Portland General Electric Company
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August 19, 2020

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Ste. 100
P.O. Box 1088
Salem, OR 97301-1088

RE: UM 1953 – Portland General Electric Company Phase 2 Rebuttal Testimony

Filing Center:

Portland General Electric Company (PGE) hereby submits rebuttal testimony and accompanying exhibits to provide additional information regarding PGE's proposed updates to the Nine Conditions, originally adopted in Commission Order 16-251, and tranche 2 of its Green Affinity Energy Rider program. Enclosed for filing in the above referenced matter is:

- PGE / 800 – Testimony of Karla Wenzel and Brian Faist
- PGE / 801 – GEAR Tranche 2 Modified Request for Proposal Process
- PGE / 802 – Risk Adjustment Scenarios

If you have any questions, please call me at (503) 464-7805. Please direct all formal correspondence, questions, or requests to the following email: pge.opuc.filings@pgn.com.

Sincerely,

/s/ *Karla Wenzel*
Karla Wenzel
Manager, Regulatory Strategy and Policy

Enclosure

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UM 1953

Green Tariff

PORTLAND GENERAL ELECTRIC COMPANY

Testimony of

Karla Wenzel
Brian Faist

August 19, 2020

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I. Introduction

Q. Please state your names and current positions.

A. My name is Karla Wenzel. I am the Manager of Regulatory Policy and Strategy at Portland General Electric Company (PGE or the Company). My qualifications were provided in PGE Exhibit 700.

My name is Brian Faist. I am a Principal Originator at PGE. My qualifications are provided at the end of this testimony.

Q. What is the purpose of your testimony?

A. The purpose of this rebuttal testimony is to respond to reply and cross answering testimonies regarding issues on which there is a lack of agreement among parties to this proceeding. The reply testimonies were filed by the Public Utility Commission of Oregon (Commission or OPUC) Staff (Staff), Northwest & Intermountain Independent Power Producers Coalition (NIPPC), PacifiCorp (PAC), Renewable Northwest (RNW), and Walmart Inc. and Sam's West, Inc (Walmart). While Alliance of Western Energy Consumers (AWEC), Avangrid Renewables LLC (Avangrid), Calpine Energy Solutions, NW Energy Coalition, and Oregon Citizens Utility Board (CUB) are parties in this docket, they did not file reply testimony. Collectively, all these entities are referred to as "Parties".

Q. Please re-state what you are requesting in Phase 2 of this proceeding.

A. Regarding the Commission's original Nine Conditions, adopted in Order No. 16-251,[1] we request the Commission to update the conditions as set forth Section II.E. of this testimony.

[1] Public Utility Commission of Oregon. "Order 16-251". UM 1690. Public Utility Commission of Oregon. 5 Jul 2016. Retrieved from https://apps.puc.state.or.us/orders/2016ords/16-251.pdf

Regarding PGE's Green Energy Affinity Rider (GEAR) program design and program operation for tranche 2, we request the Commission to:

- Approve the GEAR as a total of 500 megawatts (MW);
- Approve the Customer-Supplied Option (CSO) minimum customer size requirement at 10 average megawatts (aMW), consistent with tranche 1;
- Acknowledge that the breadth of risk, beyond those discussed in our Phase 1 testimony, brought to PGE by the GEAR, should be borne by subscribers via the risk adjustment fee;
- Approve the continued application of the method from tranche 1 to tranche 2 for the calculation of the energy and capacity credits;
- Grant a waiver of the Competitive Bidding Rules (CBRs);
- Approve our proposal that the interim transmission solution outlined in PGE's 2019 Integrated Resource Plan (IRP) Addendum on August 30, 2019 be applied to Voluntary Renewable Energy Tariff (VRET) procurement;
- Affirm our approach to addressing the GEAR interactions within the IRP is reasonable; and
- Adopt our recommended 90-day process for the GEAR to offer subsequent tranches once tranche 2 is full.

Q. Do you have any alternate requests?

A. Yes. We propose the following in the event that the Commission does not approve three of our primary proposals listed, above:

- Should the Commission not waive the CBRs, allow us to conduct a modified Request for Proposal (RFP) process, discussed in PGE Exhibit 801;

- Should the tranche 2 size of 200 MW not be approved, determine a reasonable PGE-Supplied Option (PSO) size and establish a process for determining case-by-case CSO applications, discussed in Section III.A of this testimony; and
- Should the Commission choose to keep some version of Condition 6, acknowledge, as it did in Phase 1 of this docket, that Condition 6 does not apply to cost-of-service (COS) riders (discussed further in Section II.B of this testimony) and that a strict application of each of the Nine Conditions to the GEAR is not required.

Q. Have PGE and Parties settled any of the issues in Phase 2 of this docket?

A. No. While we have not entered into any stipulations, Parties' testimonies suggest support or a lack of disagreement on several issues.

Q. What are the issues that PGE and Parties appear to agree on?

A. Other than NIPPC, who generally opposes any changes to the Nine Conditions,[2] there was no opposition[3] from the other Parties in testimony on the following:

- Condition 2 – The current language, as updated in Order 19-075, reads:

> Voluntary renewable energy options should only include bundled [Renewable Energy Credit or 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.[4]

We proposed, and most Parties support,[5,6,7,8] a change to the condition to the following (italicized to show changes, deletions not shown): "*VRET* options only

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[2] NIPPC/300, page 11.
[3] PGE notes that some parties simply did not address some of these items.
[4] Public Utility Commission of Oregon. "Order 19-075". UM 1953. Public Utility Commission of Oregon. 5 Mar 2019, page 2. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-075.pdf
[5] CUB/200, pages 12-13.
[6] PAC/100, page 3.
[7] RNW/300, page 12
[8] Staff/400, page 9.

include bundled REC products. Any RECs associated with serving participants must be retired by or on behalf of *the* participants."[9]

- Condition 3 – The current language, as updated in Order 19-075, reads: "The year that a voluntary renewable energy program eligible resource became operational should be no earlier than 2015."[10] We proposed, and most Parties support,[11,12,13,14] a change to the condition to the following (italicized to show changes, deletions not shown): "The year that *a VRET*-eligible resource *becomes* operational should be no earlier than *one year prior to program enrollment*." In addition, Staff proposes that the term "program enrollment" be defined as when a customer signs a binding agreement to participate in the program.[15] We support Staff's added definition.
- Condition 4 – The current language reads: "The VRET program size is limited to 300 aMW for PGE and 175 aMW for PacifiCorp."[16] Parties support[17,18] our proposal to convert the cap's unit of measure from average megawatt to megawatt, or resource nameplate. This will align with the total approved tranche 1 (300 MW) and the proposal for tranche 2 (200 MW). However, the tranche 2 capacity amount is still unresolved (see Section III.A, below).

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[9] PGE/500, page 25.
[10] Public Utility Commission of Oregon. "Order 19-075". UM 1953. Public Utility Commission of Oregon. 5 Mar 2019, page 2. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-075.pdf
[11] CUB/200, page 13.
[12] PAC/100, page 3.
[13] RNW/300, page 12.
[14] Staff/400, page 9.
[15] Id.
[16] Public Utility Commission of Oregon. "Order 16-251". UM 1690. Public Utility Commission of Oregon. 5 Jul 2016, page 31. Retrieved from https://apps.puc.state.or.us/orders/2016ords/16-251.pdf
[17] RNW/400, page 4.
[18] Staff/400, page 10.

- Condition 9 – The current language reads: "All VRET offerings must be made publicly available and subject to review by the Commission to ensure they are fair, just, and reasonable."[19] Other than Staff,[20] no other party mentioned this as an issue in their testimony. Therefore, we assumed that Parties support maintaining this condition as originally approved.
- Transmission Requirements – Staff[21] supports our proposal that the interim transmission solution outlined in PGE's 2019 IRP Addendum on August 30, 2019 be applied to the GEAR procurement.[22] No other party mentioned this as an issue in their testimony.

Q. Are there any issues to which you previously opposed but now agree, considering Parties' testimonies?

A. Yes. We now agree with the following:

- Condition 5 – The current language, as updated in Order 19-075, reads: "Voluntary renewable energy product design should be sufficiently differentiated from existing direct access programs."[23] We agree with CUB,[24] RNW,[25] and Staff[26] to maintain this language as currently written. However, there is a general disagreement around the meaning of "sufficiently differentiated" and how this condition interacts with Condition 6, which is discussed in Section II.B of this testimony.

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[19] Public Utility Commission of Oregon. "Order 16-251". UM 1690. Public Utility Commission of Oregon. 5 Jul 2016, page 4. Retrieved from https://apps.puc.state.or.us/orders/2016ords/16-251.pdf
[20] Staff/300, page 21.
[21] Ibid, page 24.
[22] RNW/300, page 17.
[23] Public Utility Commission of Oregon. "Order 19-075". UM 1953. Public Utility Commission of Oregon. 5 Mar 2019, page 2. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-075.pdf
[24] CUB/200, page 15.
[25] RNW/300, page 10.
[26] Staff/400, page 11.

- We agree with NIPPC to maintain the CSO and PSO distinction, consistent with tranche 1; therefore, the 200 MW proposed for tranche 2 would be allocated 100 MW for the CSO and 100 MW for the PSO.

Q. How is the rest of your testimony organized?

A. We have organized our testimony on the unresolved issues as follows:

1) PGE's Proposed Updates to the Nine Conditions
   a) Condition 1
   b) Condition 6
   c) Condition 7
   d) Condition 8
   e) Summary of PGE's Proposed Updates to the Nine Conditions
2) GEAR Tranche 2 Program Design
   a) Make the GEAR 500 MW
   b) Customer Size Requirements
   c) Risk Adjustment Fee
   d) Calculation of the Energy and Capacity Credits
3) GEAR Tranche 2 Resource Procurement and Long-Term Planning
   a) Utility Ownership of GEAR Resources
   b) Competitive Bidding Rules (CBRs)
   c) Integrated Resource Plan (IRP) Interactions
   d) Post Phase 2 Process
4) Summary
5) Qualifications

II. PGE's Proposed Updates to the Nine Conditions

Q. Please refresh the understanding of these conditions and their origin.

A. When the Oregon Legislature passed House Bill (HB) 4126 in 2014, the law directed the Commission to study whether allowing a utility to offer VRETs was in the public interest.[27] After a lengthy investigation and no specific proposal on which to base them, Staff proposed conditions for the Commission's consideration and with a few changes, the Commission adopted them.[28] In addition, the conditions were further updated in Commission Order 19-075.[29] Given the lapse of time since the conditions were first adopted and that the GEAR offered an opportunity to examine the conditions in light of an actual program, the Commission stated its intent to review and reconsider the conditions in Phase 2 of this docket.[30]

Q. Please summarize your Phase 2 request regarding the Nine Conditions.

A. There are two issues in question that we discuss as part of this testimony:

1. Proposed updates of the Nine Conditions for Commission consideration; and
2. Our request for Commission approval of the GEAR tranche 2.

Q. Generally, what are Parties' positions on updating the Nine Conditions?

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[27] 77th Oregon Legislative Assembly. "Oregon House Bill 4126." 2014 Regular Session. Oregon State Legislature. 11 Feb 2014. Retrieved from https://olis.leg.state.or.us/liz/2014R1/Downloads/MeasureDocument/HB4126
[28] Public Utility Commission of Oregon. "Order 16-251". UM 1690. Public Utility Commission of Oregon. 5 Jul 2016. Retrieved from https://apps.puc.state.or.us/orders/2016ords/16-251.pdf
[29] Public Utility Commission of Oregon. "Order 19-075". UM 1953. Public Utility Commission of Oregon. 5 Mar 2019, pages 2-3. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-075.pdf
[30] Ibid, page 8.

A. There has been general support to update the Nine Conditions from CUB,[31] PAC,[32] and RNW.[33] However, NIPPC opposes making any updates.[34] Although Staff's initial testimony identified multiple areas where they supported updates, their reply testimony could be read as a step back.[35]

Q. On what basis does NIPPC oppose making any updates to the Nine Conditions?

A. NIPPC states that the Commission did not determine in Phase 1 that it was appropriate to change the Nine Conditions.[36]

Q. Do you agree with NIPPC's assertion?

A. No. In fact, the Commission stated the opposite in Order 19-075:

> As part of Phase 2 of this proceeding, we will *review and reconsider the Nine Conditions* for VRET program development we identified in Order No. 16-251. 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. In approving PGE's program, we apply flexibility in applying the Nine Conditions, because we do not require exactly the same terms and conditions as the [DA] program.
>
> This reflects our view that *significant differences* in the ways a utility offering and the [DA] program affect cost-of-service customers may warrant different terms and conditions for the programs. A review of the Nine Conditions *is appropriate* in light of these differences and the clarity offered by a specific proposal from PGE (emphasis added).[37]

Q. Has NIPPC been consistent on this issue?

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[31] CUB/200, page 11.
[32] PAC/100, page 1-2.
[33] RNW/300, page 12.
[34] NIPPC/300, page11.
[35] Staff states that they do "not find it reasonable to amend the conditions based on the specific circumstances of PGE's GEAR when future changes to the GEAR or another future VRET may not follow the same structure... [and that] these conditions apply to any future VRET as well as PGE's currently approved and proposed GEAR." Source: Staff/400, page 5.
[36] NIPPC/300, page 10.
[37] Public Utility Commission of Oregon. "Order 19-075". UM 1953. Public Utility Commission of Oregon. 5 Mar 2019, page 8. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-075.pdf

A. No. We note that NIPPC Exhibit 200 states that Phase 2 was to include "whether the 'nine conditions' the Commission established as requirements for a VRET to be within the public interest remain appropriate…"[38] and they quote the Commission's recommendation in Order 19-075,[39] shown above.

Q. Despite the Commission's intent to assess changes in the competitive supply market and the renewable energy development market since 2016,[40] NIPPC has continuously stated that nothing has changed to warrant alteration of the Nine Conditions.[41,42] How do you respond?

A. In addition to the changes detailed in our opening testimony,[43] other changes have occurred in the competitive electricity supply market since 2016 including the following:

- Greater opportunities for the competitive retail electricity supply market in the Commission's creation of New Large Load Direct Access (NLDA), resulting in a PGE program of 119 aMW, that is in addition to the existing Long-Term Direct Access (LTDA) program of 300 aMW;
- An increase in average megawatts and customer accounts in direct access service (DA)[44] from 178 aMW (218 points of delivery, or PODIDs) on LTDA and 15 aMW (190 PODIDs) on Short-Term Direct Access (STDA) in 2015, to 236 aMW (303 service point identifications, or SPIDs) on LTDA and 18 aMW (344 SPIDs) on STDA in January 2020;

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[38] NIPPC/200, pages 3-4.
[39] Ibid, page 6.
[40] Public Utility Commission of Oregon. "Order 19-075". UM 1953. Public Utility Commission of Oregon. 5 Mar 2019, page 8. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-075.pdf
[41] NIPPC/300, page 10.
[42] NIPPC/200, page 6.
[43] PGE/500, page 20.
[44] PGE defines DA programs as including Short-Term (STDA), Long-Term (LTDA), and New Large Load (NLDA).

- An increase in the number of registered electricity service suppliers (ESSs) in our service territory from three to five with the registration of Avangrid (2016) and 3 Phases Renewables (2017);[45]
- An increase of eight aggregators registered to aggregate customer loads for DA; and
- Regarding renewable energy since 2016:
  - Beaverton (2019)[46] and Milwaukie (2018)[47] joined Multnomah County[48] and City of Portland[49] in adopting 100% clean electricity goals (or carbon neutral goals) between 2020 and 2035;
  - The passage of Oregon's Clean Energy & Coal Transition Plan that increases Oregon's Renewable Portfolio Standard (RPS); and
  - The Commission's approval of tranche 1 of the GEAR, which relies on the market for the underlying renewable resource.

While difficult to show renewable development activity, it is logical to assume that development activity has increased to meet the growing demand. We address additional changes to the renewable development market in the discussion regarding Condition 7 in Section II.C, below.

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45 As reported by PGE's DA Operations.
46 "Climate Action Plan." Sustainability. Beaverton Oregon. Retrieved from https://www.beavertonoregon.gov/399/Sustainability
47 "Milwaukie is Taking Climate Action." Climate Action. City of Milwaukie. Retrieved from https://www.milwaukieoregon.gov/sustainability/climateaction
48 "2015 Climate Action Plan." Sustainability. Multnomah County. Retrieved from https://multco.us/sustainability/2015-climate-action-plan
49 "History and key documents of climate planning and action in Portland." Climate Action. City of Portland. Retrieved from https://beta.portland.gov/bps/climate-action/history-and-key-documents-climate-planning-and-action-portland

Q. Is it also important to review and reconsider the Nine Conditions in the context of an actual VRET?

A. Yes. We agree with PAC's observation that the Nine Conditions were developed in a separate proceeding where they were being drafted and reviewed without context of an actual proposal.[50] We also agree with the Commission's statement that a "review of the nine conditions is appropriate in light of ...the clarity offered by a specific proposal from PGE".[51] We would add that in developing and implementing the GEAR, we have developed experience that is informing our recommendation for updating these conditions to help guide future VRET designs.

While we understand Staff's interest in seeking to ensure that recommendations regarding condition language for all VRETs are not based on PGE's one design, for Staff to summarily dismiss modifications seems short-sighted. It would also be a missed opportunity to refine the conditions in a real-world setting, as opposed to using theoretical scenarios, especially after we successfully implemented tranche 1 (with stakeholder input). In any event, this is in line with Commission's actions in approving the GEAR tranche 1 where it applied "flexibility" in the Nine Conditions.[52]

Finally, we agree with Staff's statement regarding the general applicability of the conditions but clarifies that given the Commission's decision on tranche 1, the results of the current review of these conditions would only apply prospectively.[53]

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[50] PAC/200, page 2.
[51] Public Utility Commission of Oregon. "Order 19-075". UM 1953. Public Utility Commission of Oregon. 5 Mar 2019, page 8. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-075.pdf
[52] Id.
[53] Id.

Q. What experience have you gained that is informing your proposals for the Nine Conditions?

A. Some examples are that we learned the amount and type of customer demand for a VRET, and specifically the GEAR based on the demand during tranche 1. This information informed our proposal to refine the VRET cap in Condition 4 to be based on renewable resource nameplate and remove ambiguity of our calculation/application and revise Condition 3 to ensure the resource was "new" based on customer preferences.

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

Q. Please state the current language of Condition 1 and Parties' proposed modifications.

A. The current language reads: "Renewable Portfolio Standard (RPS) definitions of resource type, location, and bundled Renewable Energy Certificates (RECs) must apply to VRET products."[54]

Staff,[55] RNW,[56] and CUB[57] all support including energy storage with the renewable resource generation, eligible to support a VRET. While expressing concerns that inclusion of energy storage may impact DA offerings due to the credit calculation, Staff proposes the change in this condition be applied prospectively and require any VRET resources with energy storage to receive explicit Commission approval for the credit calculation.[58]

Q. Do you agree with the proposal to include energy storage?

[54] Public Utility Commission of Oregon. "Order 16-251". UM 1690. Public Utility Commission of Oregon. 5 Jul 2016, page 30. Retrieved from https://apps.puc.state.or.us/orders/2016ords/16-251.pdf
[55] Staff/400, page 6.
[56] RNW/400, pages 15-17.
[57] CUB/200, pages 11-12.
[58] Staff/400, page 7.

A. No. We note that the enabling statute does not include energy storage in the definition of qualifying resources.[59,60]

B. Condition 6 (Explicitly Linking VRETs to DA)

Q. Please state the current language of Condition 6.

A. The current language (also called "the mirroring condition") reads:

> VRET terms and conditions (including the timing and frequency of offerings), as well as transition costs, must mirror those for direct access. PGE and PacifiCorp may propose VRET terms and conditions that differ from current direct access provisions but must propose changes to their respective direct access programs to match those changes.[61]

Q. Earlier in testimony, you note agreement to maintain Condition 5 regarding sufficient differentiation between VRETs and DA. What is your proposal regarding Condition 6?

A. We propose to eliminate Condition 6 as it seems to contradict Condition 5.[62] If a utility's VRET is required to be sufficiently differentiated, then it runs counter to require the terms be mirrored—to result in no longer being differentiated. In addition, Condition 4 sets the cap for the VRET and if there is an allegation that the VRET design unfairly impacts DA, then Condition 9 allows evaluation of the impacts.

Q. Why do you continue to propose removing Condition 6?

A. Although we support maintaining Condition 5, there is general disagreement as to the meaning of "sufficiently differentiated" and how Condition 6 is then applied. If "sufficiently differentiated" means "that [VRET and DA] not directly compete with each other for the same

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[59] "ORS 469A.020 (Qualifying electricity)." Chapter 469A. OregonLaws.org. Retrieved from https://www.oregonlaws.org/ors/469A.020
[60] "ORS 469A.025 (Renewable energy sources)." Chapter 469A. OregonLaws.org. Retrieved from https://www.oregonlaws.org/ors/469A.025
[61] Public Utility Commission of Oregon. "Order 16-251". UM 1690. Public Utility Commission of Oregon. 5 Jul 2016, page 3. Retrieved from https://apps.puc.state.or.us/orders/2016ords/16-251.pdf
[62] PGE/500, pages 26-27.

customers,"[63] then Condition 6 is not only contradictory to Condition 5, but also adversely limiting to VRETs. In other words, if the programs do not directly compete, then:

- How would they appeal to the same customer need; and
- Why require a matching of the terms and conditions of VRET design to DA, which inherently would no longer make them "sufficiently differentiated"?

In addition, we do not believe that the Commission intended to give the utility the ability to modify the terms of the DA program to reduce that cap to match a significantly lower cap of the VRET program.

Q. Should the Commission not be inclined to remove Condition 6, do you have an alternate proposal?

A. Yes. We recommend the following proposal from PGE Exhibit 600, which was based on Staff's original language (italicized to show changes to Staff's language):[64]

> *If a utility seeks to offer a VRET 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.[65]

Q. Your modified language makes Condition 6 applicable to VRET designs that are not COS. Please explain your rationale.

A. There are two possible VRET designs:

- COS Rider Design – The customer load continues to be served through COS, with their load continuing to be planned and procured exclusively through the utility;

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[63] Staff/400, page 18.
[64] Staff/300, page 20.
[65] PGE/600, page 22.

therefore, the VRET is <u>*incremental*</u> to the services provided through COS and is substantially differentiated from existing DA programs.

- Non-COS Design – The customer's participation in the VRET is in <u>*lieu*</u> of a utility providing services through COS, with the customer's load served exclusively via the VRET.

The latter design is the same service as what an ESS provides through DA (in lieu of COS). For such a circumstance, we would agree that Condition 6 be applied to minimize the impact to the competitive market as the design encourages participation beyond the current uptake of DA.

Q. What are the Parties' current views regarding Condition 6?

A. CUB[66] and PAC[67] support deletion. Staff opposes both deletion and our alternate modification to Condition 6. Although RNW neither supports nor opposes our proposal, RNW proposed a reporting requirement because "...process barriers upfront may restrict innovation and slow system transformation and greenhouse gas-emission reduction."[68] NIPPC did not support changes to any of the conditions[69] but suggests that the GEAR could be granted a "limited waiver"[70] if certain restrictions were met. We address the Parties' specific arguments below.

[66] CUB/200, page 15.
[67] PAC/100, page 5.
[68] RNW/400, page 6.
[69] NIPPC/200, page 9.
[70] NIPPC/300, pages 3-4.

Q. Staff's primary concerns are that your proposals would be detrimental to the competitive marketplace[71] and that a COS rider unfairly competes with DA.[72] How do you respond to these concerns?

A. We address the following issues that Staff asserts, but are not true, regarding VRETs:

- VRET Cap – Staff states that the VRET cap has "more cap space than is currently available under PGE's LTDA program";[73] however, Staff misinterprets the magnitude of the VRET cap. In fact, the approved VRET cap for tranche 1 of 300 MW and our current proposal to make the GEAR 500 MW converts to about 150 aMW.[74] This amounts to only half the size of our current total LTDA program (300 aMW) and even less as the new NLDA program increases the total DA program size to 419 aMW. In addition, this undermines Staff's argument for the inclusion of language in Condition 7 regarding the competitive market (as discussed in Section II.C, below).
- Utility Relationship – Staff suggests more than once that maintaining customer relationships with the utility provides an unfair advantage over DA.[75] Unfortunately, Staff provides no support for this assertion. ESSs are not necessarily small, unsophisticated entities with limited knowledge of customers or competitive environments. To the contrary, they are typically sophisticated, large, multi-national companies with significant experience in developing products and

[71] Staff/400, page 17.
[72] Id.
[73] Id.
[74] Assuming PGE sourced from one generating facility and the facility had a 30% capacity factor (approximate for solar resource), PGE's proposal to increase the GEAR by 200 MW equates to a 60 aMW increase which makes the full 500 MW of GEAR equivalent to 150 aMW. This capacity factor is an approximate as stated in PGE/600, page 12.
[75] Ibid, page 11.

marketing them in a variety of settings without the limitations placed on us as a regulated entity. Therefore, we do not have an unfair advantage in 'maintaining customer relationships' as ESSs can, and do, develop and maintain their own customer relationships.

- Price Assurance – Staff argues that the VRET's ability to offer greater price assurance provides us with an unfair competitive advantage.[76] We do not understand how Staff arrived at this conclusion since there is nothing preventing an ESS from providing solutions that give its customers some level of price assurance. Being able to offer price assurance on an energy solution is a power supply decision. The more an entity relies on short-term market power purchases, the more volatile their pricing may be. Relying on a higher percentage of short-term market power purchases is a choice often made during low market price environments, but nothing prevents an entity from relying more on physical resources or long-term contracts which lessens the exposure to market prices.

Lower Power Prices – We are uncertain what Staff means when they say that the VRET provides customers with access to "lower power prices available in the wholesale market."[77] If Staff is referring to the price a VRET, or similarly COS, customer pays for energy, Staff appears to contradict this elsewhere in their testimony where they suggest that: (1) DA appeals to customers that value their "individual economic and environmental goals" implying that DA customers pay lower rates;[78] and (2) saving money on bills "is typically within the purview of

[76] Ibid, pages 17 and 29.
[77] Staff/400, page 18.
[78] Ibid, pages 18-19.

[DA]."[79] If Staff is suggesting that we can procure power from the wholesale market at a lower price than an ESS, this claim is unsubstantiated and mistaken. The wholesale market is equally available to all ESS providers (as it is to PGE) and, as stated above, all of which are sophisticated wholesale energy market participants. There is significant Federal Energy Regulatory Commission oversight in the wholesale energy market to ensure that no one party has undue influence (market power) in the market. To suggest that we have an advantage in the wholesale energy market ignores the realities of the structure and regulatory oversight of that market. Furthermore, it ignores that wholesale purchases are only a portion of overall total COS rates and a VRET is not explicitly linked to the wholesale market, but rather to the associated renewable resource.

In addition, Staff also suggests that fixed credit methodology and the VRET customer's ability to avoid transition charges results in unfair competition with DA.[80] These are both dependent on the VRET design, and so we address them separately below.

- Fixed Credit Methodology – Staff noted that their position in Phase 1 was that a "fixed credit methodology which allows the participant to realize energy prices below COS rates would present an unfair advantage for the VRET over DA programs."[81] This could be true but ignores the overall cost of the DA offering, which theoretically could still be lower than COS plus a VRET. Regardless, if the Commission finds that Staff's scenario of a fixed credit methodology representing a competitive advantage is a valid concern, we would be supportive of explicitly

[79] Ibid, page 13.
[80] Ibid, page 17.
[81] Id.

requiring that a VRET COS rider cannot result in a rate below COS. This is like the GEAR, as approved by the Commission in tranche 1,[82] where a customer could not use the credit for cost savings.

- Transition Costs – Transition costs are a contribution from DA customers to COS customers to offset the cost of resources that we planned and procured to meet the customer's load before they elected DA. In instances where the VRET is a COS rider, subscribers remain COS customers and fully contribute to the resources that we planned and procured to meet their loads. Therefore, a separate transition charge is not only unnecessary, but would be double charging. In addition, the GEAR's design as a COS rider does not allow a customer to leave our COS supply, which means that they contribute to state mandates and reliability costs through our generation resources. Unlike the LTDA and NLDA programs, where customers are free from transition adjustments after five years, the GEAR customer does not stop paying for the resources that we planned and procured. However, in the instance where the VRET design allows a subscriber to exit or bypass COS-related charges associated with those planned and procured resources, we could envision the application of a transition adjustment to such VRET design.

Q. Staff states that "should the Commission adopt Staff's language or otherwise maintain or amend Condition 6, the proper course of action would be to direct the Utility to address differences in the VRET and DA in UM 2024."[83] Do you agree?

[82] Public Utility Commission of Oregon. "Order 19-075". UM 1953. Public Utility Commission of Oregon. 5 Mar 2019, page 5. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-075.pdf
[83] Staff/400, page 27.

A. No. If the Commission maintains Condition 6, they could apply the same flexibility as they did in Phase 1, to not require the same terms and conditions as the DA program.[84] Even if the Commission were to direct us to review the GEAR design in light of the mirroring condition before tranche 2 is offered, we could choose to propose changes to the GEAR tranche 2; make changes to DA; or provide explanation of good cause for not mirroring (provided that is allowed in the Condition 6 language). Regarding UM 2024, we acknowledge that the design elements of DA are in scope.

Q. Please summarize RNW's proposal to maintain Condition 6 and establish annual reporting requirements.

A. As stated earlier, RNW neither supports nor opposes the modification or removal of Conditions 5 and 6. Instead, they propose that the utility submit "an annual report detailing both green tariff and [DA] activity…to demonstrate that both programs are truly available to interested customers and that the green tariff product is not disrupting the competitive marketplace."[85] If that reporting shows a significant impact by either program, then RNW proposes an investigation be opened regarding the relationship between the two programs.[86]

Q. Do you support a reporting requirement on VRETs and DA as RNW proposes?

A. Yes. We appreciate RNWs creative solution, to an issue which has been difficult to resolve with Parties, that is geared toward promoting innovation and avoiding lengthy regulatory hurdles. Consequently, we are willing to work with Parties to determine measurable and meaningful metrics in a report that would signal changes in the relationship between a VRET and DA that could be detrimental to either program. We also note that if future tranches were

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[84] Public Utility Commission of Oregon. "Order 19-075". UM 1953. Public Utility Commission of Oregon. 5 Mar 2019, page 8. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-075.pdf
[85] RNW/300, page 10.
[86] RNW/400, pages 4-5.

offered, Staff could request the information and examine impacts when the tariff proposal is filed.

Q. Do you agree with NIPPC's proposal to maintain Condition 6 and allow you to submit a waiver of the condition if it meets specific criteria?

A. No. A utility could make a case as to why a condition should be waived. We do not agree with the criteria NIPPC lists that need to be met to waive Condition 6, specifically.[87] These criteria effectively add additional constraints to the VRET, which is inappropriate and does not serve customer interests or the decarbonization goals of the State. As stated earlier, the Commission applied flexibility for the GEAR tranche 1 in not requiring "exactly the same terms and conditions as the [DA] program."[88] Therefore, we do not find it unreasonable for the Commission to do so again, which is more streamlined and does not add unnecessary process for the Commission and Parties.

C. Condition 7 (Utility Ownership of a VRET Resource)

Q. Please state the current language of Condition 7.

A. The current language reads:

> The regulated utility may own a VRET resource, but may not include any VRET resource in its general rate base. It may recover a return on and return of its investment in the VRET resource from the VRET customer; however, the utility must share some of the return on with the other utility customers for ratepayer-funded assets used to assist the VRET offering.[89]

Q. What do you propose for Condition 7?

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[87] NIPPC/300, page 4.
[88] Public Utility Commission of Oregon. "Order 19-075". UM 1953. Public Utility Commission of Oregon. 5 Mar 2019, page 8. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-075.pdf
[89] Public Utility Commission of Oregon. "Order 16-251". UM 1690. Public Utility Commission of Oregon. 5 Jul 2016, pages 3-4. Retrieved from https://apps.puc.state.or.us/orders/2016ords/16-251.pdf

A. We propose to modify this condition to state the following (italicized to show additions, deletions not shown): The regulated utility may own a VRET resource, *and when it does, it must continue to ensure there is no cost shifting to non-participants*.[90] Our proposal includes language that aligns with HB 4126 and eliminates the prohibition on rate base and the requirement of sharing some of the return with other utility customers.

Q. Why are you proposing to eliminate the rate base prohibition and the sharing requirement?

A. While the Commission's conditions allow for utility ownership of a VRET resource, Condition 7's prohibition against inclusion in general rate base is unduly prescriptive. At the heart of this prohibition and the requirement to share benefits with nonparticipating customers, is the concern against cost shifting. The Commission already has authority to review the VRET design for cost shifting and may require, if cross subsidization is identified and not eliminated in the design, sharing of benefits. For example, the GEAR design is such that participating customers pay all costs under COS and an additional amount for the renewable resource.

Q. Please summarize Parties' positions.

A. CUB,[91] PAC,[92] and RNW supported this modification, with RNW noting support only if the CBRs applied.[93] Staff initially supported the change, stating that the proposed modification provides "a more general 'no cost shifting' rule which better applies to all potential utility owned proposals."[94] However, Staff now states that the proposal did not consider "the

[90] PGE/500, pages 25-26.
[91] CUB/200, pages 15-16.
[92] PAC/200, page 3.
[93] RNW/300, page 13.
[94] Staff/300, page 20.

utility's size, access to cheaper capital, and regulated utility status…resulting in an unfair competitive advantage" and thus the proposed language is "insufficient".[95] Staff currently proposes the following (italicized to show Staff's proposed changes): "The regulated utility may own a voluntary renewable energy resource. *When* it does, it must continue to ensure there is no cost shifting to non-participants *and the offering does not create a barrier to the competitive retail market*". NIPPC opposes this modification and advocates to maintain the language as approved.[96]

Q. Do you agree with Staff's proposal?

A. No, for the following reasons:

- Staff and NIPPC employ unrealistic assumptions regarding the impact of utility ownership on the competitive retail market;
- The utility intends to hold a competitive procurement process for the sourcing of a VRET resource; and
- The utility does not have a competitive advantage in the renewable development market.

Q. While utility ownership is already explicitly permitted, Staff's testimony makes several assumptions regarding the impact of utility ownership on the competitive retail market. Please respond.

A. In Staff's theory (not supported with any examples), the utility issues and wins VRET procurements so much that it discourages entities from developing resources to a point where none remain for DA customers. This is a highly unlikely and invalid scenario. First, the

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[95] Staff/400, page 23.
[96] NIPPC/300, page 25.

VRET is constrained by the cap; which as proposed would equal 500 MW and convert to only 150 aMW (see Section II.B., above, and how this compares to the DA cap of 419 aMW). Second, PGE and Oregon utilities are not the only customers for renewable resources in the region. This means that resources will continue to be developed regardless of a VRET outcome. Finally, we have not developed any of our own renewable resources from the project's beginning. Every renewable project we have acquired to date was developed by a third-party, with the project assets being sold to us once the project matured. This suggests that some resource developers are perfectly comfortable selling projects to utilities or other independent power producers (IPPs) and not being long-term owners. This alone would encourage projects to continue to be developed with the incentive of a possible sale to a utility or other IPP later in the project life.

Additionally, it is unclear if Staff is conflating the competitive retail market and the wholesale renewable development market. The only linkage that seems to support the addition of the retail market language is the highly unlikely scenario where VRETs cause renewable development to stop, leaving no resources available for DA customers. This argument contradicts itself because if there is demand for renewables for DA, developers would be there to supply resources.

Q. Are there any additional issues in Staff's arguments?

A. Yes. Staff's proposed language would shift what they state as the Commission's "obligation to ensure that it does not create barriers to the competitive marketplace" onto the utility and then require the utility to prove a negative.[97] It is unclear how a utility would comply with

[97] Staff/400, page 11.

this condition and Staff does not provide any guidance or address compliance in their testimony.

Q. Please discuss NIPPC's assumptions regarding the impact of a utility owning a VRET resource on the competitive retail market.

A. NIPPC refers to Staff's argument in OPUC Docket No. UM 1690 where they state that the utility is "able to absorb the failure of a generation asset (a failed market entry) through means afforded to it by way of its regulated status"[98] and that this ability is a barrier to the competitive retail market. This argument ignores the fact that a regulated Oregon utility must meet the used-and-useful[99] and prudence standards, along with the requirement for VRETs that there be no cost shifting from participants to nonparticipants.[100] Further, IPPs have more opportunities to remarket projects should the originally intended offtake change. They can sell to DA customers, other utilities, or wholesale market participants. In summary, NIPPC's unfounded fear and unsubstantiated assertion does not amount to a barrier to the competitive retail market.

Q. Does NIPPC make any other arguments for how utility ownership can impact the competitive retail market?

A. Yes. NIPPC highlights another argument made by Staff that the utility owning VRET resources "may further inhibit competitiveness due to a utility's horizontal market power"[101] which Staff in their UM 1690 memo said could be conducted through "cross-

[98] NIPPC/300, pages 22-23.
[99] "ORS 757.355 (Costs of property not presently providing utility service excluded from rate base)." Chapter 757. OregonLaws.org. Retrieved from https://www.oregonlaws.org/ors/757.355
[100] 77th Oregon Legislative Assembly. "Oregon House Bill 4126." 2014 Regular Session. Oregon State Legislature. 11 Feb 2014. Retrieved from https://olis.leg.state.or.us/liz/2014R1/Downloads/MeasureDocument/HB4126
[101] NIPPC/300, page 23.

subsidization".[102] As we have noted, and Parties are aware, there are statutory and regulatory requirements against cost-shifting, which prohibits any VRET from using COS assets to subsidize a VRET.

Q. Do you contemplate using a competitive procurement process for the sourcing of a VRET in tranche 2?

A. Yes. As stated earlier, we have always intended to procure resources for the GEAR through a competitive procurement process. Although we have requested a waiver of the CBRs, we have proposed a competitive procurement process that will include third-party owned resources. The waiver of the CBRs will simply reduce time and expense that would otherwise not allow us to meet customer needs at an attractive price. Our proposed competitive process includes Staff oversight to ensure a fair result. The acquisition of the resource will always be subject to a prudence review during ratemaking to ensure the least cost, least risk resource is acquired for participants.

Q. Do you have a competitive advantage in the renewable development market?

A. No. Staff seems to suggest that we have a competitive advantage when it comes to the ability to build renewable resources because of our "size, access to cheaper capital, and regulated utility status."[103] The current ownership profile of regional renewable resources does not provide evidence of any competitive advantage; IPPs own 67% of all solar and wind projects in Oregon and Washington as of the end of 2018.[104] Based on preliminary 2019 data from

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[102] "In addition to natural monopoly advantages and barriers to entry. utility participation in a VRET market may further inhibit competitiveness due to a utility's horizontal market power Horizontal market power is characterized by "a firm's ability to influence price in a single market," which can be conducted through cross-subsidization." Source: Public Utility Commission of Oregon. "Order 15-405." UM 1690. 20 Nov 2015, page 12. Retrieved from https://apps.puc.state.or.us/orders/2015ords/15-405.pdf

[103] Staff/400, page 23.

[104] This calculation was based on Energy Information Administration (EIA) EIA-860 Data – Schedule 3. Source: "Form EIA-860 detailed data with previous form data (EIA-860A/860B)." Analysis & Projections. U.S. Energy Information Administration. 2 Jun 2020. Retrieved from https://www.eia.gov/electricity/data/eia860/

the U.S. Energy Information Administration (EIA), the only wind and solar resources added after 2015 have been 615 MW of IPP-owned resources.[105] These results suggest that IPPs may have the competitive advantage and the recent trend may show a disadvantage towards utility ownership because of factors like structural tax disadvantages (e.g. the requirement for utilities to normalize the impacts of the investment tax credit). Further, many IPPs developing renewable resources are large entities with access to low cost capital. Finally, a utility's regulated status provides no advantage towards delivering competitive renewable projects and suggesting we do without substantiation is not only untrue, but troubling.

Q. Does NIPPC provide evidence that there is a robust renewable development market?

A. Yes. NIPPCs comments that "there are many highly competitive renewable facilities under development by IPPs in the region"[106] and looks forward to those projects being bid into a VRET program to make it successful. It also suggests that the market is robust and unlikely to be impacted negatively by a VRET program. According to EIA, Oregon and Washington had 6,618 MWs of wind and solar resources at year-end 2018 with only 300 MW of Oregon VRET programs approved through the GEAR tranche 1. In summary, the renewable market is robust and unlikely to be impacted even if the VRET program were to expand significantly.

D. Condition 8 (Ensuring No Cost Shifting)

Q. What is the current language of Condition 8 and what is your proposal?

A. The current language, as updated in Order 19-075, reads:

> 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

[105] Id.
[106] NIPPC/300, page 26.

> are not limited to ancillary services and stranded costs of the existing cost of service rate-based system.[107]

We initially proposed the following, which eliminates the last sentence: All direct and indirect costs and risks are borne by the participating VRET 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.[108] This modification recognizes that ancillary services costs and existing assets are funded through the subscribing customer's continued service on COS.

Q. Please summarize Parties' positions.

A. CUB,[109] RNW,[110] and PAC[111] support this modification to Condition 8. NIPPC opposes any change to the condition.[112] Staff proposes the following change (italicized to show Staff's proposed changes):

> 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 verifications by Commission Staff of all utility costs. Cost include but are not limited to ancillary services and *costs of the existing and future cost of service rate-based system.*[113]

Q. How would you characterize Staff's proposed modification?

A. We believe that Staff's proposed language is unclear as written and may have inadvertently left out some of the language from the original condition.

Q. Why do you believe Staff's proposed language is unclear?

[107] Public Utility Commission of Oregon. "Order 19-075". UM 1953. Public Utility Commission of Oregon. 5 Mar 2019, page 3. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-075.pdf
[108] PGE/500, page 26.
[109] CUB/200, page 17.
[110] RNW/300, page 13.
[111] As part of their general comments on the nine conditions. Source: PAC/200, page 1.
[112] NIPPC/300, pages 21-22.
[113] Staff/400, page 25.

A. Staff's definition of cost includes "costs of the existing and future cost of service rate-based system." In its broadest sense, that could capture the entirety of our revenue requirement for all resources—which we do not believe to be Staff's intent. Instead, Staff may be referring to the costs to administer the program. Even with clarification to remove the uncertainty, we believe the language to be duplicative.

Q. Do you agree with Staff's proposed language for Condition 8, with clarification?

A. No. We continue to recommend our streamlined modification as the first sentence of the condition encompasses the full statutory requirement. HB 4126 states: "All costs and benefits associated with a [VRET] shall be borne by the nonresidential customer receiving service under the [VRET]."[114]

Q. Do you agree with Staff's proposal to include language that references the costs of future COS rate-based systems?

A. No. We are concerned that this language could lead to speculation on this future amount, which is not appropriate to charge existing VRET customers for potential future costs.

Q. Are there other interpretations of Staff's language?

A. Yes. The current language includes the term "stranded costs" and so Staff may have meant "all stranded costs of existing and future cost of service rate-based system" would be borne by VRET customers; therefore, we will respond as such.

Q. Please elaborate on the issue of stranded costs.

A. Stranded costs of the existing system should not be borne by VRET customers for reasons previously discussed in PGE Exhibit 600.[115] Staff's recommendation to add "future" to make

[114] 77th Oregon Legislative Assembly. "Oregon House Bill 4126." 2014 Regular Session. Oregon State Legislature. 11 Feb 2014, page 2. Retrieved from https://olis.leg.state.or.us/liz/2014R1/Downloads/MeasureDocument/HB4126
[115] PGE/600, page 25.

Condition 8 "apply to long-term planning" is excessive and impractical to implement. While it appears that Staff wanted to add language that would ensure all VRETs are addressed in long-term planning (for which we agree with regard to the GEAR), the mechanism they propose would require VRET implementers and regulators to burden VRET customers with potential future, and currently unknown, stranded costs.

E. Summary of PGE's Proposed Updates to the Nine Conditions

Q. Please summarize your proposed updates to the Nine Conditions.

A. The complete list of proposed conditions is:[116]

1. Renewable Portfolio Standard (RPS) definitions that must apply to voluntary renewable energy tariffs (VRETs) are for resource type, location, and bundled renewable energy certificates (RECs).
2. VRET options only include bundled REC products. Any RECs associated with serving participants must be retired by or on behalf of the participants.
3. The year that a VRET-eligible resource becomes operational should be no earlier than one year prior to program enrollment. Program enrollment means the date when a customer signs a binding agreement to participate in the program.
4. The VRET program size is limited to 500 MW for PGE and 175 aMW for PAC.
5. VRET design should be sufficiently differentiated from existing direct access programs.
6. Deleted.
7. The regulated utility may own a VRET resource, and when it does, it must continue to ensure there is no cost shifting to non-participants.

[116] This list does not include any modification to Condition 4 to convert PAC's cap.

8. All direct and indirect costs and risks are borne by the participating VRET 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.
9. All VRETs must be made publicly available and subject to review by the Commission to ensure they are fair, just, and reasonable.

Q. Is tranche 2 of the GEAR compliant with the proposed Nine Conditions listed above?

A. Yes.

III. GEAR Tranche 2 Program Design

A. Make the GEAR 500 MW

Q. Please summarize your proposal.

A. For tranche 2, we propose the total GEAR be 500 MW and that this amount be reflected in Condition 4. In addition, we agree with NIPPC[117] to maintain the distinction, consistent with tranche 1, between the CSO and PSO and propose allotting 100 MW to CSO and 100 MW to PSO.

Q. Please explain why you would propose to change the VRET program cap in Condition 4 from being expressed in customer load (aMW) to nameplate capacity of the renewable resource (MW) given that this limits the total for the GEAR?

A. As stated earlier in this proceeding, we recognize that the GEAR will not have unlimited demand.[118] This is because GEAR customers remain on COS, and as our system becomes increasingly decarbonized, they will eventually meet their sustainability targets with their base COS resource mix.[119] In this Phase 2, we seek 200 MW for tranche 2 and will return to the Commission should there be customer demand to support additional tranches. This guarantees the Commission and stakeholders the opportunity to evaluate future GEAR tranches. This evaluation could include the level of impact to long-term resource planning[120] or impacts to the competitive retail market.

Q. What are Parties positions?

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[117] NIPPC/300, pages 30-31.
[118] PGE/600, page 14.
[119] PGE/500, page 14.
[120] PGE/600, page 45.

A. RNW[121] supports an increase and Walmart does not oppose.[122] CUB[123] and Staff argue that there has not been enough experience gained to launch another tranche. Specifically, Staff states more information is needed to determine if a fixed credit methodology is desirable by customers;[124] therefore, Staff proposes the Commission determine a reasonable size for the PSO and allow CSO-eligible customers to apply on a case-by-case basis.[125] NIPPC states that they do not oppose tranche 2 if we comply with the Nine Conditions, as currently adopted.[126]

Q. If, as CUB and Staff state, there is not enough operational experience gained to expand the GEAR, when would you gain this experience?

A. To be completely informed by the results and performance of tranche 1 could require waiting up to 15 years, the term of the resource and customer agreement. This timeline is unacceptable to customers[127] and is not responsive to Oregon's decarbonization direction most recently addressed in the Governor's Executive Order No. 20-04.[128] We have described how the program works, how the credits will be calculated, how the program interacts with long-term planning, and importantly, how COS customers are protected from cost shifting.[129] As we have designed the program, participating customers continue to contribute to resource adequacy and legislative mandates, while adding additional renewable generation. Developing and operating renewable resources is also not new. Finally, we note that the Commission specifically deemed the GEAR a "program", rather than a "pilot", suggesting

[121] RNW/400, pages 4 and 8.
[122] Walmart/400, page 3.
[123] CUB/200, page 14.
[124] Staff/400, page 31.
[125] Ibid, page 33.
[126] NIPPC/300, page 30.
[127] PGE/600, page 11.
[128] Brown, Kate. "Executive Order No. 20-04." Office of the Governor. State of Oregon. 10 Mar 2020, pages 7-9. Retrieved from https://drive.google.com/file/d/16islO3GTqxVihqhhIcjGYH4Mrw3zNNXw/view
[129] PGE/600, page 12.

that we have demonstrated the offering's value and did not need to approach future tranches in a pilot-like, learnings-focused way.[130] In summary, there is no reason to delay tranche 2 based on the need for more operational experience.

Q. Do you agree with Staff's alternative proposal to cap the PSO and allow CSO expansion through customer application to the OPUC on a case-by-case basis?

A. No. We prefer having some identified megawatts for both options to facilitate planning and allow greater flexibility in meeting customers' timing and demand to take service under the GEAR. A case-by-case process would add administrative and regulatory burdens on customers, the Company, Staff, and the Commission; therefore, we believe this process should be reserved for incremental need, e.g., where PGE and a customer seek a waiver of the cap from the Commission (as discussed in more detail in the Post Phase 2 Process in Section IV.D, below).

Q. If the Commission determines that the CSO process should involve customers petitioning the Commission to participate, do you have a recommended process?

A. Yes. We propose clear direction on what is required in a petition, how it should be filed, the role of the customer and PGE, Staff review, and consistent with the process discussed in Section IV.D, below, within 90 days a presentation of Staff's recommendation for Commission action at a public meeting. We will retain the responsibility and right to review and approve the terms and conditions of the Power Purchase Agreement (PPA), confirm conformance to our minimum terms and conditions, and evaluate the PPA risk to shareholders and other customers. We suggest that the CSO filing with the Commission include:

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[130] Public Utility Commission of Oregon. "Order 19-075". UM 1953. Public Utility Commission of Oregon. 5 Mar 2019, page 4. Retrieved from https://apps.puc.state.or.us/orders/2019ords/19-075.pdf

- A customer Letter of Intent that contains the following:
    - Participation level (MW of resource or MWh of demand),
    - Commitment term (must equal PPA term), and
    - Whether the customer will bring a resource or if they want PGE to conduct a competitive procurement on their behalf that could include third-party and utility-owned resources.
- Information to enable the Commission to determine impact to COS customers; and
- Potential benefits for the system.

The applications would reflect sensitivity to customer desires for confidentiality.

Q. NIPPC states that an expansion on the VRET cap without also expanding DA would "improperly inhibit competition and further entrench PGE's monopoly status."[131] Do you agree?

A. No. NIPPC's argument reveals that it does not understand that the GEAR is based on nameplate capacity of the resource while LTDA and NLDA are based on participating customer load. As we stated earlier, our proposal to modify Condition 4 makes it significantly lower than our LTDA and NLDA caps (approximately 150 aMW for the GEAR, includes tranche 1 and 2, compared to 419 aMW for DA). We doubt that NIPPC would agree to either decreasing the DA cap to match the GEAR or increase the GEAR cap to match DA if mirroring is required. If the GEAR cap were expressed in similar terms to the 419 aMW combined cap for LTDA and NLDA, using the estimated capacity factor for the tranche 1 solar resource, the GEAR cap would be approximately 1,000 MW.

[131] NIPPC/300, page 31.

B. Customer Size Requirements

Q. Please summarize Parties' positions.

A. In our initial proposal, we recommended that the CSO be limited to customers larger than 10 aMW to limit the number of CSO applications to manage and limit administrative costs.[132] RNW supported this proposal but expressed concerns in the long run if demand for the CSO grows.[133] Walmart argues that for the CSO, the threshold should be set at 5 aMW.[134] Staff recommends that customers below 10 aMW be allowed to petition the Commission for approval in the CSO on a case-by-case basis.[135] We supported Staff's proposal in reply testimony.

Q. Do you still agree with Staff?

A. Yes. We continue to support Staff's proposal as this will give us the ability to control administrative costs[136] and resource costs[137] while also providing an opportunity to customers (i.e. 5 aMW) in the CSO who may have the experience, ability, opportunity, and specific interest in finding their own resource (PPA).

C. Risk Adjustment Fee

Q. Please summarize Parties' positions.

A. We initially proposed four risk categories, which could result in an adder to the VRET price: undersubscription,[138] customer load variability,[139] variable resource,[140] and PPA.[141] PAC

[132] PGE/500, page 10.
[133] RNW/300, page 5.
[134] Walmart/300, page 6.
[135] Staff/400, page 46.
[136] PGE/500, page 10.
[137] PGE/600, page 35.
[138] PGE/500, pages 13-14.
[139] Ibid, page 14.
[140] Ibid, pages 14-15.
[141] Ibid, page 15.

expressed support for the quantification and compensation of risk to shareholders.[142] However, we agree with Staff to explore risk adjustment COS PPAs in another docket. In addition, per Staff request,[143] we provided more detail regarding these risks in reply testimony and proposed the adjustment be "no more than 10% for comprehensive program- and PPA-based risks."[144] Staff states that these risks (other than PPA) "may be reasonable if quantified in a sufficient manner"[145] and so they recommend the Commission not allow us to increase the risk adjustment fee beyond what was already approved in Phase 1 until a GEAR tariff filing contains a more detailed methodology for Staff and the Commission to review.[146]

RNW supports a methodology that accounts for both potential costs and benefits.[147] Walmart does not support this proposal and states that if the Commission determines a fee is warranted, then we should identify each risk and the methodology.[148] NIPPC does not support it asserting that our rate of return already includes a premium to reflect business risk. NIPPC then opines that we could double recover with a risk adjustment premium and earn a rate of return on the same asset.[149]

Q. Do you agree with Staff's proposal?

A. In part. A risk adjustment fee is necessary to fully insulate non-participating COS customers from, and fairly compensate shareholders for, the risk associated with the GEAR.

In addition, a flexible risk adjustment fee is still the best outcome for GEAR participants, COS customers, and shareholders, in that it can be adjusted for resource specific risks and

142 PAC/100, page 1.
143 Staff/400, pages 34-35.
144 PGE/600, page 33.
145 Staff/400, page 36.
146 Ibid, pages 31.
147 RNW/300, page 7.
148 Walmart/400, page 5.
149 NIPPC/300, page 28.

risks that may change over time. It is tempting to believe that current assumptions on program cost, resource cost, REC cost, and credit values remain constant or that only current values should be considered for potential risks, but that does not explore the range of potential risks shareholders may experience over the program's term. We appreciate stakeholders desire to learn more about the methodology; therefore, PGE Exhibit 802 provides simple scenarios that show how wide the fee range can be depending on assumptions like program cost and assumed replacement REC cost. The analysis considered costs that our shareholders would have to receive from customers remaining on the program to be made whole. While not completely analogous to what the risk premium may be, which should include some acknowledgement of the risk weighted possible outcomes, it does show a range of possible outcomes that will help in understanding why we proposed an adjustable mechanism.

Q. Please summarize PGE Exhibit 802.

A. The first scenario examines what happens if everything goes according to plan. As one might expect, this results in no required payment from our shareholders and would be one bookend in terms of potential risks.[150]

The second scenario considers the opposite extreme where all risks of the program are realized; the program participation is diminished, resulting in very few participants paying for the costs of the program, and the resource doesn't produce. While unlikely, this bookend scenario produces a result where the payment would have to be 3,010% of the PPA price to ensure no loss for our shareholders.[151]

[150] PGE/802, page 1.
[151] Ibid, page 2.

A third scenario examines the risk that the resource under-generates compared to forecast and we must purchase similar RECs to fulfill our customer obligations. Assuming a decrease in generation of 20%, the premium collected from customers would have to be approximately 4% of the PPA price.[152]

Finally, evaluating a scenario where the program is 20% undersubscribed due to an unexpected event (e.g. customer bankruptcy) and load is only 90% of forecast (a result that may be conservative given current events), the premium collected from customers would have to be 5% of a $40/MWh PPA price.[153]

If the Commission is unwilling to approve a flexible credit value, we would support establishing a reasonable value within the range of possible risk.

Q. Do you have a proposal?

A. Yes. Acknowledging that neither extreme result is appropriate, we propose to use the lesser of the most recently approved cost of debt or cost of equity, but in no instance greater than 10% as a percentage of the PPA price for the risk adjustment fee. We propose these values for the following reasons:

- The cost of debt and equity are generally accepted as fair risk compensation metrics. The cost of debt is what a lender will charge for the risk on a loan and the cost of equity is what shareholders require for risk compensation.
- Cost of debt and equity are updated to reflect macro level changes to risk compensation generally, and therefore, are unlikely to become dated.

[152] Ibid, page 3.
[153] Ibid, page 4.

- Making the risk adjustment fee equal a percentage of the PPA price serves as a proxy for both energy prices and potential REC prices. This is because as both of those increase or decrease, you would expect to see a similar increase or decrease in power prices.

D. Calculation of the Energy and Capacity Credits

Q. Please summarize your proposal.

A. We propose the continued use of our credit methodology approved in Phase 1, using fixed credits where the energy and capacity credits will be calculated at the time the resource is procured and cannot result in negative credits.[154]

Q. Do Parties' agree with your proposal?

A. Staff continues to support this methodology;[155] however, CUB,[156] Walmart,[157] and RNW[158] prefer a floating credit methodology that would allow VRET participants to achieve net bill savings compared to COS rates. CUB proposes the use of Staff's floating credit methodology from Phase 1, which is based on the actual power cost impact for COS customers using PGE's MONET power cost forecasting model.[159] CUB supports our using the RECAP model for the capacity credit,[160] which Staff then supported as it "better reflects the actual capacity cost that is avoided due to the VRET program."[161] RNW proposes a Commission placeholder decision on capacity credits pending the conclusion of OPUC Docket No. UM 2011 (General

[154] PGE/500, page 8.
[155] Staff/400, pages 28-29.
[156] CUB/200, pages 8-9.
[157] Walmart/400, pages 1-2.
[158] RNW/300, page 4.
[159] CUB/200, pages 8-9.
[160] Ibid, page 9.
[161] Staff/400, pages 29-30.

Capacity Investigation).[162] In addition, for the CSO in tranche 2, Walmart supports AWEC's proposal of a marginal cost-based credit from Phase 1.[163]

Q. Why do you not agree that a floating credit methodology should be used?

A. Floating credits mean energy and/or capacity credits are recalculated annually for just the forward year. As stated in PGE Exhibit 500 and earlier in this testimony, we did not design the GEAR to be a bill discount program; it was designed to be a program to drive additionality of renewable generation. Consistent with the Commission's guidance in Phase 1, we would consider allowing net bill savings for the CSO, but only on a case-by-case basis with Commission approval.[164]

In addition, with a floating credit, the GEAR would not maintain a fixed price for subscribers. It could allow customers to potentially have net bill savings, which is a concern of Staff's regarding the competitive market.[165] Conversely, it could result in higher costs than those initially contracted for the resource.

Q. Do you still propose to use the RECAP model to determine capacity contributions?

A. We propose to use the loss of load probability model used in the most recently filed IRP or IRP Update at the time of the capacity credit determination to determine capacity contributions. The most recently filed IRP or IRP Update is the 2019 IRP, which used the RECAP model to determine capacity needs and capacity contributions. We are currently exploring alternative loss of load modeling methodologies within the IRP process. If a new loss of load model is adopted within a future IRP or IRP Update prior to the capacity credit determination, we would plan to use that model for consistency with the IRP.

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[162] RNW/300, page 18.
[163] Walmart/400, page 2.
[164] PGE/500, pages 8-9.
[165] Staff/400, page 29.

IV. GEAR Tranche 2 Resource Procurement and Long-Term Planning

A. Utility Ownership of GEAR Resources

Q. Please discuss your intent to own a GEAR resource in tranche 2.

A. We confirm that in our initial testimony we stated that ownership is an option for tranche 2 of the GEAR.[166] We also stated that we had no plans to include a utility-owned option at that time. We understand now that the wording of that sentence may have caused some confusion for some stakeholders. Therefore, we provide a clearer articulation of our position (which remains true today) – we do not currently have a specific resource identified for participation in the GEAR tranche 2 but expect utility ownership to be an option in this tranche.

Q. What are you requesting in Phase 2 regarding ownership of a GEAR resource?

A. For this proceeding, we are only requesting that the Commission approve our proposed amendment to Condition 7 and specify additional considerations regarding utility ownership, if any.

Q. Are Parties supportive of you owning a GEAR resource?

A. Some Parties are, in part. RNW supports keeping the utility ownership option open as long as the CBRs apply.[167] CUB believes it is reasonable to allow a utility to own as long as no cost shifting occurs, but notes concerns regarding additional risks to non-participants; therefore, they recommend "enhance[d] scrutiny at the Commission" to ensure no cost-shifting occurs.[168] Staff has stated concerns and proposes a review process for ownership applications. NIPPC opposes utility ownership of a VRET resource stating that "allowing a

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[166] PGE/500, page 11.
[167] RNW/400, pages 10-11.
[168] CUB/200, page 16.

utility to own and include a VRET resource in rate base is not in the public interest and does not add any benefit to the program".[169]

Q. Do you agree with CUB?

A. Yes. In addition, we note that this additional scrutiny can occur during a prudence review.[170]

Q. Please summarize Staff's position.

A. Staff has stated that they are not opposed to utility ownership of a VRET resource, and notes that it is expressly allowed under the currently approved Condition 7;[171] however, Staff stated that they do not believe a decision on ownership should be made until "the details are laid bare".[172] Consequently, Staff proposes that when we determine the appropriate ownership model, that a thorough review of the utility ownership proposal is warranted prior to us offering it to customers. In addition, Staff does not object to including the appropriateness of our proposal as an issue during a general rate case (GRC) or other filing. If this is prior to a GRC, Staff proposes that an application that includes evidentiary support for the adherence to the Nine Conditions be filed.[173]

Q. Do you agree with Staff that further detail is needed prior to arriving at a decision on PGE owning a GEAR resource?

A. We are unclear as to what further details Staff is referring. First, we have provided enough conceptual detail for the Commission and Parties to understand the key components of a structure we would propose when including a utility-owned option.[174] We received some feedback and intend to use it to narrow the scope of possibilities. Second, any ownership

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[169] NIPPC/300, page 4.
[170] PGE/700, page 17.
[171] Staff/400, page 38.
[172] Ibid, page 39.
[173] Ibid, pages 40.
[174] PGE/600, pages 28-31.

option that we eventually propose will, by its very nature, require detailed regulatory scrutiny and Commission approval. Staff's concerns regarding the potential for inadequate review of a PGE-ownership option appear to be misplaced. As indicated above, we are requesting approval of our modifications to Condition 7 and inquiring of the Commission if there are any additional considerations regarding utility ownership.

Q. Do you agree with Staff's proposed ownership application process?

A. We are not certain what additional process is necessary given the existing regulatory requirements. More specifically, we would expect that any application to include a utility-owned resource in rate base will require a full prudence review including support for the adherence to established Commission criteria. We would also expect that any filing to include a utility-owned resource via an affiliated interest filing will be required to meet the same level of scrutiny, as well as seek approval of all agreements between PGE and the affiliate. Plus, as we discuss below, any owned resource we might propose will also be subject to the same competitive procurement process. In short, we believe that Staff and the Commission already have the regulatory tools and processes necessary to ensure timely compliance with Commission-approved criteria. What we seek to avoid are duplicate proceedings – first, a full regulatory process to consider a proposed ownership structure, and second having to repeat the process in a ratemaking proceeding because in the first instance, the Commission would not grant pre-approval of the proposal.

Q. Did Staff have any further comments?

A. Yes. Staff stated that they did not support both the waiver of the CBR process and utility ownership of a VRET resource as it could "effectively turn into a special contract for the CSO customer, with minimal oversight from the Commission".[175] To address this, Staff proposes that, "If and when the Company elects to offer a utility owned resource as part of a CSO, the currently approved CBR process for PSO offerings with utility ownership, modified or otherwise, must be used to provide the customer with all the necessary information on which it can then make its selection."[176]

Q. Do you agree?

A. In general, we agree with Staff's proposal. We discuss our position on the applicability of the CBRs to tranche 2 in the next section.

B. Competitive Bidding Rules (CBRs)

Q. Please summarize Parties' positions.

A. We initially requested that the CBRs be waived for the GEAR tranche 2.[177] PAC supports the CBRs being waived for VRET programs.[178] RNW asserts that the CBRs should apply when utility-owned resources are involved in the procurement process.[179] NIPPC advocates that the CBRs may be waived in a PPA-only solicitation, but that a waiver would be inappropriate if the utility proposes to own the resource.[180]

Staff recommends that the Commission adopt a set of principles[181] for us to propose an "'RFP-light' for review and approval in compliance with the Commission's Order."[182] In addition, Staff recommends that we be required to offer this same RFP process for the CSO and that the resource selection reside with the customer. According to Staff, if we elect to

[175] Staff/400, pages 41.
[176] Ibid, page 45.
[177] PGE/500, page 30.
[178] PAC/100, page 5.
[179] RNW/300, page 6.
[180] NIPPC/300, page 30.
[181] Staff/400, pages 43.
[182] Ibid, pages 44.

offer a utility-owned resource as part of a CSO, the currently approved CBR process for PSO offerings with utility ownership, modified or otherwise, must be used.[183]

Q. Do you agree with Staff's proposal?

A. We continue to believe that a waiver of the CBRs can be appropriate for reasons both PGE[184] and PAC[185] have discussed; however, we also recognize stakeholder concerns with the waiver when utility ownership is included, a feature important to us. Although the risks that we have expressed in prior testimony still exist,[186] we appreciate Staff's proposal but would require it to be expanded to include a utility-owned resource offering as well. If applicable to all procurements, regardless of whether we include a utility-owned resource, we would be amenable to 1) not seeking a waiver, and 2) employing a modified and streamlined competitive bidding process.

Q. Have other Parties expressed support of this in prior testimony?

A. To some extent. RNW supports utility ownership if the CBRs apply to ensure competitive procurement as there may be a perception of potential utility bias.[187] RNW also states that a streamlined competitive bidding process may be appropriate if utility ownership is not an option.[188]

Q. Please provide more detail on what a modified and streamlined competitive bidding process could look like.

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[183] Ibid, pages 45.
[184] PGE/500, page 30.
[185] PAC/100, page 5.
[186] PGE/600, page 31.
[187] RNW/400, page 12.
[188] Id.

A. While we appreciate Staff outlining principles that should apply,[189] the process these principles would require is unlikely to result in a procurement effort that materially reduces the time and cost from a full CBR procurement. Instead we propose that the modified and streamlined competitive bidding process would use the template of PGE's prior Commission-acknowledged RFP as a starting point and make changes where appropriate; this would significantly reduce the time and cost of its implementation without changing the ability for an unbiased selection process. PGE Exhibit 801 provides further detail on the modified process (in comparison to a full-RFP process).

C. Integrated Resource Plan (IRP) Interactions

Q. Please summarize your proposal and Parties' positions.

A. We proposed to include sensitivity analysis, in our base case analysis, in each IRP. Specifically, this would include VRET participation up to the currently approved program cap and currently subscribed VRET load.[190] Although RNW[191] and Staff generally supported this approach, Staff added one clarification that we also include "potential and expected growth of VRET products in the future as well as the total impact of all current VRET products on the utility's IRP planning process."[192]

Q. Do you agree with Staff's proposal?

A. We agree that it is appropriate to account for current VRET products within the IRP and that the IRP provides an opportunity to understand how potential growth of VRET products could impact future resource needs; however, we do not agree with Staff that we should quantify expected growth of VRET products within the IRP.

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[189] Staff/300, page 43.
[190] PGE/500, page 35.
[191] RNW/400, pages 13-14.
[192] Staff/400, page 47.

Q. Why is it important to differentiate between potential and expected growth of VRET products in IRP treatment?

A. Within the IRP, the determination of an expected outcome requires the ability to quantify the likelihood of various outcomes relative to one another. Such a quantitative determination would be highly speculative for future VRET programs; however, we agree that the potential for future VRET products could be an important consideration within the IRP in the evaluation of risk and/or contextualizing an Action Plan. For this reason, we support the consideration of potential growth in VRET products within the IRP, but not the determination of expected growth in VRET products within the IRP.

D. Post Phase 2 Process

Q. Please summarize your proposal and Parties' replies.

A. Although tranche 2 is calculated to serve existing and known customer demand, we would like to establish the process for future increases in the nameplate capacity of the GEAR for future tranche offerings. The process would likely start with a tariff filing, proposing an increase in the cap. We proposed a 60-day review process that would result in a Commission determination. RNW supports this proposal[193] and Walmart does not oppose.[194] Staff prefers a 90-day timeframe to allow time for Parties to work towards a final recommendation to the Commission at a subsequent public meeting. In addition, Staff notes it is reasonable to allow us to request a simple 'approve or deny' Commission decision, but the Commission may need more time to investigate the filing.[195]

Q. Do you agree with Staff's proposal?

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[193] RNW/400, page 14.
[194] Walmart/400, page 3.
[195] Staff/400, pages 49-50.

A. Yes. We appreciate Staff's willingness to have an accelerated process and find a 90-day timeline reasonable.

Q. Do you agree with NIPPC that there should be a tandem expedited process for expansion of the caps on competing products offered through DA?[196]

A. No. Even if the Commission applies strict mirroring in Condition 6, which seems unlikely given the flexible approach in tranche 1, DA program caps are in scope in the UM 2024 investigation and we recommend that any changes to the DA cap result from that investigation's conclusion.

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[196] NIPPC/300, pages 31-32.

V. Summary

Q. Please summarize your request of the Commission.

A. Considering Executive Order No. 20-04 and Oregon's commitment to accelerate decarbonization, and in continuing support of what our customers want, we request the Commission to:

- Adopt the proposed updates to the Commission's Nine Conditions, as described in Section II.E., above;
- Approve the GEAR as a total of 500 MW;
- Approve the CSO minimum customer size requirement at 10 aMW, consistent with tranche 1;
- Acknowledge that the breadth of risk, beyond that discussed in our Phase 1 testimony, brought to PGE by the GEAR, should be borne by subscribers via the risk adjustment fee;
- Approve the continued application of the method from tranche 1 to tranche 2 for the calculation of the energy and capacity credits;
- Grant a waiver of the CBRs for the GEAR tranche 2;
- Approve our proposal that the interim transmission solution outlined in PGE's 2019 IRP Addendum on August 30, 2019 be applied to VRET procurement;
- Affirm that our approach to addressing the GEAR interactions within the IRP is reasonable; and
- Approve the 90-day process for the GEAR, after tranche 2 is full, to offer subsequent tranches.

Q. Please summarize your alternate requests.

A. We propose the following in the event that the Commission does not approve three of our primary proposals listed above:

- Should the Commission not waive the CBRs, allow us to conduct a modified RFP process, discussed in PGE Exhibit 801;
- Should the tranche 2 size of 200 MW not be approved, determine a reasonable PSO size and establish a process for determining case-by-case CSO applications, discussed in Section III.A, above; and
- Should the Commission choose to keep some version of Condition 6, acknowledge, as it did in Phase 1 of this docket, that Condition 6 does not apply to COS riders (discussed in Section II.B of this testimony) and that a strict application of each of the Nine Conditions to the GEAR is not required.

VI. Qualifications

Q. Mr. Faist, please describe your educational background and experience.

A. I received a Bachelor of Business Administration in Accountancy from the University of Notre Dame in 2006 and a Master of Science in Accountancy from the University of Notre Dame in 2007. I have been with PGE since 2013 where I started in the Tax department and have been a member of the Structuring and Origination department since 2016. Prior to working at PGE, I worked at both KPMG and Conway, Inc.

Q. Does this conclude your testimony?

A. Yes.

List of Exhibits

PGE Exhibit	Description
801	GEAR Tranche 2 Modified RFP Process
802	Risk Adjustment Scenarios

PGE Exhibit 801 – GEAR Tranche 2 Modified RFP Process Proposal

PGE provides more detail on what a modified and streamlined competitive bidding process could look like for tranche 2 of the GEAR. Below is a comparison of the current requirements and PGE's proposal.

Request for Proposal Requirements[1]	**Modified Request for Proposal Process**
Independent Evaluator The OPUC approves the appointment of the independent, third-party evaluator (IE), to help ensure the RFP is conducted in accordance with the OPUC Competitive Bidding Guidelines, and that all bids are evaluated consistently and impartially. The IE will: ▪ Consult with PGE in preparing the RFP and submit its assessment of the final draft RFP to the OPUC when PGE files for RFP approval. ▪ Work with PGE and the OPUC Staff to finalize scoring and evaluation criteria, including providing "mock bids" to test the integrity of the evaluation models. ▪ Independently assess the reasonableness of the score(s) for PGE's Benchmark Resource(s). ▪ Evaluate the unique risks and advantages associated with the Benchmark Resource(s). ▪ Independently score all or a sample of the bids to determine whether the selections for the initial and final short-lists are consistent with the bid evaluation criteria. ▪ Compare the results of the IE's scoring with PGE's scoring and work with PGE to reconcile and resolve scoring differences, if any. ▪ Prepare a Closing Report for the OPUC after PGE has selected the final short-list. ▪ In its Closing Report, provide its assessment of all aspects of the solicitation process and the IE's involvement, including detailed bid scoring and evaluation results, to PGE, non-bidding parties and the OPUC subject to the terms of the Protective Order.	**Independent Evaluator** Same IE from most recent RFP is engaged for GEAR procurement and: • IE works with PGE and the OPUC staff to finalize scoring and evaluation criteria. OR • PGE uses scoring and evaluation criteria from its most recently completed RFP. • IE independently score all or a sample of the bids to determine whether the selections for the initial and final short-lists are consistent with the bid evaluation criteria. • IE prepares a Closing Report for the OPUC after PGE has selected the final short-list.

[1] Acknowledged by the Commission in PGE's last RFP (cite to commission order)

Typical RFP Schedule

- PGE provides draft RFP to IE (approximately three weeks before next item) (Step 1)
- PGE provides draft RFP to all interested parties (3-4 weeks after step 1) (Step 2)
- Stakeholder and Bidder pre-RFP workshops (approximately 2 weeks after Step 2) (Step 3)
- PGE submits final draft RFP to OPUC for approval (approximately 1 week after Step 3) (Step 4)
- IE submits assessment of the final draft RFP to OPUC (approximately 2 weeks after Step 4) (Step 5)
- Parties and Staff submit comments of final draft RFP to OPUC (approximately 2 weeks after Step 5) (Step 6)
- PGE submits reply comments to OPUC (approximately 2 weeks after Step 6) (Step 7)
- Technical Specifications for PGE sites available (approximately 7 weeks after Step 7) (Step 8)
- IE submits assessment of PGE's Technical Specifications to OPUC (approximately 2 weeks after Step 8) (Step 9)
- Parties submit comments on PGE's Technical Specifications to OPUC (approximately 2 weeks after Step 8) (Step 10)
- PGE submits reply comments to OPUC and revises RFP documents (if necessary) (approximately 1 week after Step 9) (Step 11)
- Staff Report due to OPUC (approximately 2 weeks after Step 10) (Step 12)
- OPUC to render opinion on PGE draft RFP (tentative) (approximately 1 week after Step 12) (Step13)
- PGE issues RFP (approximately 1 week after Step 12) (Step 14)
- PGE Benchmark Bids (self-build submittal) due. (approximately 8 weeks after step 12*) (Step 15)
- Benchmark scores due (approximately 1 week after step 15*) (Step 16)
- All other RFP bids due. (approximately 1 week after step 15) (Step 17)

Proposed GEAR RFP Schedule

- PGE provides RFP design from its last RFP to IE and all parties that participated in most recent renewable procurement (Step 1)
- All RFP bids due. (approximately 4 weeks after Step 1) (Step 2)
- PGE identifies initial short list. (approximately 4 weeks after Step 2) (Step 3)
- PGE selects final short list. (approximately 2 weeks after Step 3) (Step 4)
- IE issues closing report to OPUC. (approximately 2 weeks after Step 4**) (Step 5)
- Commission acknowledgment of short list (approximately 1 week after Step 5) (Step 6)

▪ PGE identifies initial short list. (approximately 12 weeks after step 17**) (Step 18) ▪ PGE selects final short list. (approximately 3 weeks after step 18**) (Step 19) ▪ IE issues final closing report to OPUC. (approximately 3 weeks after step 19**) (Step 20) *Note –* **These dates are contingent on OPUC acknowledgment with no requirements for significant changes to the filed draft RFP.* ***These dates are subject to change depending on the quantity and complexity of bids received.* RFPs typically include sites for Bidders interested in bidding new build resources, and bidder workshops.	

Scenario 1

Resource Size (MW)	100
NCF	0.3
% Actual Gen	100%
REC Price	7.00
PPA Price	40.00
Program Cost	3
% Subscribed	100%
% Actual Load	100%

Year	Forecasted Generation	Actual Generation	Difference	Replacement REC Cost	Generation Risk Premium	Forecasted Load	Actual Load	Incremental Program Cost	Payment to PGE	Difference	Load Required Risk Premium	Total Required Risk Premium	% of PPA Price
1	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
2	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
3	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
4	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
5	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
6	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
7	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
8	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
9	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
10	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
11	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
12	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
13	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
14	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
15	262,800	262,800	-	-	-	262,800	262,800	788,400	788,400	-	-	-	0%
Total	3,942,000	3,942,000	-	-		3,942,000	3,942,000	11,826,000	11,826,000	-			

Scenario 2

Resource Size (MW)	100
NCF	0.3
% Actual Gen	0%
REC Price	7.00
PPA Price	40.00
Program Cost	3
% Subscribed	5%
% Actual Load	5%

Year	Forecasted Generation	Actual Generation	Difference	Replacement REC Cost	Generation Risk Premium	Forecasted Load	Actual Load	Incremental Program Cost	Payment to PGE	Difference	Load Required Risk Premium	Total Required Risk Premium	% of PPA Price
1	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
2	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
3	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
4	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
5	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
6	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
7	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
8	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
9	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
10	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
11	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
12	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
13	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
14	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
15	262,800	-	657	4,599	7.00	262,800	657	788,400	1,971	786,429	1,197.00	1,204.00	3010%
Total	3,942,000	-	9,855	68,985		3,942,000	9,855	11,826,000	29,565	11,796,435			

Scenario 3

Resource Size (MW)	100
NCF	0.3
% Actual Gen	80%
REC Price	7.00
PPA Price	40.00
Program Cost	3
% Subscribed	100%
% Actual Load	100%

Year	Forecasted Generation	Actual Generation	Difference	Replacement REC Cost	Generation Risk Premium	Forecasted Load	Actual Load	Incremental Program Cost	Payment to PGE	Difference	Load Required Risk Premium	Total Required Risk Premium	% of PPA Price
1	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
2	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
3	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
4	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
5	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
6	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
7	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
8	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
9	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
10	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
11	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
12	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
13	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
14	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
15	262,800	210,240	52,560	367,920	1.40	262,800	262,800	788,400	788,400	-	-	1.40	4%
Total	3,942,000	3,153,600	788,400	5,518,800		3,942,000	3,942,000	11,826,000	11,826,000	-			

Scenario 4

Resource Size (MW)	100
NCF	0.3
% Actual Gen	100%
REC Price	7.00
PPA Price	40.00
Program Cost	5
% Subscribed	80%
% Actual Load	90%

Year	Forecasted Generation	Actual Generation	Difference	Replacement REC Cost	Generation Risk Premium	Forecasted Load	Actual Load	Incremental Program Cost	Payment to PGE	Difference	Load Required Risk Premium	Total Required Risk Premium	% of PPA Price
1	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
2	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
3	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
4	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
5	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
6	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
7	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
8	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
9	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
10	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
11	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
12	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
13	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
14	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
15	262,800	262,800	-	-	-	262,800	189,216	1,314,000	946,080	367,920	1.94	1.94	5%
Total	3,942,000	3,942,000	-	-		3,942,000	2,838,240	19,710,000	14,191,200	5,518,800			