with respect to its allowing a utility-owned resource in a future tranche of its Green Tariff program?

A. Even without modification, Condition 7 allows utility ownership, and PGE may make plans for a utility-owned resource option in the future. Nevertheless, Staff writes that its support of PGE's modification of Condition 7 "does not equate to a recommendation to allow the Company to pursue utility ownership without further Commission decision"[31] and also calls a Commission decision on a utility ownership option for a future offering "unnecessary and premature."[32] PGE disagrees with Staff's assessment that it is not the right time for discussion and parameter setting of a utility-owned option. PGE agrees with the Commission's assessment that a utility could own the resource utilized for a green tariff.[33] This docket provides the appropriate venue to provide some clarification of the Commission's assessment so that if PGE were to seek Commission

[31] Staff/300, Gibbens/20: 14-15
[32] Staff/300, Gibbens/10: 9
[33] "[Conditions 6 and 7] allow for utility ownership…", Order No. 16-251 Page 3

approval for a green tariff based on an owned resource, the regulatory considerations would not be in question.

Q With a PGE-owned resource, how would PGE ensure that all costs and benefits of the Green Tariff are borne by subscribers, as required by HB 4126[34]?

A. Regardless of whether the Green Tariff program is using a third-party PPA or a utility-owned resource to supply renewable power, the fundamental characteristics of the program design and subscription fee need not change to continue to uphold the principle of no cost shifting. The three key components of the subscriber fee, a PPA or resource fee, an administration fee, and a risk adjustment fee, will continue to be charged as a rider to cost-of-service rates, and these components function the same in a third-party PPA or utility-owned resource to isolate green tariff costs from non-participants.

All costs will be allocated to subscribers, and the benefits that the Green Tariff resource provides to all cost of service customers will be allocated to subscribers through energy and capacity credits that reduce their resource fee.

Q. Please provide examples of ownership structures that can be designed to uphold the requirement of ensuring no cost shifting.

A. Without being exhaustive, some examples of how a utility could own a green tariff resource include the following:

- The utility owns the resource, and it is included in general rate base with subscribers reimbursing all customers for the premium above the energy and capacity the resource provides.

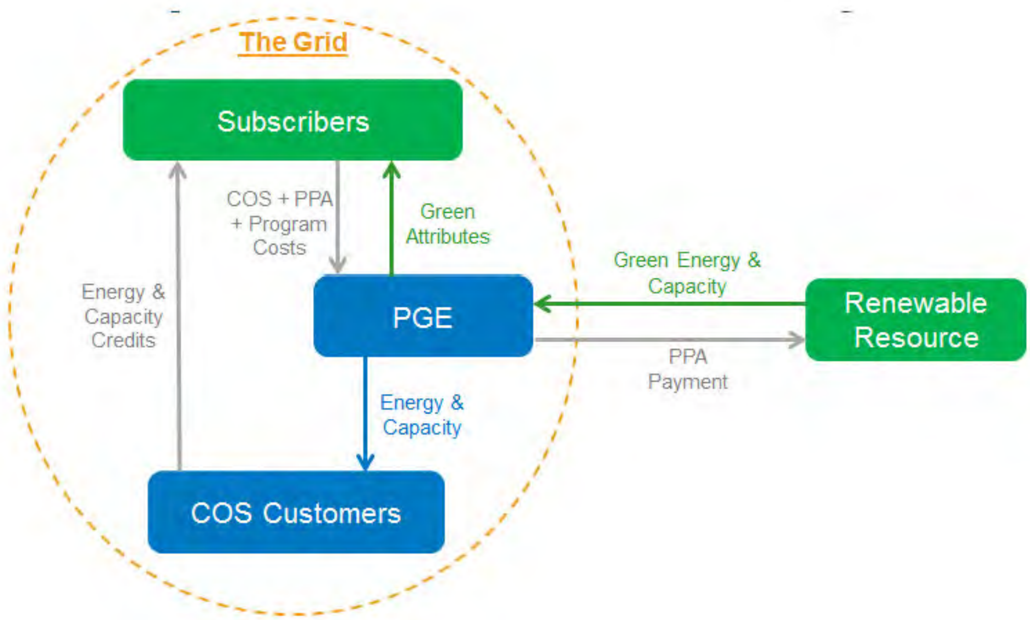
[34] Oregon House Bill 4126, February 11, 2014, Page 2; https://olis.leg.state.or.us/liz/2014R1/Downloads/MeasureDocument/HB4126 .

- The utility owns the resource and maintains it outside of rate base as non-utility business. The resource has a revenue requirement applicable only to subscribers, with subscribers paying for all costs, and the associated return on investment, less the credits over the economic life of the resource.
- A non-utility affiliate option, where the affiliate owns the resource and contracts with the utility, for the energy, capacity, and renewable attributes.

Other utility green tariff programs around the country have had utility-owned green tariff resources using different combinations of the concepts discussed above.

Q. Do these structures allow PGE to own and operate a resource without cost shifting to non-participants?

A. Yes. The full cost of ownership including operations and maintenance will be included in the resource pricing portion of the subscriber fee. The pricing will behave the same as if the resource was owned by a third-party. What changes, depending on the ownership structure, is where the exchange of program and resource costs with energy, capacity and credits occurs. The figure below, originally presented in PGE Exhibit 200, shows how the subscription design works, and this design will apply in all cases.



Q. Would the Commission have opportunity through established regulatory processes for a prudency review when PGE seeks utility ownership?

A. Yes. Established regulatory processes would require the Commission to conduct a prudence review of any PGE-owned GEAR resource, regardless of how the resource is owned by PGE. For example, if the resource is in rate base, the Commission has oversight through General Rate Cases (GRCs). If the resource is owned by a PGE affiliate, then the additional requirements and procedures of ORS 757.015, ORS 757.495, OAR 860-027-0040, OAR 860-027-0041 would apply. In both of these cases, or where the resource is owned as non-utility plant, applicable expenses will flow through power costs, where the Commission has oversight through GRCs, Annual Update Tariffs, and PGE's Power Cost Adjustment Mechanism.

Q. How would these ownership structures account for operations and maintenance expense, for example?

A. With a utility-owned rate base resource, subscribers would reimburse cost-of-service customers for all costs associated with owning the resource including operations and maintenance (in addition to the return on investment). Ownership outside of rate base would mean that costs like operations and maintenance would be priced into the resource PPA charged to subscribers.

Q. Which ownership structure would PGE seek to implement?

A. PGE has not decided on a model for ownership that it would seek to implement at a future date. The industry is constantly changing, and the ownership model that makes the most sense for PGE and its customers, both non-subscribers and subscriber, will depend on the context at the time it seeks to pursue utility ownership.

Q. Why is PGE asking for an exception of OAR Chapter 860, Division 89 Competitive Bidding Rules (CBR), even if proposing a utility-owned resource?

A. PGE has noted[35,36] the advantages of a streamlined competitive bidding process for this type of voluntary product while maintaining the least-cost, least-risk standard. The CBR could introduce a significant cost and time burden that functions as a barrier to participation and restrict PGE's agility in offering new customer- and decarbonization-focused programs. The ultimate test of pricing for a voluntary product is customer participation. Non-participants are shielded from price sensitivity by the program design having subscribers pay the premium above the energy and capacity the resource provides. Additionally, the Competitive Bidding Rules only apply to resources larger than 80 MW of nameplate capacity.[37] We continue to discuss this topic in Section V of our testimony, Resource Procurement and Long-Term Planning.

[35] PGE/500 Sims – Tinker/30-31
[36] PGE Request for Waiver of OAR 860-089-0010 dated March 29, 2019
[37] OAR 860-089-0100(c)

B. Risk Adjustment Fee

Q. What were Parties' responses to PGE's identification of an expanded list of risks that the risk adjustment fee should compensate for?

A. Staff and RNW each state in their opening testimony a need for more details about PGE's identified expanded risks. Staff writes, "Although Staff has no issue with compensating shareholders or potentially COS customers for appropriate risks, the PPA risk and lack of clarity on how risk adjustment is calculated, in light of the additional risks identified by PGE, are of concern to Staff."[38]

Q. Please clarify PGE's intentions with the expanded risk adjustment fee.

A. Green tariffs introduce additional risks that must be addressed in order to develop a sustainable program. PGE aims to fully insulate cost-of-service customers from, and also fairly compensate shareholders for, the risks associated with this voluntary program. This ensures a program that is based on the foundational concept of no cost-shifting.

In its Phase II Opening Testimony, PGE has described some risks for which the risk adjustment fee should compensate. These risks include, but are not limited to, risks associated with under-subscription, customer load variability, variable resource, and resource PPA.

Q. Please describe the proposed risk adjustment fee calculation.

A. PGE recommends a range, as a portion of the PPA price, be applicable for the risk adjustment fee. PGE does not propose prescriptive analytical methodologies for each risk because each resource and contract will be different, making a comprehensive formulaic approach that applies broadly challenging.

[38] Staff/300 Gibbens/13: 7-11

In Phase I testimony, PGE estimated a range of 1 to 5 percent of the PPA price for the risk adjustment based on the under-subscription risk. PGE is willing to consider a cap on the expanded risk adjustment in order to give stakeholders a sense of possible magnitude; therefore, PGE proposes the adjustment be no more than 10% for comprehensive program- and PPA-based risks.

Because the Green Tariff is a voluntary program, any concern that this risk adjustment gets too large would be constrained by subscriber willingness to pay. Conversely, the flexibility within the risk adjustment fee range would prevent the risk adjustment fee from being too small to adequately compensate shareholders for project- and tranche-specific risks.

Q. As Staff asks, could the customer load variability and variable resource risk "lead to the use of other COS resources to correct these issues?"[39]

A. No. The risks that load variability and variable resource risk introduce because of the commitments made to Green Tariff subscribers are born by PGE shareholders and other COS resources will not be used to mitigate this risk. These risks are constrained to the value of any theoretical REC shortfall or oversupply which PGE sees as manifesting in the following possible situations:

- Subscriber load increases: Customers subscribe to an annual maximum amount. If load increases above this amount, PGE has no obligation to secure additional RECs for the subscriber.
- Subscriber load decreases: In the event that a subscriber's load is reduced by 20% or more, PGE may reduce the subscription amount for the subsequent years and re-market the additional product to secure incremental subscriptions. Regardless of the outcome of that

[39] Staff/300 Gibbens/14: 17-19

effort, cost-of-service customers continue to receive the energy and capacity from the resource.

- Resource under-generation: The subscriber agreement between PGE and the customer commits PGE to delivering bundled RECs for a predetermined amount of subscriber load. PGE has included performance guarantees in the PPA to significantly reduce the risk that material under-generation occurs. Any under-generation risk not addressed by these performance guarantees requiring the purchase of RECs to fulfill the subscriber agreement would be a PGE shareholder risk.
- Resource over-generation: Any RECs the resource generates above subscriber commitments may be sold or banked to help mitigate the risk of future under-generation.

Beyond REC risk, all customers are paying for the energy the resource provides. This energy is treated the same as all contracted variable resources in the AUT. Resource production variability is subject to the PCAM, which is the regulatory mechanism chosen to address this risk.

While each of the above situations may manifest differently, cost-of-service customers are insulated from cost-shifting. Additionally, subscribers remain cost-of-service customers and continue to pay all approved costs associated with operating the electric system.

Q. Staff notes that it is inconsistent that no PPA risk adjustment is applied to account for risk in cost-of-service PPAs. Does PGE agree?

A. Yes. PGE recommends exploring a risk adjustment for cost-of-service PPAs in another docket.

Q. Is the PPA risk "effectively a return on investment for shareholders," as Staff states?

A. Yes. It attempts to compensate shareholders for the additional risk created by PPAs.

C. CSO Size Eligibility

Q. What have Parties' responses been to PGE's 10 MWa size requirement for the Customer Supply Option?

A. RNW supports PGE's 10 MWa requirement and proposes that it may evolve with experience resulting in a lower size threshold. Walmart disagrees with PGE's requirement, advocating instead for a 5 MWa threshold. NIPPC also disagrees with the 10 MWa size requirement. Staff advocates for case-by-case determination.

Q. What would the impact of a lower size requirement be to subscriber cost?

A. A lower size requirement likely increases administrative costs, which could result in a higher subscriber fee, and will make it more difficult to source resources (which will necessarily be smaller sized). Although a lower size requirement may attract more customers, it will result in PGE ultimately reviewing and negotiating many more contracts' terms and conditions to ensure suitability for PGE's system and customer protections.

Also, as discussed in PGE's response to OPUC Data Request No. 022, which is provided as Exhibit 602, the lower size threshold would likely raise resource costs. With smaller projects for smaller customer loads, neither PGE nor the developer would be able to take advantage of the economies of scale that occur with a larger project.

PGE can more economically and efficiently serve smaller customers by aggregating their demand under the PGE Supply Option.

Q. What is PGE's response to Parties' suggestions for reducing the size requirement to 5 MWa or allowing case-by-case consideration?

A. PGE does not support Walmart's suggestion of moving from 10 MWa to 5 MWa, but PGE finds Staff's suggestion to allow customers to petition the Commission for individual waivers to be reasonable. This case-by-case consideration may be a compromise offering flexibility for customers who may have smaller presence in PGE's service area but still have experience, ability, opportunity and specific interest in finding their own PPA.

D. Credits, Net Bill Savings

Q. Please describe Parties' feedback on PGE's energy and capacity credit calculation methodology, including fixed credits and not allowing for a net bill savings.

A. Parties' feedback has been tentatively supportive of the Commission-approved methodology with some continuing interest in a floating credit option with possibility for net bill savings.

Staff supports the approved methodology's use of fixed rather than floating credits as well as this methodology's limitation on the credits such that they disallow net bill savings. Nevertheless, Staff expresses reservations about the forward-looking nature of the credit calculation methodology.

RNW supports PGE's and the Commission's case-by-case consideration of floating credits for CSO subscribers. Ultimately, RNW prefers a floating credit approach that would allow subscribers the opportunity for net bill savings, stating this may encourage more participation in the program and therefore more renewable development.

CUB is concerned about the forward-looking nature of the Commission-approved methodology for energy credits and proposes an alternate, annually-updated energy credit calculation methodology using PGE's MONET power cost model. CUB supports PGE's capacity credit methodology with a modification to use a technology-neutral, least-cost capacity value instead of defaulting to the single cycle combustion turbine capacity value. With its floating credit proposal, CUB considers allowing subscribers the possibility of net bill savings yet also notes that situation is unlikely to occur frequently.

Walmart advocates for floating credits anchored in marginal cost of service, which had been AWEC's preferred methodology in Phase I of this docket.

Q. Please respond to CUB's position that cost-of-service customers should prefer a floating credit methodology over a fixed credit methodology.

A. Cost-of-service customers should be neutral to a fixed or floating credit methodology. Under the fixed credit methodology, cost-of-service customers have price certainty yet take forward price risk by anchoring the credits with the IRP methodology at the beginning of the program. In other words, if actual energy prices are higher than the IRP methodology-produced credits, cost-of-service customers will receive the benefit. If actual energy prices are lower, cost-of-service customers will be exposed to the market price impacts.

As CUB's testimony acknowledges, this is the normal risk cost-of-service customers take in all resource acquisitions and is not introducing any new risk. Under a floating credit methodology, cost-of-service customers reduce their reliance on forecasts but also gain price uncertainty. However, cost-of-service customers will still be exposed to the risk of these annual price forecasts, assuming CUB's methodology, diverging from actual market prices. This risk exists in both the floating and fixed credit approach and is a result of the Commission-approved forward-looking power cost forecasting process.

Although CUB acknowledges the forward price risk is normal-course-of-business, CUB argues that cost-of-service customers should not be subject to this risk for the Green Tariff because its resource procurement occurs outside the IRP and has "not been found to be the least cost/least risk way to meet customers' resource needs"[40] and are "not being built to respond to a need for new resources to serve load identified in the IRP."[41] PGE disagrees with CUB's assessment on two points: 1) the Green Tariff credits are based on identified needs, both energy and capacity, and through the credit calculation the resource does respond to an IRP need and 2) Green Tariff resources will be acquired through a competitive bidding process to select the least-cost, least-risk project recognizing their contribution to both energy and capacity.

Q. Please respond to Walmart's concern that the Commission's case-by-case consideration of floating credits and net bill savings for CSO customers creates uncertainty that is "a significant barrier to action by customers."[42]

A. Floating credits, by their changing nature, are uncertain, and customers desiring price certainty should prefer the fixed credits of the approved methodology. Walmart's concern that a "customer would attempt to evaluate the benefits and costs of a renewable project without any insight into what the credit might be"[43] is not alleviated by removing the Commission's case-by-case consideration of the floating credit methodology. Furthermore, as PGE discusses in OPUC Data Request No. 053, provided as Exhibit 603, PGE would support a subscriber interested in filing a waiver with the Commission, so customers should not experience "a significant layer of regulatory risk and litigation cost to a potential project."[44]

[40] CUB/200 Jenks/6: 12
[41] CUB/200 Jenks/6: 10
[42] Walmart/300 Chriss/3-4
[43] Walmart/300 Chriss/3: 21-23
[44] Walmart/300 Chriss/3: 23-25

Q. What have Parties' reactions been to PGE's approach to using the IRP methodology to calculate energy and capacity credits to subscribers?

A. RNW notes that it is not satisfied with how the Green Tariff capacity credit calculation methodology is limited to considering contribution to years of insufficiency. In addition, RNW would like the Commission to revisit that topic within the Green Tariff after the capacity credit methodologies are addressed in the General Capacity Investigation in UM 2011.

CUB proposes alternate crediting methodologies that also float over time, removing reliance on forward price projections. We discuss CUB's proposals above. In thinking about the expansion of the Green Tariff, Staff writes that the credit methodology "is flawed in some sense."[45]

Q. Please respond to Staff's statement that the credit methodology "is flawed in some sense."

A. Staff writes

> There are two potential concerns [with the crediting methodology]. The first is that the crediting methodology is flawed in some sense. The IRP ultimately estimates what resource costs will be, where as an RFP better indicates market prices for those resources. The second is that an IRP occurs every two years, whereas the VRET resources are 20 year commitments. As the prices for a particular technology change, the IRP will adapt to them, but a VRET based resource will remain fixed.

Staff's first point is unclear as the energy credit calculations uses neither IRP estimates of resource costs nor Request for Proposal (RFP) market prices. While the capacity credit calculation does rely on the estimated cost of a proxy capacity resource, these estimates are provided by a third-party consultant and are widely accepted in various regulatory proceedings.

[45] Staff/300 Gibbens/25: 22

Staff is correct in its second point that the Green Tariff, like all other procurement actions, requires making commitments based on the best information that is known and knowable at the time. The future is always uncertain, and that fact cannot preclude long-term planning or, in the case of the Green Tariff, prevent action being taken to meet customers' stated need for the product and to address the climate crisis. Prudency means using reasonable judgment in light of the facts known at the time. PGE also notes the IRP update cycle is typically closer to one year and that green tariff resource commitments may be less than 20-year commitments (e.g., the first offering of the Green Tariff has 15-year customer agreements and a 15-year PPA).

Q. Does PGE recommend any changes to its current fixed energy and capacity credit methodology that prevents net bill savings?

A. No. PGE continues to advocate its approach to the energy and capacity credits. The Commission-approved methodology offers pricing safeguards to non-participants, who by the fixed credits are not exposed to market risk, and the credits function as a feedback mechanism from the IRP methodology about the need for the resource. Despite some Parties' concern about the lack of floating credit mechanism providing opportunity for subscribers to gain net bill savings, PGE has not heard this concern from subscribers themselves. In fact, PGE has observed considerable customer demand in this fixed price premium product.

V. Resource Procurement and Long-Term Planning

A. Bilateral PPA for CSO

Q. Should a PPA contracted for the CSO be bilateral between PGE and the independent power producer?

A. Yes. We understand there are concerns about this bilateral contracting being brought to the Commission at the public meeting on October 22, 2019, and PGE expects this topic to be addressed in that forum. PGE's position is that a green tariff is most effective when a utility acts as the intermediary delivering supply to the end-use customer. As we explained in the first phase of this docket, a contract that does not involve the utility essentially functions to provide the customer with complete discretion to negotiate terms to their benefit without considering the costs to remaining customers.

Additionally, while we are not attorneys and the Company will present its legal analysis in briefing, there is concern that contracts directly involving the end-user and the supplier may not be allowed under Oregon law for cost-of-service customers. PGE also discusses that concern in its response to OPUC Data Request No. 051, provided as Exhibit 604.

Ultimately, PGE is the party receiving the energy and capacity from the resource and making payments to the resource owner. The contract approach should be bilateral between PGE and the owner as that aligns with contract obligations and responsibilities while providing adequate protections equally for cost-of-service customers.

B. Applicability of Competitive Bidding Rules

Q. What have Parties' responses been to PGE's request for a waiver of the Competitive Bidding Rules (CBR) for procurement of GEAR resources?

A. Staff supports a waiver up to the approved cap of the GEAR rather than a blanket waiver that would apply to any future expansion of the GEAR. RNW acknowledges a "streamlined competitive bidding process may be appropriate"[46] unless the utility is seeking ownership of a resource, and in that case RNW advocates the CBR be applied. NIPPC opposes PGE's request for a waiver.

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[46] RNW/300 O'Brien/14

Q. Please respond to Staff's proposal of a limited waiver of the CBR, for procurement within the approved cap of the program?

A. Staff's proposal is reasonable, allowing the Commission the ability to make incremental evaluations of the CBR applicability as the GEAR expands.

Q. Does the CBR apply to procurement of resources less than 80 MW, regardless of whether the solicitation is limited to third-party PPAs or is inclusive of a PGE-owned resource?

A. No. OAR 860-089-0100 states that the CBR apply for resources or contracts for more than an aggregate of 80 MW and five years in length or as "directed by the Commission."[47] Notwithstanding the CBR, resources on this scale would be unduly impacted by the increase in costs resulting from designing a new RFP, retaining an independent evaluator, and following the standard evaluation process.

Q. Without the CBR, how would PGE demonstrate its ownership option is the best option for subscribers?

A. PGE expects to follow the process outlined in PGE's response to OPUC Data Request No. 040, provided as Exhibit 605. PGE can also leverage other procurement actions, such as that of any future renewable RFPs, to evaluate available resources without having to independently conduct the full Independent Evaluator process again for this voluntary program. In doing so, PGE will ensure a fair and transparent process whereby the Company makes resource criteria available ahead of time, solicits and accepts bids from all interested Parties, uses Commission approved evaluations methodologies, and provides the opportunity for Staff and the Commission to provide review and oversight of the entire process.

[47] OAR 860-089-0100(d)

C. "Built for GEAR" Requirement

Q. In PGE's GEAR, PGE has required that eligible resources be "built for the GEAR." What have been Parties' responses?

A. Parties have expressed concern about PGE's "built for the GEAR" requirement, and PGE understands much of it is due to the ambiguity of the term, and how PGE would interpret it.

Q. What does "built for the GEAR" mean?

A. PGE defines a resource "built for the GEAR" as a resource that achieves commercial operation after the execution of a contract for the project's energy.

Q. Why is PGE's requirement for the GEAR more stringent than what the conditions or Guidelines require?

A. Requiring resources to be built or expanded specifically for customers is the purest implementation of additionality, and the level of additionality that PGE's customers want.

Nevertheless, PGE recommends the updated Guidelines be defined more broadly in order to allow some flexibility for future green tariff product development over time.

D. Transmission

Q. What have Parties' reactions been to PGE's discussion of its transmission requirements for future offerings of its GEAR?

A. Staff and RNW state that they support PGE's consideration of relaxed transmission requirements. Staff further finds as "reasonable and fair"[48] the Company's approach to addressing the transmission issue in a holistic way in the IRP forum and its plan to keep Green Tariff resource transmission requirements consistent with those of any future RFP. NIPPC's testimony reaffirms NIPPC's opposition to the previous requirement for firm transmission.

[48] Scott/300 Gibbens/24: 14-15

Q. Since PGE's opening testimony, PGE submitted its 2019 IRP Addendum on August 30, 2019 proposing an interim transmission solution. Is PGE proposing to apply that interim solution to Green Tariff procurement?

A. Yes. PGE's 2019 IRP Addendum specifically stated that the interim transmission solution would be "[a]pplicable only to newly procured variable renewable resource pursuant to an IRP Action Plan or in support of voluntary renewable programs."[49] The 2019 IRP Addendum is provided in Exhibit 606 for reference.

E. IRP Interactions

Q. What have Parties' reactions been to PGE's approach to including Green Tariff interactions within its IRP?

A. PGE's opening testimony discussed the sensitivity analyses conducted in the then-draft 2019 IRP with yet-to-be-contracted resources including the Green Tariff. In future IRPs, contracted Green Tariff resources will be included in the reference case, and any capacity available in the program will be continued to be modeled within sensitivity cases.

Staff supports PGE's approach with the sensitivity analyses and states, "being cognizant of the potential increases to the resource portfolio outside of the IRP should result in an IRP process which achieves the best outcome for COS customers."[50] RNW also agrees that PGE's sensitivity analysis approach is "appropriate."

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[49] *See* 2019 IRP Addendum, Page 4
[50] Staff/300 Gibbens/25: 5-8

Q. What is PGE's response to Staff's suggestion to do a "with and without GEAR" scenario in the IRP?

A. PGE agrees with Staff's suggestion with respect to the need assessment. This "with and without GEAR" modeling is what PGE has done in comparing the reference case and sensitivity case model runs in the 2019 IRP, to understand how potential, not-yet-contracted resources will impact the system need. However, PGE clarifies that "with and without GEAR" modeling in the IRP, including in portfolio analysis, is not a test that could be used, as Staff proposes, "to ensure that COS customers are not the subject of unwarranted cost shifting or other impacts."[51] In other words, IRP portfolio analysis does not directly correlate to a change in COS customer costs.

Q. Should stakeholders be concerned about the Green Tariff having an unlimited potential to impact long-term resource planning?

A. No. The Green Tariff program is capped; PGE recognizes it cannot and would not grow indefinitely. PGE seeks a limited increase to the cap now and will return to the Commission whenever it seeks future increases to the cap, providing opportunity for the Commission to evaluate at each interval the level of impact to long-term resource planning. The Green Tariff need not be a static program, and PGE anticipates subsequent offerings will evolve as IRP modeling evolves over time and in response to different legislative actions, for example, with new potential legislative carbon reduction initiatives like cap and trade. PGE views the Green Tariff as a path for customers to accelerate their adoption of carbon free power, and as PGE's system becomes increasingly decarbonized, this path may no longer be needed. PGE does not view the Green Tariff as a replacement for the IRP for long-term planning and procurement.

[51] Staff/300 Gibbens/26: 11-14

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	**Description**
601	PGE's Press Release Dated August 21, 2019
602	PGE's Response to OPUC Data Request No. 022
603	PGE's Response to OPUC Data Request No. 053
604	PGE's Response to OPUC Data Request No. 051
605	PGE's Response to OPUC Data Request No. 040
606	PGE's 2019 Integrated Resource Plan Addendum

Sustainability Leaders Claim PGE's Green Future Impact in Record Time

Newest offering helps leaders in digital, education, healthcare and public sectors support new renewable energy facility in Oregon

Aug. 21, 2019

PORTLAND, Ore. — Portland General Electric (NYSE: POR) recently launched Green Future Impact, a new solution that helps large commercial and industrial customers source 100% of their electricity from new wind or solar renewable energy facilities. After enrollment opened, customers committed to purchase output equal to an approximately 160-megawatt renewable energy facility in just over three minutes.

Green Future Impact gives customers another way to meet aggressive sustainability and climate goals. Customers who enrolled in the program include Adobe, Comcast, Daimler Trucks North America, Digital Realty, Oregon Health & Science University, Portland Community College, Portland State University and the cities of Beaverton, Hillsboro, Lake Oswego, Milwaukie, Portland, Salem, West Linn and Wilsonville, along with Multnomah and Washington counties.

"Cities and large customers are leading the way to a clean energy future. We are pleased to offer another cost-effective way to help them achieve their green energy goals," said PGE President and CEO Maria Pope. "Together, we are making Oregon an example in the fight against climate change."

Subscribers to Green Future Impact help accelerate a cleaner energy supply in our region. Their subscriptions to a dedicated power purchase agreement will bring a new wind or solar facility online. The first facility will be located in Oregon and operational by the end of 2021. As a bundled green product, customers will receive energy from that facility, along with the associated renewable energy credits.

Approved by the Oregon Public Utility Commission earlier this year after a collaborative process, customers qualify if they have more than a 30-kilowatt annual aggregate peak demand or a 10-megawatt average load. Green Future Impact may add up to 300 megawatts of new renewable resources to PGE's system.

Subscriptions are for 10- or 15-year terms, and pricing reflects the actual cost of producing and delivering the energy from a specific facility. The product is self-supporting, ensuring that no costs are shifted to non-participating customers. For more information, go to www.PortlandGeneral.com/greenfutureimpact.

Quotes from Green Future Impact's business and municipal customers:

"Adobe is proud to partner with PGE on their Green Future Impact—the very first green tariff for PGE. This is an important step toward PGE's renewable energy deployment and will be instrumental in helping Adobe meet our RE100 goal and Science-Based Targets by decarbonizing the grid that powers the majority of our digital operations. We are fully supportive of bringing renewable energy not only to our facilities but also to our communities, so that both people and businesses can thrive in the long run," said Vince Digneo, sustainability strategist, Adobe.

"We are excited that PGE introduced a product that will help us go greener faster. By participating, the City of Beaverton will reduce our greenhouse gas emissions and save with long-term, fixed pricing. We'll also help to bring a new renewable energy facility to life, for a cleaner future," said Denny Doyle, mayor of Beaverton.

"Being part of Green Future Impact allows us to do our part in furthering the company's aspirational goal of powering all of our buildings, as well as our network and operations, with 100% renewable energy. We're proud to partner with PGE and align with the values of the local communities we serve in an effort to decarbonize the region's energy supply," said Marion Haynes, vice president of External Affairs for Comcast Cable, Oregon/SW Washington.

"Digital Realty continues to actively engage with Portland General Electric and other utility providers to identify cost-effective renewable energy solutions. We applaud PGE's efforts to develop new renewable energy solutions for its customers in Oregon, which supports our objectives to bring clean energy to our customers," said Aaron Binkley, senior director of Sustainability at Digital Realty.

“The City of Hillsboro is committed to a sustainable future. We've been actively reducing our greenhouse gas emissions for the past ten years. In that time, we've reduced emissions from city operations by 30%, and the Green Future Impact program will help us go further. It saves money, helps us meet our goals to go greener faster, and it fuels opportunity in Oregon's growing renewable energy economy,” said Steve Callaway, mayor of Hillsboro.

“The City of Milwaukie is proud to partner with PGE to power city facilities and operations with clean, renewable electricity through Green Future Impact. The city's decarbonization of its operational electricity is one of many climate actions called out in the Milwaukie Community Climate Action Plan, and a large step forward in reaching our community's climate goals of net-zero carbon emissions from electricity by 2035, and complete community-wide carbon neutrality by 2050. The success of Green Future Impact shows the regional demand for renewable electricity that minimizes our communities' contributions to the climate crisis and maximizes the shared benefits that new renewable energy infrastructure provides. PGE's hard work to lift this opportunity, as well as its commitments to decarbonizing its portfolio, has not gone unnoticed. We look forward to working with PGE to explore a more sustainable future and reaching our climate goals through innovative technologies and renewable energy programs like Green Future Impact,” said Mark Gamba, mayor of Milwaukie.

“The City of Lake Oswego is working to strengthen the state's renewable energy sector. Choosing Green Future Impact was an easy choice. We get the satisfaction of building a connection to a local renewable energy facility and competitive long-term pricing,” said Kent Studebaker, mayor of Lake Oswego.

"This project with PGE proves that technology is not the barrier for achieving our climate goals, it is a matter of having the political courage to act. With this project, we are taking the bold step of building renewable energy resources in our state and putting those resources to work for our community," said Deborah Kafoury, chair, Multnomah County Board of Commissioners.

"Portland is a leader in creating a cleaner, greener city, from our parks and our open spaces to the energy we rely on to serve our citizens. With Green Future Impact, we're closer to meeting our goal of relying 100% on renewable energy for city operations by 2030," said Ted Wheeler, mayor of Portland.

"Portland Community College has been a long-time leader of sustainable practices and environmental education, both in the classroom and in the field. We appreciate our partnership with PGE to mitigate greenhouse gas emissions, which we estimate will be reduced by 20% thanks to the Green Future Impact program — getting us that much closer to reaching our Climate Action Plan goals," said Mark Mitsui, president of Portland Community College.

"Green Future Impact will allow us to source almost a quarter of campus electricity needs from renewable energy generated right here in Oregon. We are thrilled to be one of several public entities participating. This is a significant step towards our university climate action and sustainability commitments, reducing the carbon emissions associated with campus energy use while supporting the local clean energy economy," said Stephen Percy, interim president of Portland State University.

"We are proud to partner with Portland General Electric and join their Green Future Impact program. It allows the city to cost-effectively increase our use of abundant, renewable energy to a total of over 80%. This is a win for everyone," said Chuck Bennett, mayor of Salem.

"In keeping with our sustainability goals, Washington County is committed to energy efficiency and increasing the use of renewable energy as we provide service to the community. We're grateful for the opportunity to subscribe to the PGE Green Future Impact program as a means to ensure that county operations will transition to 100% renewable power by 2040, at the lowest possible cost," said Kathryn Harrington, chair, Washington County Board of Commissioners.

"West Linn is beyond excited to be a part of PGE's cutting-edge Green Future Impact Program. Having a direct relationship with a local renewable energy source makes it easy to see where we are making a positive environmental impact, and the low rate makes it possible for the City of West Linn to reach their sustainability goal of 100% clean renewable energy use far earlier than previously imagined. We hope our City being at the forefront of sustainable energy will set an example for our community and surrounding communities to invest in our collective futures through clean energy," said Russell Axelrod, mayor of West Linn.

About Portland General Electric Company

Portland General Electric (NYSE: POR) is a fully integrated energy company based in Portland, Oregon, serving approximately 887,000 customers in 51 cities. For more than 130 years, PGE has been delivering safe, affordable and reliable energy to Oregonians. Together with its customers, PGE has the No. 1 voluntary renewable energy program in the U.S. With approximately 3,000 employees across the state, PGE is committed to helping its customers and the communities it serves build a clean energy future. For more information, visit **PortlandGeneral.com/CleanVision (/our-company/energy-strategy/oregons-clean-energy-future)**.

For more information contact Steve Corson, PGE, **503-464-8444**, **Steven.Corson@pgn.com (mailto:Steven.Corson@pgn.com)**

For more information contact: Melanie Erdrmann, PGE, **503-464-8790**, **Melanie.Erdrmann@pgn.com (mailto:Melanie.Erdrmann@pgn.com)**

July 26, 2019

TO: John Crider
Public Utility Commission of Oregon

FROM: Karla Wenzel
Manager, Pricing & Tariffs

PORTLAND GENERAL ELECTRIC
UM 1953 Phase II
PGE Response to OPUC Data Request No. 022
Dated July 11, 2019

<u>Request:</u>

PGE/500 Sims-Tinker/10: 3 states that Load size is important for economies of scale in administering the program. Please provide any analysis and a narrative explanation as to how PGE decided on the size requirement. Would a lower size threshold raise administrative costs for all customers in the program? If so, by how much? Is the relationship between number of customers in the program and administrative costs linear?

<u>Response:</u>

PGE based its size threshold on its experience developing and procuring renewable resources. 10 MWa translates to approximately 25-40 MW nameplate facility, depending on the underlying source (e.g. solar or wind). Based on PGE's experience, this is the smallest scale resource that is technically achievable while remaining competitive and having a higher likelihood of reaching commercial operation. Additionally, the majority of PGE's commercial and industrial customers have loads below 10 MWa in size, which would require a "critical mass" of customers before a resource could be developed, essentially resulting in the PGE Supply Option.

A lower threshold would likely raise both administrative and resource costs as neither PGE nor the developer would be able to take advantage of the economies of scale that occur with a larger project, such as interconnection cost, equipment pricing, etc. PGE has not undertaken analysis to directly estimate the increased costs or the exact relationship between the number of customers and costs as it would depend on several factors such as the number of customers, the number of individual resources, the sizes of the individual resources, the number of developers, all of which are not known at this time.

As detailed in PGE/500, Sims-Tinker/10, PGE wants to ensure the program remains affordable, without added risk for cost-of-service customers, and believes the right balance is achieved by limiting the Customer Supply Option to larger customers.

October 7, 2019

TO: John Crider
Public Utility Commission of Oregon

FROM: Karla Wenzel
Manager, Regulatory Strategy and Policy

PORTLAND GENERAL ELECTRIC
UM 1953 Phase II
PGE Response to OPUC Data Request No. 053
Dated September 27, 2019

Request:

Please describe from inception to completion how a customer interested in a floating credit would enroll in the GEAR under the Company's understanding of the process. Please specifically describe what ability the Customer has to negotiate the pricing structure with the PPA.

Response:

In Order No. 19-075 at page 6, the Commission granted that, for Customer Supply Option subscribers, the Commission will "entertain individual applications for arrangements with a floating credit, which do not guarantee net savings to a participant, but may result in net participant savings." A customer interested in a floating credit must meet the size eligibility requirements of the CSO and have conversations with PGE about their interest. PGE could help the customer file a waiver request with the Commission to include the floating credit methodology, which PGE would expect to be an annually recalculated implementation of the approved methodology, in line with the example PGE provided in its UM 1953 bench request submission on November 6, 2018. If the credit methodology and waiver were then approved by the Commission, PGE would implement it.

A CSO subscriber may negotiate with a developer the pricing within a PPA it "brings" to PGE to the extent the PPA meets PGE's published PPA requirements. Generally, most renewable PPAs follow the same pricing structure with the product being charged for on a dollar per MWh basis. Beyond an application for an annually floating credit, a CSO subscriber may not negotiate with PGE the pricing *structure* of the subscription fee that includes the PPA price; the subscription fee pricing structure has been established by tariff Schedule 55, which has been approved by the Commission.

October 7, 2019

TO: John Crider
Public Utility Commission of Oregon

FROM: Karla Wenzel
Manager, Regulatory Strategy and Policy

PORTLAND GENERAL ELECTRIC
UM 1953 Phase II
PGE Response to OPUC Data Request No. 051
Dated September 27, 2019

Request:

Regarding page 3, under "Negotiation of Customer Supply Option PPAs" of PGE's Compliance filing dated September 13, 2019: Please provide examples from the UM 1953 record prior to March 5, 2019 which the Company believes indicate PGE's intent and design to have the PPA contract exclude the CSO customer.

Response:

PGE has organized its response in three parts: (1) PGE's understanding of the statutory limitations on a customer entering into agreement to purchase electricity, as context for UM 1953, (2) UM 1953 Phase 1 record on PGE's subscription model for its Green Tariff, and (3) UM 1953 Phase 1 record on PGE's Customer Supply Option.

1. Statutory limitations
Although not explicitly addressed within the UM 1953 Phase I record, the legal context in which a customer could enter into a Power Purchase Agreement (PPA) is relevant to this Data Request. PGE's understanding of Oregon law is that a customer should not enter into a contract to receive electricity services from an entity other than the utility or a certified Electric Service Supplier (ESS). This understanding informed our approach to the Customer Supply Option contract.

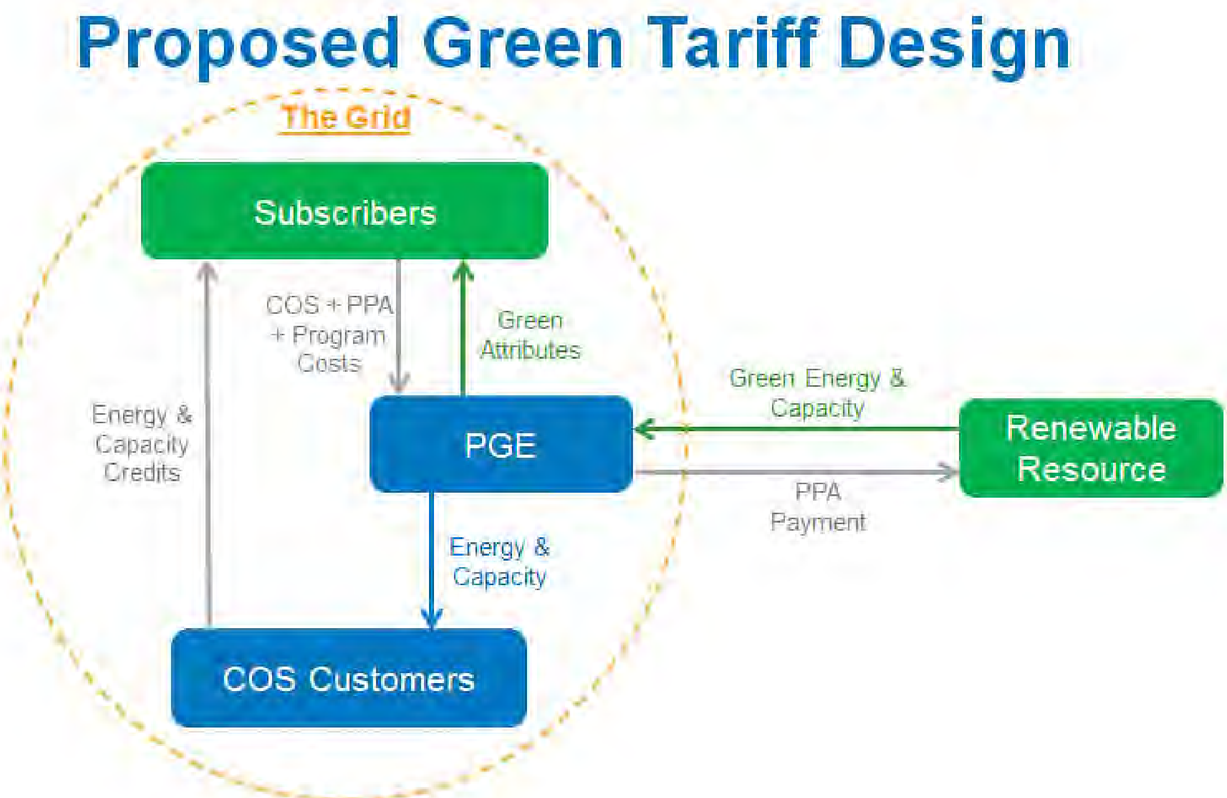
When Senate Bill 1149 restructured the electricity market in Oregon, it gave nonresidential customers the "ability to purchase electricity and ancillary services directly from an entity other than the distribution utility."[1] The only other entity authorized to sell those nonresidential customers electricity services is an ESS, certified by the Commission.[2] Under PGE's approved program design, the Green Tariff subscribing customer remains a cost-of-service customer, and thus receives electricity services from the utility and not from another entity. The statutory framework does not contemplate the

[1] Oregon Senate Bill 1149 in 1999, ORS 860-038-0005(13)
[2] ORS 860-038-0420(2)

customer receiving supply from the utility and also contracting with an ESS nor does it contemplate a customer directly contracting with a generation resource developer (who is not an ESS) for electricity service.

2. Defining the Subscription Model

In UM 1953 PGE Exhibit 200 at page 9, PGE provided a graphical representation, reproduced below, of the now-approved Green Tariff.



This design shows PGE as the recipient of the green energy and capacity, i.e. the off-taker of the PPA. In that same testimony, PGE directly stated, "PGE will enter into a PPA(s) with a renewable resource…." It also shows a distinct exchange between PGE and subscribers, of green attributes for the subscriber fee labeled as "COS + PPA + Program Costs". PGE's contracting has been consistent with this diagram: one agreement between PGE and its subscribers and a separate agreement between PGE and the resource owner.

In AWEC's opening testimony, AWEC clearly contrasts PGE's proposed subscription model with virtual PPA and market-based models.[3] AWEC supports PGE's subscription model and notes that the "virtual PPA option generally requires the execution of a special contract between the utility and its customer, which is not common practice in Oregon." AWEC's testimony requests an option for a large customer to have more involvement in the resource process within the subscription model in order to avoid large customers being "disincentivized from participating…" Importantly, AWEC envisions this large

[3] AWEC Exhibit 100 at pages 3 and 4

customer option within PGE's subscription model, and in the subscription model, as shown in the diagram above, PGE is the sole contracting entity with the resource owner.

<u>3. Introduction of Customer Supply Option</u>
Notably, PGE's initial proposal did not include the Customer Supply Option. In later testimony, PGE Exhibit 400, PGE proposed the option in response to proposed variants recommended by NIPPC and AWEC in their respective opening testimonies. NIPPC proposed a "bring your own PPA" model to "allow a given customer to tailor its PPA to its load size and start date"[4] and that is described much like the virtual PPA arrangement detailed in AWEC Exhibit 100. AWEC described an option for large customers to exercise more choice in resource procurement within PGE's subscription model.[5]

In describing a customer-sourced arrangement, AWEC clearly identified PGE as the responsible party for contracting, "The Company must review and approve any solicitation and *remains ultimately responsible for contracting with the seller* [emphasis added]".[6] This AWEC testimony advocated for customer choice and the customer's ability to participate in the contract negotiation process, yet the testimony is also clear that the contract would be bilateral between PGE and the developer.

NIPPC proposed removing the utility almost entirely from the process in its initial conception of a "bring your own PPA" model in testimony. NIPPC recommended the "Commission *require PGE to accept* [emphasis added] pre-negotiated agreements where a customer can supply their own renewable PPA entered into with a third party power provider."[7]

In response to the proposals by AWEC and NIPPC, Staff wrote in its cross-answering testimony, that "*so long as the utility maintains the ability to amend or approve a contract* [emphasis added] and the contracts comply with the policies of the program, a "bring your own PPA" approach may provide additional flexibility while continuing to avoid potential cost shifting or harm to COS customers."[8]

PGE's proposal of the "bring your own PPA" model, in its Exhibit 400, was never aligned with NIPPC's expectations but was intended to align with AWEC's proposal and Staff's recommendation. PGE emphasized its central role in holding the PPA in PGE Exhibit 400 at page 4, by identifying the need "to prevent inappropriate risk shifting from the PPA to cost-of-service customers, the proposed contract must conform to PGE's requirements and the Company retains approval rights for all terms and conditions." This PGE model is the model the Commission approved when it granted PGE ability to "review and amend all contract terms".[9]

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[4] NIPPC Exhibit 100 at pages 7 and 8
[5] AWEC Exhibit 100 at page 7
[6] AWEC Exhibit 100 at page 7
[7] NIPPC Exhibit 100 at page 7
[8] Staff Exhibit 200 at page 20
[9] Commission Order No. 19-075 at page 8

Other parties also seemed to anticipate a bilateral PPA between PGE and the developer. Walmart's cross-answering testimony recognizes the distinction between NIPPC's proposed "bring your own PPA" model and how implementation would actually work, particularly with "limitations brought about by franchise and/or other statutory provisions".[10] Although Walmart mentions a "three-way agreement", without further detail about the scope of this agreement, Walmart offers that "bring your own resource" (rather than "PPA") is a more apt name to the program option, because the "*actual PPA [is] a contract between the developer and the utility* [emphasis added]…."

[10] Walmart Exhibit 200 at page 8

July 26, 2019

TO: John Crider
Public Utility Commission of Oregon

FROM: Karla Wenzel
Manager, Pricing & Tariffs

PORTLAND GENERAL ELECTRIC
UM 1953 Phase II
PGE Response to OPUC Data Request No. 040
Dated July 12, 2019

Request:

PGE/500 Sims-Tinker/30:1-9. How would PGE recommend that the Commission ensure that a fair process occurs, by which PGE selects the least cost/risk project, outside of the competitive bidding process? What if the Company pursues a utility owned resource option?

Response:

Normally, PGE would explicitly follow the Competitive Bidding Rules making use of a full RFP process. However, as detailed in PGE/500 Sims-Tinker/30-31, the full RFP process adds time and cost to the procurement effort that does not align with customer interest nor the intent of the program and that ascribes significant additional costs making the product less desirable.

PGE recommends using a similar process to that used for the first tranche of the program. PGE is committed to a fair and transparent process whereby PGE makes resource criteria known ahead of time, solicits and accepts bids from all interested parties capable of meeting such criteria, and uses Commission approved evaluation methodologies. This process currently includes the opportunity for Staff and the Commission to review the criteria, bids, scoring, and the selected resource(s), which provides oversight in the process from procurement to resource contracting.

This process would apply to all resource types regardless of ownership structure. PGE is incentivized to procure the least cost/least risk project to ensure subscriber participation due to a competitive price, protections for cost-of-service customers and shareholders form uncompensated risks. If PGE were to offer a utility owned resource, PGE would make such offering known ahead of time and abide by the requirements of the Commission and rules to demonstrate no cost-shifting is occurring. The above detailed review process would provide Staff and the Commission with the necessary review opportunities and oversight of the overall process, ensuring a fair, transparent, and competitive outcome. Ultimately, the Commission has the authority to determine prudence and it is PGE’s responsibility to meet the burden of proof associated with supporting such determination.

Portland General Electric Company
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Erin E. Apperson
Assistant General Counsel

August 30, 2019

Via Email

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
P.O. Box 1088
Salem, OR 97308-1088

Re: LC 73 – PGE's 2019 IRP Addendum – Interim Transmission Solution

Attention Filing Center:

Enclosed for filing today, please find PGE's 2019 IRP Addendum – Interim Transmission Solution.

PGE plans to work with Staff and intervenors to establish a process to provide comments and participate in a workshop specifically focused on the proposed interim transmission solution. PGE believes that this process should occur concurrently with the existing 2019 IRP schedule to ensure adequate opportunity for stakeholder involvement.

Thank you in advance for your assistance.

Sincerely,

Erin E. Apperson
Assistant General Counsel

EEA:dm

Enclosure

Integrated Resource Plan

AUGUST 2019

Addendum to PGE's 2019 Integrated Resource Plan
Interim Transmission Solution

Addendum to PGE's
2019 Integrated
ResourcePlan

Interim Transmission Solution
AUGUST 2019

Contents

1 Introduction

The development and planned growth of renewable resources in the Northwest requires changes to the transmission system, in terms of both transmission development and utilization. Portland General Electric (PGE or Company) recognizes that the 2019 Integrated Resource Plan (IRP) renewable action provides an opportunity for the Company to contribute to continued learning about transmission utilization for renewable resources in the region. To support the 2019 IRP renewable action, PGE reassessed how the Company considers transmission within renewable procurement processes. In doing so, PGE weighed the cost and risk impacts to both customers and PGE, ensuring the proper balance between reliable deliveries of clean energy and continued renewable development. This is especially important during a period of changing regional policies and developing markets, where the challenges associated with the economical and reliable delivery of capacity and energy to serve customer needs are becoming increasingly complex.

Through careful consideration, comments provided by stakeholders, and discussions with regional partners, PGE developed a provisional program framework for its interim solution allowing for controlled learning, proper identification and allocation of risks and costs, and the ability to adjust or refine over time. The Company believes this proposal advances the utilization of the transmission system and enables least-cost and least-risk actions that provide value and clean energy to our customers and the region. This addendum presents the details of PGE's proposed provisional program and identifies how the program would be applied in the 2020 Renewable Request for Proposals (RFP).

Looking forward, PGE believes that continued development of renewables in the region will be necessary to implement clean energy policies and to meet greenhouse gas goals. Supporting this development while meeting PGE's commitments to customers will require broader transmission solutions that address both development and reliability concerns while being sufficiently flexible to adapt to changing landscapes. PGE is committed to furthering long-term, holistic solutions that enable continued renewable development to benefit customers, while appropriately addressing potential risks to both customers and PGE.

2 Background

In previous renewable RFPs, Bidders with projects outside PGE's service territory were required to provide achievable plans for acquiring long-term firm transmission service prior to the commercial operation date (COD). Bidders' transmission plans were also required to demonstrate long-term firm transmission service, in MWs, at an amount equal to the full nameplate rating of the proposed renewable resource. In some cases, conditional firm bridge was allowed to substitute for long-term firm, provided it converted to long-term firm within a pre-defined period.

Prior to filing the 2019 IRP, PGE held several stakeholder workshops and invited comments from stakeholders regarding the draft content and analysis of the 2019 IRP. Several parties provided feedback on transmission in the context of the IRP and a 2020 Renewable RFP. In the 2019 IRP, the Company acknowledged these comments and concerns by indicating it was working toward an interim solution, and identified several design principles to apply to developing such a solution:[1]

- Enable a fair, transparent, and competitive renewable resource procurement process
- Provide reasonable assurances of delivery, project success, and value to customers
- Adequately identify and mitigate potential cost shifts to customers and PGE
- Adequately identify and mitigate potential risk shifts to customers and PGE
- Appreciate differences between dispatchable and variable resources as appropriate

PGE used the above design principles and the guiding concept of a “comprehensive approach” to develop the provisional program.

3 Program Summary

As an interim solution, PGE is proposing a five-year provisional program that applies to renewable resource procurement processes conducted between 2019 and 2024.[2] The key elements of the program are:

- Applicable only to newly procured variable renewable resources pursuant to an IRP Action Plan or in support of voluntary renewable programs
- Eligible transmission service consists of one or a combination of the following products:[3]
    1. Long-Term Firm (LTF) transmission service
    2. Conditional Firm Bridge (CFB) transmission service with a Number of Hours curtailment option[4]
    3. Conditional Firm Reassessment (CFR) transmission service with a Number of Hours curtailment option[5]
- Eligible transmission service for at least 80 percent of the maximum output of the facility[6]
- PGE continues to require that output be delivered to PGE’s system

[1] *See* PGE’s 2019 IRP at 216.
[2] The provisional program will apply to renewable resources procured during this five-year period. In order to ensure that delivery requirements do not change during the life of the resource, the terms of this program will apply for the life of the resources procured during the five-year period.
[3] Conditional Firm Transmission Service is a type of Long-Term Firm transmission service for which there is a specified Number of Hours per year or a specified System Condition in which the Transmission Provider can curtail the reservation prior to curtailing other Long-Term Firm service. Conditional Firm service is charged at the same tariff rate as Long-Term Firm service. *See* BPA Conditional Firm Business Practice Version 23 available at https://www.bpa.gov/transmission/Doing%20Business/bp/tbp/Contitional-Firm-Transmission-BP-V23.pdf.
[4] CFB will convert to LTF service if the facilities identified in the customers CF Service Agreement or their equivalents are completed or if LTF service otherwise becomes available. *See* BPA Conditional Firm Business Practice Version 23.
[5] CFR only applies to Conditional Firm Service which is not based on a bridge (e.g. no build has been identified and approved). CFR may transition to CFB if an upgrade has been identified and approved or it may convert to LTF if the appropriate requests are in queue. BPA may perform a Reassessment of the Customer's Number of Hours or System Conditions no more often than once every two years. *See* BPA Conditional Firm Business Practice Version 23.
[6] Output is defined as the maximum deliverable quantity, expressed in MWs, that can be generated or delivered over one hour. Output may be limited by a bidder’s interconnection agreement, facility design, transmission rights, or contractual provisions.

Section 4 below presents the details, specifically the minimum thresholds and bid requirements, of how this provisional program would apply in the 2020 Renewable RFP.

The objective of the program is to provide an interim solution and allow for learning in a controlled manner, as the application of the key elements will have impacts decades beyond the provisional period. By applying the program to renewable RFPs executed during a limited window, PGE will have the opportunity to evaluate costs and risks associated with the approach and apply learning to future procurement activities.

3.1 Process Changes

An essential part of a comprehensive approach is assessing existing processes across the Company and determining appropriate modifications to align with the key elements of the program. PGE applied this approach during development of the provisional program to identify impacts to the various areas of PGE's business, both internal and external facing. Broadly, the Company categorized potential process changes to address risk and cost into two categories: RFP processes and business processes.

3.1.1 RFP Processes

Modifying PGE's transmission requirements, even under a provisional framework, introduces additional cost and risk to customers and PGE. In order to assess the impacts of these risks and attempt to appropriately mitigate them, PGE intends to make changes to certain elements of the RFP structure, specifically the scoring methodology and contract requirements.

Regarding the scoring methodology, PGE would adjust its capacity contribution/valuation methodology to account for any increased risk of delivery failure. Depending on the specific transmission plan of the bid, PGE would adjust the RECAP model to reflect the impacts of curtailment and long-term transmission for less than the full output, as reflected in the terms of the transmission service and coincident with the appropriate hours, on the capacity contribution of the resource. The impacts of this adjustment depend on the type of resource, its output profile, and its transmission plan, but will generally reflect the higher likelihood of curtailment and reduced delivery certainty associated with using conditional firm or long-term transmission for less than full output. Additionally, PGE would make changes to the non-price scoring methodology to assign points to non-quantifiable aspects, such as the difference in long-term availability between CFB and CFR service. CFR service inherently introduces more risk than CFB because it is not associated with a system upgrade and the reassessment terms and conditions create more uncertainty surrounding the changes to curtailment terms and its continued offering by the transmission provider.

Because the proposed transmission requirements introduce new risks for project deliverability, the RFP will reflect modifications to contract requirements to ensure these risks are addressed. The Company recognizes that certain events, curtailment or otherwise, may be outside the control of the parties and a contract must be flexible enough to address such events. However, changes to the transmission requirements result in a shifting of the risk allocation. PGE expects to address the increased deliverability risk by more clearly assigning deliverability responsibility to the supplier through more robust contract terms. Generally, these terms would address the quality of transmission procured for output above the level supported by long-term transmission, changes to the terms and conditions of the conditional firm service, minimum production guarantees, and failure to perform provisions should short-term transmission products not be available or the Bonneville Power Administration (BPA) cease to offer conditional firm service.

Historically, the Company has allowed bidders to assign transmission rights to PGE, which shifts the costs and management burden associated with the transmission service to PGE. The risks associated with accepting assignment of transmission rights was managed by the quality of the transmission service previously required. However, the transmission products accepted under the provisional program carry additional risk and management burden. Specifically, monthly firming and periodic reassessment of conditional firm service and the need to actively manage transmission service for up to 20% of the resource output.[7] Under procurement associated with the provisional program, PGE would not accept an assignment by default proposal from bidders. PGE would include contractual provisions that require commercially reasonable efforts to convert conditional firm service to LTF service when possible.
The Company would not explicitly require that conditional firm service be converted to LTF service regardless of cost. However, PGE would seek to ensure any existing conditional firm service is included in future BPA TSR Study and Expansion Processes (TSEP)[8] or future system expansion efforts in order to identify the costs of converting service.

3.1.2 Business Processes

PGE expects that changes would be required to existing business processes after the completion of an RFP. Many of these changes would be dependent on the composition of selected resource(s), specifically the transmission service and delivery plans. While PGE would endeavor to appropriately identify and evaluate costs and risks within an RFP process, it is possible that these costs or risks may manifest differently over time. The program framework would allow the Company to better track these changes and adjust its business processes to better accommodate changing operational paradigms, some of which are discussed below in Section 3.3.

At this point, readily identifiable impacts to existing business processes could include the purchase of short-term transmission service, carrying additional reserves, adjustments to next year output forecasts to account for expected curtailment or delivery amounts, and impacts to net purchases and sales of transmission and power. Notwithstanding the above RFP process efforts, it may be necessary and reasonable to reflect residual financial risks associated with renewable curtailment in PGE’s power cost forecasting dockets and/or consider changes to the regulatory policy for sharing variations in power costs. PGE would provide specific proposals during later regulatory processes as the details of such proposals depend heavily on the details of the resulting resource(s) and associated contract(s) from an RFP, the current effective or expected operational paradigm, regulatory mechanisms, regional policies, and experience gained during the provisional program.

3.2 Monitoring and Reporting

The key results of any provisional program are learning and experience. PGE would aim to implement or modify the necessary systems and business processes to appropriately identify and track the impacts of the program. By designing and implementing new processes, PGE can more effectively learn from the provisional program and make necessary adjustments or refinements to increase effectiveness while actively managing associated risks.

[7] *See* BPA’s Conditional Firm Business Practice, Section J.2.
[8] TSEP is the process by which BPA studies and evaluates requests for long-term transmission service.

These impacts cannot be fully known ahead of implementing the program and can vary from operational to financial. While some elements may be readily apparent, such as the amount of curtailment and the availability of long-term inventory, others are more difficult to identify at the outset, such as the impact to system operations in the form of additional reserves. Depending on the outcome of the resource procurement effort, PGE plans to initially monitor and report on the metrics in Table 1. Over time, these metrics may evolve, or indicators may be added or removed to ensure accurate results and useful reporting.

Table 1. Reporting metrics

Metric	Description
Conditional Firm Inventory	BPA publicly posts and regularly updates the amount of conditional firm inventory available for purchase. PGE would monitor these postings for changes over time.
Conditional Firm Usage	To the extent possible, PGE would monitor the usage of conditional firm inventory as a data point to determine if/how usage changes and if/how changes in usage impact existing users.
Conditional Firm Monthly Assessment Results	Ahead of each month, BPA can convert conditional firm service from NERC Priority Code 6-CF to 7-F depending on availability of short-term ATC. PGE would track the results of these "monthly firm up" actions when they occur.
Conditional Firm Curtailment	Conditional firm service has a NERC Priority Code of 6-CF and is curtailed prior to LTF, which has a NERC Priority Code of 7-F. PGE would track curtailment events that occur when Conditional Firm does not receive a "monthly firm up."
Impacts to Reserves	The proposed transmission requirements may result in the need to carry additional reserves, in the form of available generation, to handle events where output exceeds 80% or when there is a higher likelihood of a curtailment event.
Impacts to Operational Planning	In operations (e.g. next month, next day, etc.) PGE uses short-term forecasts to plan its system. These forecasts may adjust to reflect uncertainty regarding output or deliverability. PGE would seek to track these adjustments and determine their impacts to operational planning and costs.
Transmission Costs	Reducing the requirement for long-term transmission from 100% to 80% of output will increase the amount of short-term transmission products needed to ensure delivery during high-output periods. PGE does not yet know how these additional purchases will manifest as it depends on the final structure of the procured resource. Once the structure is known, PGE intends to track these additional costs.

PGE expects to report to the Commission and stakeholders via future IRP filings with a concluding report at the end of the provisional period. Future IRP filings after a resource has achieved COD will provide a reasonable cadence and venue to share the results and findings with interested parties. Ultimately, the results and findings from the program will inform PGE, stakeholders, the Commission, and regional partners as we collaboratively work toward a holistic solution to enable continued renewable development into the future.

3.3 External Policy Changes

The design and implementation of the program is based on current regional policies and operational paradigms, such as BPA's current product offerings and associated business practices detailing the implementation and use of these products. During the program period, these policies and paradigms may change, making future modifications necessary to conform to the then current practices. Such changes may be at the regional level, such as the expansion or evolution of the Energy Imbalance Market, or at the BPA level. The latter is more likely to have immediate impacts and present as changes in product offerings and terms, modified business practices or procedures, further enhancements and developments to TSEP. However, regional policy changes, such as a potential regional framework for resource adequacy or an expanded regional footprint for transmission planning, are likely to have broader and more uncertain impacts. In either case, the program framework and its implementation must remain sufficiently flexible to allow for necessary modifications to accommodate the uncertainty associated with changing paradigms. As part of its monitoring and reporting effort, the Company will seek to inform interested parties of changing dynamics and clearly identify modifications to the program or its implementation.

4 Conclusion

The Company looks forward to working collaboratively with parties in the 2019 IRP docket and a subsequent 2020 Renewable RFP docket to successfully implement the proposed provisional program. As indicated at the August 13, 2019 public meeting, PGE is open to holding an additional workshop ahead of the existing October 31, 2019 workshop to allow for PGE to present its proposal and answer clarifying questions. The Company will work with the parties to determine the level of interest and specific details.

Going forward, PGE continues to support a holistic solution that enables continued renewable development to benefit customers, while appropriately addressing potential risks to both customers and PGE. Such a solution will best allow PGE to balance reliable energy delivery and renewable development in order to continue to provide value to customers and achieve clean energy goals. The Company recognizes that pursuing such a solution will require significant effort and time on the part of PGE, the OPUC, stakeholders, and other regional entities. Efforts may start on a smaller scale, such as working with stakeholders to engage BPA on product improvements or product offering expansion, but collectively we should not lose sight of the desired end state.

5 2020 Renewable RFP Requirements

Eligible Transmission Service

The proposed 2020 Renewable RFP will allow for bidder participation for resources that have not received an offer for long-term firm transmission service. PGE will consider a range of specified transmission products as RFP eligible delivery strategies.

PGE will require that all resources have access to a specified quantity of long-term transmission from the project busbar to an accepted PGE point of delivery. Acceptable forms of long-term transmission include long-term firm, conditional firm bridge service, and conditional firm reassessment service (number of hours only – system condition service not accepted). Eligible long-term transmission products do not include non-firm, short-term firm, or unspecified transmission portfolio solutions. Resources must have sufficient long-term transmission rights to meet 80% of the project's maximum output capacity.[9] For the balance of the project, bidders may rely on short-term firm transmission products, but PGE will not accept deliveries on non-firm transmission.

For bidders proposing use of conditional firm reassessment service, PGE will only accept conditional-firm reassessment service whose curtailment frequency is limited by Number of Hours rather than enabled under specified System Conditions.[10]

Demonstration of RFP Eligibility

Bidders must demonstrate an achievable plan to secure required firm transmission service by the resource's commercial operations date. Achievable transmission service plans include either: a notice of available long-term firm inventory, a precedent transmission service agreement (PTSA), existing transmission service reservations delivering to PGE, a request or offer of transmission service (either redirect or original) with consideration for conditional firm service[11], a plan of service identified in a completed transmission service study (cluster study or individual study), demonstrated participation in an ongoing transmission study (cluster study or individual study).

Requirements Prior to Final Short-list

In order to remain an eligible bidder on PGE's final short-list, bidders must have received an acceptable offer of required transmission service by December 31, 2020. Acceptable offers of transmission service include: a full offer of transmission service, an executable PTSA, offer of conditional firm transmission service, or a proposed plan of service identified from a transmission study for which the bidder has received completed preliminary engineering results and has signed an Environmental Review Agreement.

Price Scoring Impacts

Transmission service is expected to impact project performance and value to PGE's customers. These impacts are expected to be most notable in the provision of capacity necessary to meet PGE's peak capacity needs. For this reason, PGE's determination of capacity value will account for the transmission service included in the project offer.

PGE's capacity value estimation methodology will only credit capacity value for the portion of a resource served on long-term transmission (including LTF, CFB, CFR). Capacity value will not be assessed for the portion of the resource expected to be served on short-term firm. Furthermore, for those resources that plan to rely on conditional firm service, the expected output of the resource will be diminished by the number of hours of allowed curtailment identified in the transmission service offer or plan.[12] PGE's methodology will assume that the curtailment occurs in those hours in which PGE experiences the greatest capacity need as it is

[9] A project's AC or DC nameplate capacity may differ than the maximum output. Output is defined as the maximum deliverable quantity, expressed in MWs, that can be generated or delivered over one hour. Output may be limited by a bidder's interconnection agreement, facility design, transmission rights, or contractual provisions.
[10] *See* BPA Conditional Firm Business Practice Version 23, Section B.3.
[11] *See Id.*
[12] If a conditional firm offer does not identify the Number of Hours, PGE will use its experience and available supporting data to assess the Number of Hours for determining the price score.

reasonable to assume that the curtailment occurs during the periods of greatest system stress also experienced by PGE.

Non-Price Scoring Impacts

Transmission service is an important risk factor for PGE to consider in its non-price scoring assessment. Offers that propose relying on long-term transmission service to serve only a portion of resource output and offers that propose utilizing conditional firm service present long-term risks that cannot be accurately captured in PGE's price scoring assessment. Such transmission service arrangements may lead to a greater number of curtailment events should short-term transmission service availability be limited or should conditional firm service be reassessed or withdrawn. For this reason, PGE's non-price scoring assessment will assign higher non-price scores to those offers which have greater shares of long-term service and to those offers that rely on long-term firm service as opposed to conditional firm service.