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VIA ELECTRONIC FILING
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Public Utility Commission of Oregon
201 High Street S.E., Suite 100
Salem, OR 97308-1088

Attn: Filing Center

RE: UM 2000 – PGE's Response to Stakeholder Questions

Portland General Electric Company (PGE) respectfully submits these responses to stakeholder questions issued by the Public Utility Commission of Oregon (Commission) Staff on March 15, 2019. PGE understands Staff will use these responses to develop a comprehensive list of issues as part of the investigation scope and facilitate discussion at the upcoming public workshop scheduled for April 5, 2019.

With certain proposals discussed further in these responses, PGE reserves the right to propose different approaches at a later time or in response to positions presented by stakeholders.

PGE's responses to Set A (directed at the utilities) and Set B (directed at all stakeholders) are provided below.

Set A

Question #1:

Please provide a high-level description of modeling used to set avoided cost prices, including:

a. A description of variables included
b. Modeling methodology including software used

Response:

Per Commission orders, PGE's current avoided cost pricing methodology incorporates two distinct value streams:

1. Energy value based on forward market curves, correlating to PGE's sufficiency period; and
2. Fully allocated costs of the proxy resource, including capital and operating costs, correlating to PGE's deficiency period.

The methodology and variables included in setting avoided costs prices are described in detail below.

Sufficiency Market Curves

During the sufficiency period, avoided cost pricing is based on the cost of incremental market purchases of energy, which is forecast using PGE's forward Mid-Columbia (Mid-C) trading curves. (PGE's forward Mid-C trading curves are also utilized in models calculating transition adjustments applicable to direct access programs, projected Net Variable Power Costs (NVPC) in General Rate Case (GRC) and Annual Update Tariff (AUT) filings, PGE's Green Tariff, and Resource Value of Solar.)

Mid-C pricing is increased to reflect the cost of one leg of BPA transmission, adjusted for inflation and line losses, so that PGE's avoided cost pricing reflects energy delivered to PGE's system. PGE's avoided cost prices include a single leg of BPA transmission because PGE's generic proxy resources are off-system and located in BPA's balancing authority.

Deficiency Avoided Resource Cost

During the deficiency period, PGE's avoided cost pricing reflects the fully allocated cost of a generating resource—the proxy resource. Ideally, PGE's proxy resource would represent the most cost-effective means for the Company to generate or otherwise acquire energy in order to ensure that customers remain indifferent to the purchase of QF generation. The renewable and non-renewable avoided cost pricing streams each use a single, distinct proxy resource.

In PGE's March 2019 compliance filing ordered by the Commission,[1] the proxy renewable resource is an off-system generic wind resource located in the Columbia Gorge, BPA's balancing authority area, and the proxy non-renewable resource is an off-system combined cycle thermal plant also located in BPA's balancing authority area. With regard to the BPA-PGE interchange for off-system deliveries, there is sufficient capacity at this interchange to accept additional deliveries. In contrast, PGE's alternative off-system delivery point at the interface with PACW is fully subscribed and cannot accept additional deliveries without significant capital upgrades.

PGE calculates avoided cost prices during the deficiency period as follows:

i. PGE calculates a total resource cost for the proxy resource using capital and operating costs and characteristics from the Supply Side Cost Study prepared for PGE's Integrated Resource Plan (IRP). For the March 2019 filing, a few select inputs were updated using information from PGE's draft 2019 IRP, at the Commission's direction.[2] Prior to the March 2019 filing, the inputs utilized all corresponded to PGE's acknowledged 2016 IRP Update. The total resource cost also includes BPA transmission and wind integration costs.

   Once calculated, the total resource cost is translated into a cost per MWh of generation (generating hours are estimated by the Supply Side Cost Study) and grossed up for line losses to reflect MWh delivered to PGE's system.

[1] Docket UM 2001, PGE's Compliance Filing (Mar. 12, 2019).
[2] Docket UM 2001, Order No. 19-074.

This reliance on generic cost assumptions amid rapid changes in technology costs has resulted in systemically high avoided cost prices that guarantee that customers will pay more for Qualifying Facilities (QFs) than they would otherwise pay to receive the same services. This aspect of the current pricing methodology has consistently failed the customer indifference standard.

ii. A QF is paid the total resource cost per MWh multiplied by the MWh of generation the QF delivers to PGE. However, prices are adjusted to move a portion of this total compensation into hours that are more valuable to the system, and away from hours less valuable to the system. Adjustments are also made to reflect the capacity value provided by the QF's resource type.

a. Capacity Value

For both renewable and non-renewable avoided cost pricing, total resource cost is divided into energy and capacity. Energy is a residual value (total resource cost minus capacity). During off-peak hours, pricing reflects energy only.

Capacity value is defined as the cost per MWh of PGE's proxy capacity resource, currently a simple cycle combustion turbine. For renewable pricing, the share of total resource cost assigned to capacity is adjusted to reflect the capacity contribution of a generic Gorge wind resource (the proxy renewable resource). Per the 2016 IRP Update, wind currently receives a 16.73% capacity contribution. The solar capacity contribution was updated to 11.20% in the March 2019 filing. Because of the lower Effective Load Capacity Contribution (ELCC) of a wind resource, capacity is a smaller portion of the total renewable resource cost relative to the capacity portion of the total non-renewable resource cost.

Capacity value is removed from all hours and assigned to on-peak hours only (at a higher price per hour, reflecting the decreased number of hours across which the value is spread). On-peak hours are thus compensated at a higher price than off-peak hours.

Capacity is also adjusted to reflect the type of QF resource being brought to the system. Schedule 201 pricing is currently developed for base load, wind, and solar resources. In all cases, the capacity value corresponding to the proxy resource (wind for renewable; combined cycle thermal for non-renewable) is removed, resulting in an energy-only value. Then capacity value is added back to each of the three pricing options to reflect the value specific to the QF resource type. Solar capacity value has tended to be lower than wind in recent analysis, while base load capacity value is higher than wind. This has the impact of lowering total solar compensation and increasing total base load compensation relative to compensation for a renewable wind facility.

b. Energy Shaping
Renewable resources are modeled to incorporate seasonal variability into the energy pricing. Monthly energy values are shaped via Aurora modeling. Shaping also moves energy value away from off-peak and onto on-peak hours.

Non-renewable pricing reflects the proxy resource of a combined cycle thermal plant. This resource is modeled with variable costs, including fuel. Gas hub pricing varies across each month, introducing seasonality. Because of this, non-renewable energy pricing is not shaped via Aurora modeling.

PGE models its standard (Schedule 201) avoided cost pricing in Excel. The avoided cost workbook incorporates inputs from other Commission-approved models, for instance, resource-specific ELCCs, PGE's cost to integrate wind, and short-term electricity prices. These models are utilized in PGE's IRP process, and approved by the Commission in those processes.

Question #2:

Please explain the process that a QF goes through when requesting an energy sales agreement with a utility. For this process include the following information, and note any differences between applications for standard rates, standard contracts, or non-standard contracts.

a. List any software programs that aid in the application process
b. Provide a complete timeline, with breakdowns for each step of the process
c. Provide a complete list of informational requirements from the QF
d. Provide a list of data/information issues that could impede the contracting process

Response:

a. Software programs include Microsoft Office products (Outlook, Word, and Excel), Google Earth, and Adobe PDF.

Microsoft Office and Adobe programs are used to read, draft, and send documents to applicants seeking Power Purchase Agreements (PPAs). For example, the Initial Information Request (IIR) form is currently an Excel document and PPAs are PDF documents. Sellers will also send PGE Word and PDF documents, such as a lease agreements or FERC 556 forms. Finally, Outlook is used to send and receive PPA documents and correspond with applicants.

Google Earth is utilized to confirm whether the applicant has any projects within 5 miles of their proposed project location, as necessary to ensure compliance with the Commission's site aggregation rules. This is accomplished by using the GPS coordinates provided by the applicant as part of the PPA intake process. For example, if a Seller has two 3 MW PPA requests within 5 miles of each other, both projects would not qualify for standard prices as they would aggregate under the site rules to 6 MW, which exceeds the 3 MW cutoff for solar projects seeking standard prices.

b. PGE manages an electronic mailbox and phone line as the primary point of contact for QF PPA requests, provided below:

E-mail: Qualifying.Facility@pgn.com
Phone number: 503-464-7523
The steps and associated timelines for the contracting process to obtain a PPA are outlined in PGE's currently effective Schedule 201 (for Standard PPAs) and Schedule 202 (for Negotiated PPAs) documents.[3] Those details are also provided below.

The process for both Standard and Negotiated PPAs begins with the Seller requesting to contract their project under PURPA with PGE either via email or phone. Next, PGE sends the Seller the currently effective IIR form, which ensures that the Seller is using the most up-to-date version and submits all required information needed by PGE to understand the Seller's project and PPA request.

For Standard PPAs, PGE will process the IIR form along with the submitted supporting information. If PGE has any questions about the project (such as why the nameplate rating proposed does not match the FERC 556 form, why the Seller's project LLC is not registered with the State of Oregon, or how the Seller determined the project's average and maximum annual output), then PGE will contact the Seller in writing. Once all outstanding questions have been resolved, PGE will issue a Draft PPA. After the Seller approves the Draft PPA, PGE will issue a Final Draft PPA within 15 business days. Finally, after the Seller approves the Final Draft PPA, PGE will provide the Seller with an Executable PPA.

PGE requires up to 15 business days between milestones as PGE's QF team is typically processing multiple PPA requests in various stages of contracting, and often receives multiple PPA requests from the same Developer at the same time. Additionally, the same QF contracting team is also responsible for answering Developer questions, processing requests for ownership changes for executed PPAs, assisting with active QF-related complaint dockets, supporting PURPA policy dockets, tracking and administering executed PPA contractual milestones, providing QF-related data for power cost filings, and other structuring and origination functions.

For Negotiated PPAs, PGE will process the IIR form along with the submitted supporting information and provide the Seller Non-Binding Indicative Prices within 30 business days after the submittal. If PGE has any questions, PGE will contact the Seller in writing, and will provide Non-Binding Indicative Prices once all outstanding questions have been resolved.[4] Afterwards the Seller must notify PGE it is seeking a Draft Negotiated PPA and once that request is made, PGE has 30 days to provide the Seller a Draft Negotiated PPA. After the Draft Negotiated PPA is issued, the Seller must notify PGE if it would like to

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[3] The Schedules and Standard PPAs are available on PGE's website via the following link: https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/install-solar-wind-more/sell-power-to-pge

[4] Non-Binding Indicative prices are non-standard prices calculated based solely on project attributes as provided by the Seller via the IIR form and prior to any PPA negotiations. Furthermore, Non-Binding Indicative prices are calculated based on the currently effective avoided costs, adjusted as allowed per FERC's five factors. Finally, Non-Binding Indicative prices are provided to the Seller in order to help them evaluate if they would like to move forward within a negotiated PPA process.

begin formal PPA negotiations. There is no defined time period for negotiations, although both parties are expected to make good faith efforts to keep the negotiation process moving forward. Finally, after both parties are in full agreement regarding terms and conditions, PGE will issue an Executable PPA within 15 business days.

c. Below is the list of information PGE requires the QF to provide. This list may be updated from time to time if technological, regulatory, or contracting process changes cause PGE to require different information from the Seller.

   i. Seller Information:
      - Seller's name
      - Seller's business structure
      - Seller's state of organization
      - Seller's USPS mailing address
      - List all-natural person or persons or any legal entity or entities who share common ownership with Seller, share common management with Seller, act jointly or in concert with Seller, or exercise influence over policies or action of Seller
      - Map showing all QF sites owned by the Seller within 5 miles of the Facility
      - Facility developer
      - Map showing all QF sites developed or under development by the Facility Developer within 5 miles of the Facility

   ii. Facility Information:
      - Description and number of generators
      - Facility Rating (AC)
      - Facility Rating (DC) [if applicable]
      - Project attributes include information involving the generator(s)
      - Facility is new or existing
         a. If existing: Is the project under contract and until when
      - Description of Facility's metering, communications, and monitoring
      - Staffing plan to achieve COD
      - Description of Facility's station service requirements
      - Demonstrated ability to obtain QF status (FERC 556 Form)
      - Facility one-line diagram

   iii. Facility Location:
      - GPS Coordinates (to 3 decimal places)
      - County
      - State
      - Aerial photo with site boundary
      - Proof of site control

   iv. Project Milestones:
      - Start of Test Energy Deliveries (DD/MM/YYYY)
      - Commercial Operation Date (DD/MM/YYYY)

- End date (DD/MM/YYYY)

v. Project Output:
- Annual Average Output with explanation for the basis of the estimate
- Annual Maximum Output with explanation for the basis of the estimate
- Annual Minimum Output with explanation for the basis of the estimate (if applicable)

vi. Interconnection & Transmission:
- Point of Delivery
- Point of Interconnection description
- Interconnection Queue number
- Interconnection utility
- Transmission Provider(s) [if applicable]
- Transmission Service Request(s) [if applicable]

d. If Seller fails to provide complete and clear information as required by the IIR, PGE contacts the Seller in writing to seek clarification and/or additional information.

Question #3:

Please describe the interconnection process that a QF is currently required to follow. With this description please note any differences between QFs and any other projects requesting interconnection and explain the rationale behind any such differences.

a. List the point of contact in the utility.
b. Provide a timeline that an interconnection request follows. Please include all relevant steps from submission request to actual connection.
c. Provide a complete list of informational requirements from the QF.
d. Provide a list of data/information issues that could impede the interconnection process.
e. Provide a description if and/or how this process interacts with requesting an energy sales agreement.

Response:

a. PGE manages an electronic mailbox and phone line as the primary point of contact for interconnection requests, provided below:

   E-mail: Small.powerproduction@pgn.com
   Phone number: 503-464-8300

b. The timelines and processes that PGE follows for interconnection requests are derived directly from OAR 860-082-0025 as well as OAR 860-082-0045 through OAR 860-082-0060. Please see Attachment A, which provides a detailed timeline and steps for PGE's interconnection requests.

c. The following information is required to consider the interconnection application complete:

- Completed Interconnection Application
    - Interconnection Application can be found on PGE's website at: https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/install-solar-wind-more/sell-power-to-pge
- Application Fee
    - Tier 1: $100
    - Tier 2: $500
    - Tier 3 and 4: $1,000
- Electrical One-Line Diagram
- Site Plan
- Technical Specification Sheets/Brochures for all Lab-Tested System Components i.e. inverters
- Proof of Site Control
- FERC "Notice of Self Certification" for QF (If Applicable)
- Telemetry Design and Protocols (If Applicable - For Projects >3MW)
- Additional Technical Information May be Required to Complete the Studies – (as determined on a case by case basis)

d. The following list contains the most common issues resulting in delays in the interconnection process:

- Application is missing information which results in the application being considered incomplete – the applicant then has 10 business days to provide the missing information;
- Inaccurate or conflicting information in different documents (for example, application and one-line diagram conflict);
- Inaccurate or insufficient location coordinates;
- Applicant need indicate up front if they are a QF or not. Changing designations between a network resource or an energy resource will cause a change in jurisdiction and process.

e. Most QFs execute a PPA before they either begin or complete the interconnection process. This can be problematic because, as a technical matter, the interconnection nameplate rating must be at or above the nameplate capacity of the resource reflect in the PPA in order for the project to deliver its net output to PGE. However, in some circumstances, a QF will learn through the interconnection study process that an interconnection at the nameplate capacity committed to in the PPA will be prohibitively expensive or even impossible to complete. It is for this reason that PGE recommends that QFs complete the feasibility study portion of the interconnection process prior to committing to a project size though the PPA process.

Question #4:

Please provide a list of any utility resources that could help inform QF developers as to locations that would benefit from, or face challenges to development.

Response:

The QF developer community has several ways in which they can obtain information that could aid them in site selection. PGE offers a Pre-Application process as outlined in OAR 860-082-0020 which allows the Applicant to make an informal request and receive certain information regarding the feasibility of interconnecting a small generator facility at a particular point on the public utility's transmission or distribution system prior to submitting a formal application.

Additionally, upon request PGE will provide the following information regarding the interconnection queue:

- Project Queue Number
- County the Project is in
- Application Tier
- Application Status
- AC Nameplate Rating
- Energy Source
- Feeder
- Substation
- Application Complete Date

Also, upon request PGE will provide redacted studies for specific feeders.

Further, if a developer would like to understand the potential interconnection requirements at a given site, they can submit a formal Interconnection Application. During the scoping call for the application, the Applicant is provided their standing in the queue, how many projects are in queue, the aggregate generation on the feeder, the daytime minimum load of the feeder, and the rating of feeder conductors. PGE's engineering team also discusses possible interconnection requirements with the Applicant.

Question #5:

How do utilities treat QFs with storage currently for PURPA purposes?

a. How is the capacity determined for such a project?
b. Would a renewable generator collocated with storage be eligible for renewable avoided cost pricing? Please explain.

Response:

QFs with storage are treated the same as other QFs. Eligibility for a standard PPA is determined based upon the nameplate capacity of the generators (not storage). The type of resource underlying the storage also affects eligibility (solar projects at or under 3 MW and all non-solar projects at or under 10 MW receive standard prices). Furthermore, PGE cannot modify standard prices for eligible projects because standard prices are calculated using a predefined methodology as explained in response to Question #1.

a. Currently, PGE does not assess, on an individualized basis, the capacity of any QF seeking a standard PPA. Standard PPAs incorporate the applicable avoided cost prices as reflected in Schedule 201 and do not allow PGE to calculate the capacity factor of a proposed PPA's underlying project. A QF (including a QF with storage) receives the standard pricing and terms applicable to the underlying generator type. If a QF with storage were able to demonstrate that it will have the same characteristics as a base load generator, PGE would consider offering that QF the standard base load pricing and contract terms. However, PGE has not yet been presented with such a situation.

   For Negotiated PPAs, PGE would negotiate pricing, terms, and conditions that reflect the project's specific characteristics and the value the project provides to PGE. For example, a project with storage is more valuable to PGE if PGE has the ability to control the dispatchability of the storage component in order to ensure capacity and energy are accessible during periods of need.

b. Yes. PGE considers a QF with storage to be the same resource type as the underlying generator (assuming solely project energy is used to supply energy to the storage component). Thus, the generation method and the transfer of RECs are used to determine the applicable avoided cost pricing for Standard PPAs.

<u>Question #6</u>:

When can existing QF projects renew their QF contracts? Can a renewal occur prior to the expiration of the current contract? If so, how long before expiration of the current contract can a QF enter into a new contract?

<u>Response:</u>

Current rules allow existing QF projects to lock in avoided cost prices up to three years before the commencement of energy deliveries. This is true regardless of whether the project is under contract with PGE or another buyer. Although this requirement was recently incorporated into Commission rules, it is not clear that the Commission has ever fully considered the implications.[5] In a declining price environment, utility customers are harmed by QFs locking in pricing as long as 36 months before deliveries, and PGE believes that it is unnecessary to allow existing facilities

[5] *See Petition to Amend OAR 860-029-0040 Related to Small Qualifying Facilities*, Docket No. AR 593, Joint Utilities' Comments at 11-13 (Sept. 5, 2018) (explaining that, in UM 1610, parties questioned whether the three-year timeline applied to existing QFs and that the Commission acknowledged but did not resolve the issue in Order No. 16-174); Order No. 18-422 (Oct. 29, 2018) (adopting Staff's proposed rules and addressing whether the three-year period applies to non-standard contracts but not discussing the Joint Utilities' Comments regarding applicability of the three-year period to existing QFs and not directly addressing or resolving this issue).

so much time, given that they do not face the same permitting, financing and construction timelines as new QFs.

However, given that the existing rules do not allow PGE any flexibility, PGE's business process currently allows for existing QFs to enter into a PURPA PPA up to three years before the start of energy deliveries regardless of whether the project is already under contract at the time of PPA execution.

Question #7:

Please explain transmission requirements for new QFs. Please explain any differences for existing versus new QFs related to transmission requirements.

Response:

There are no differences in transmission requirements for new versus existing QFs. Sellers developing off-system QFs must obtain sufficient long-term firm transmission rights from the Seller's project to a delivery point on PGE's system with sufficient capacity for the output to be received. Long-term firm transmission is necessary because the Seller must be able to reliably deliver the QF's output. Importantly, the avoided cost prices paid to QFs during the deficiency period include a capacity premium, which assumes that they will be able to deliver their output during the hours when they are generating. PGE relies on the QF's output to serve load even during periods of transmission constraints. If QFs do not have secure long-term firm transmission, customers will be paying for capacity that they cannot rely on. Finally, Sellers are kept whole for the transmission costs because PGE's avoided costs include the cost of one leg of long-term firm transmission on BPA's system.

PGE obtains long-term firm point-to-point or network transmission service to deliver both on- and off-system QF output to its load, once the QF has delivered the output to PGE. However, QFs are responsible for any network upgrade or third-party transmission costs imposed by such delivery, if the costs are not accounted for in PGE's avoided cost rates.

Question #8:

How are QF contracts treated in long-term planning processes? Are the assumptions consistent for IRP planning as those used in other internal planning processes? Are existing QF contracts assumed to renew or not renew at the end of a contract? Please explain.

Response:

PGE's 2016 IRP and 2016 IRP Update analysis assumed that 100% of QF contracts executed as of a specified date (January 17, 2018 for the 2016 IRP Update) result in projects that enter PGE's portfolio with the timing and characteristics specified at the time of the contract execution. In other words, PGE has not planned for the energy, capacity, and RPS needs associated with QF resources that have executed contracts with PGE but are not yet online. In supplemental analysis filed as part of the 2016 IRP and in the 2016 IRP Update, PGE also provided sensitivities of its need assessments based on scenarios that included increased and decreased quantities of QF contracts.

PGE's 2019 GRC approved including QF contracts executed through PGE's final November 15 update in each year's NVPC filing. PGE proposed including executed QF contracts in NVPC and using a tracking mechanism to true-up for online dates. Commission Staff proposed a modification to the tracking mechanism, which was agreed to in a stipulation. The treatment of QF contracts in NVPC was approved in Commission Order No. 18-405.

PGE's IRP analysis does not assume that QF contracts are renewed after they expire. PGE takes the same approach for all contracts in the IRP need assessments. The project owners are under no obligation to continue selling their generation to PGE after the expiration of the contract. Recent history has shown that QF owners will enter into agreements with parties other than their local utility if opportunities exist to do so for more beneficial terms. PGE does not presume to know the structure of QF pricing or terms across the region in future years, nor the future opportunities for these projects to enter into non-QF agreements, nor the ability of the projects to operate beyond the term of the executed contract.

Set B

Question #9:

Should the current standard pricing methodology be retained? If not, what should the methodology be? Please describe in detail, and provide examples of where the proposed methodology may currently be in use. If not, in this description include the following:

a. How proposal meets customer indifference standard
b. How proposal meets need for transparency
c. Ability to update avoided costs on a regular basis without the need for an extended regulatory process.

Response:

In brief:

- The current standard avoided cost pricing methodology results in pricing that far exceeds the utilities' true avoided cost.
- PGE believes that avoided cost prices should reflect the market. One way to accomplish this would be to use RFP-based avoided cost pricing, which PGE proposed in UM 2001 and explains in more detail below.
- There may be other approaches to better align avoided cost pricing with market, and PGE looks forward to exploring alternatives in the course of this investigation.

The current standard pricing methodology results in pricing that far exceeds the cost of alternative resources that provide the same value to customers and fails to account for the effects of competition. Therefore, the current methodology should not be retained. First, as mentioned above, one of the key inputs to avoided costs under the current methodology is the overnight cost of capital for a renewable resource, which is taken from the utility's most recent acknowledged IRP. Unfortunately, given the lengthy IRP development and approval process, this input is outdated by the time it is incorporated into avoided cost prices. Specifically, when preparing its IRP, PGE contracts with a third-party consultant who estimates present day overnight capital costs by obtaining data from past projects and forecasts capital cost declines based on past trends. PGE then incorporates this information into its IRP, which undergoes a lengthy review and approval process.

The use of outdated inputs is particularly problematic in the current environment, because the cost of renewable energy projects is decreasing rapidly as technology advances. Technology prices, particularly for wind, solar, batteries, and other evolving technologies, have continued dramatic declines in recent years. These declines have outpaced industry forecasts, such as those used for PGE's IRP. For these reasons, the IRP-based methodology has consistently overestimated the utility's actual avoided cost.

Second, administratively determined avoided costs fail to account for the effects of competition in the market. The Commission requires competitive bidding for major utility resource acquisitions to ensure that utility acquisitions provide the lowest reasonable costs, and the highest benefit-to-cost ratio, that the market can provide. This is the price at which customers are held indifferent to PGE's purchase of QF generation.

For these reasons, PGE recommends that avoided cost pricing should be based on the best available representation of the true costs that customers would experience but for the execution of contracts with QFs. PGE's procurement activities provide the most up-to-date information. Specifically, PGE recommends using the results of its most recent RFP, because PGE is planning to conduct regular RFPs in order to meet Oregon's steeply increasing RPS standards and to provide low cost energy in a cap and trade environment. PGE anticipates a 2-year procurement cadence which may provide regular market-based pricing updates.

Administratively determined cost inputs have consistently overestimated the utility's actual avoided cost. Bidders in RFPs and participants in bilateral negotiations are highly motivated by competitive forces to deliver the lowest cost offer. They work hard to take advantage of every opportunity to reduce costs, including an array of tax benefits.

PGE's recent RFP resulted in a $40.70-levelized price.[6] This price reflects a combination of technologies (wind, solar, and battery) that are more expensive than wind alone but result in a higher capacity contribution (producing a strong benefit-to-cost ratio). The price also reflects risks – which translate into costs – undertaken by the developer, including financial guarantees, securing all relevant land use and environmental permits, and execution of engineering procurement construction (EPC) contracts. Yet QFs – currently offered a $45.19-levelized price[7] – provide fewer services and bear none of these risks, further highlighting the market's ability to undercut generic cost assumptions.

[6] Dec 2020 online date; 2019 dollars.
[7] 15-year levelized price for a 2020 solar project, 2019 dollars.

PGE's proposal for RFP-based prices begins with the $40.70-levelized cost of the RFP resources. Consistent with Commission precedent, PGE proposes to adjust the RFP price for the capacity contribution of each QF resource type, using the Commission-approved capacity values from PGE's 2016 IRP Update. The RFP winning bid has a high capacity value; removing this from the RFP price and adding back the unique capacity value for solar QFs results in an avoided cost price for solar QFs of $36.83,[8] 19% below current pricing.

PGE proposes to use capacity-adjusted RFP-based pricing beginning in the year in which procurement is planned. Given Oregon's steeply increasing RPS standards and possible cap and trade legislation, ongoing procurement is expected in a 2-year cadence.

In the years prior to procurement, PGE's forward market trading curve, inclusive of wheeling, will be utilized as it is today. PGE proposes to use the cost to procure a resource as a price cap during the sufficiency period, thus reflecting the utility's ability to procure when and if market pricing exceeds the cost of procurement.

a. For the reasons explained above, PGE's RFP-based avoided cost proposal is one way to maintain customer indifference. PGE is also considering additional proposals that may leverage similar processes.

b. A market-based avoided cost would meet the need for transparency by: 1) Allowing signatories to a non-disclosure agreement to review the terms of the procurement in detail; and 2) Simplifying the avoided cost model so that it is easier for the Commission and stakeholders to engage with. In the recent RFP, details regarding the winning bid were provided to Staff and many other parties (NIPPC, AWEC, CUB, etc.) pursuant to a modified protective order in the RFP docket, and PGE would similarly provide that information to those same parties in an avoided cost update docket, designated as highly confidential. Accordingly, PGE expects that parties would have adequate access to detailed information regarding PGE's RFP-based avoided cost pricing.

c. Finally, using a price derived from an RFP reduces the need for extended regulatory process to update avoided costs. PGE's proposal will result in a streamlined regulatory process by leveraging the significant oversight already in place to vet and approve the results of a competitive procurement, including engagement of an Independent Evaluator.

Question #10:

Should separate price streams be offered for a nonrenewable and a renewable avoided resource? If yes, please explain why and provide a description of the proposed avoided cost pricing methodology. In this description include the following:

a. How proposal meets customer indifference standard
b. How proposal meets need for transparency

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[8] 15-year levelized price for a 2020 solar project, 2019 dollars.

c. Ability to update avoided costs on a regular basis without the need for an extended regulatory process.

Response:

The current nonrenewable avoided cost methodology is based on a proxy gas plant. It assumes that the proxy plant is the lowest cost resource. The current reality is that utilities are less likely to build gas plants and more likely to procure renewable or carbon-free resources. Given the declining costs of renewable resources and possible carbon cap and trade legislation, it is likely that renewable resource avoided costs are or will be lower than the cost of the proxy gas plant in the future. To maintain customer indifference to QF purchases, the traditional nonrenewable avoided cost cannot be higher than the renewable avoided cost—which is intended to compensate for additional environmental attributes. Therefore, PGE recommends subtracting the value of the environmental attributes from the renewable avoided cost to value the nonrenewable avoided cost in that scenario.

Question #11:

Should documents and models used in the standard pricing and contracting practices be changed to be consistent for all utilities?

a. Should standard PPAs be modified such that the bulk of the document is the same for each utility? Please explain.
b. Should the spreadsheet models used to calculate standard prices be modified so that inputs and outputs are easily found and compared?
c. If standard contracts become homogenized across utilities with less flexibility, how could the OPUC be involved in non-standard contract development and negotiation?

Response:

a. In theory, using common contract forms for all utilities could be helpful to all parties. Also, the utilities have different business practices and proxy resources and need to maintain flexibility to reflect these in their PPAs.

b. PGE believes that its models already are transparent, although PGE understands that the inherent complexities in the current avoided cost methodology pose challenges. The Company would be open to parties' suggestions about how to make them easier to use.

c. Based on PGE's experience, QFs will always prefer the standard contract approach to negotiating (hence developers will space projects to comply with the site aggregation rules)—regardless of whether standard contracts are homogenized. That said, PGE supports QFs' ability to access a Commission dispute resolution process if there is an issue in negotiations.

Question #12:

Please provide any ideas related to generally improving the efficiency of the regulatory process associated with updating avoided cost prices

Response:

See response to Question #9.

Question #13:

Please explain an optimal process for a QF requesting an energy sales agreement with a utility. For this process please note any differences between applications for standard rates, standard contracts, or non-standard contracts.

Response:

Once a QF PPA is executed, PGE incorporates the project's output into our long-term resource planning process. Therefore, PGE is seeking a higher level of certainty than it receives today that the contracted-for project will materialize on schedule and fulfill its output specifications as stated within the executed PPA. Unfortunately, the bulk of the PPA requests received by PGE for both standard and non-standard contracts lack adequate prior due diligence. Project locations are selected without factoring in deliverability constraints or interconnection costs, PPA milestones are provided without any permitting or construction timeline considerations, and project attributes are provided without selection of generation equipment.

For both Standard and non-Standard PPAs, the optimal process would ensure that sufficient development activities have occurred whereby the Seller is able to provide concrete project information and future milestone dates during the PPA intake process. This is mutually beneficial as PGE can fully understand the project proposal and the Seller's executed PPA is more likely to achieve commercial operation. PGE believes that if projects were more fully developed at the time of initial contact, the PPA application and negotiation process would likely be able to proceed more quickly.

Question #14:

Please describe an optimal interconnection process for a QF requesting interconnection.

Response:

PGE's optimal interconnection process would follow the existing interconnection rules in OAR 860-082 and would look as follows:

First, PGE would receive a complete application along with the application fee. Included with the application would be the supporting documentation such as electrical one-line diagram, site plan, specification sheets, proof of site control, telemetry design and FERC notice of self-certification.

The information in the supporting documentation would accurately reflect the information contained within the interconnection application.

Additionally, the applicant would indicate upfront if they are a QF or not. Knowing if the project will be a network resource or an energy resource early in the interconnection process ensures the projects are studied under the correct jurisdiction and accurately reflect the requirements to interconnect.

Within 10 business days PGE would review and notify the developer that their application was considered complete. A scoping call would be scheduled within 10 business days of notifying the developer the application was complete. The scoping call would identify all the interconnection requirements.

Following completion of the scoping call, PGE would issue a Feasibility Study Agreement within 5 business days. The Applicant would return the Feasibility Study Agreement and study deposit within 15 business days. Upon receipt of the Feasibility Study Agreement PGE would begin its review. Within 60 business days, PGE would complete the Feasibility Study and provide the results to the Applicant. At the conclusion of the study PGE would host a call to review the study results. Finally, PGE would invoice the Applicant for the actual costs to conduct the study.

The same process would occur for both the System Impact Study and the Facility Study.

At the conclusion of the Facility Study, PGE would provide the Applicant within 5 business days the Interconnection Agreement which contains both the interconnection requirements as well as the estimated time and costs to complete the work. The Applicant would return the Interconnection Agreement along with the $10,000 deposit promptly.

PGE would then start the engineering work associated with the interconnection requirements. As soon as the engineering is complete, materials would be ordered. Once all the materials have arrived, the PGE work would be scheduled. As PGE is completing the interconnection requirements, the Applicant would also be constructing their facilities. Ideally both PGE and the Applicant would complete construction at the same time. While both parties are constructing it would be good to have bi-weekly meetings to understand each other's progress.

When construction is complete the facility would be commissioned and authorization to operate the facility would be given.

Finally, a final invoice would be provided to the Applicant for the work completed on PGE's system.

<u>Question #15</u>:

How should storage be treated under PURPA implementation? Please discuss treatment for stand-alone storage, storage collocated with non-renewable generation, and storage collocated with renewable generation. Provide the applicable avoided cost pricing approaches for the listed possibilities.

Response:

PGE is just beginning to consider how the complexities associated with storage may impact the value of QF projects and does not have a proposal for avoided cost pricing of storage projects at this time.

PURPA policies regarding storage projects should evaluate the benefits of pairing storage with renewable generation and the value provided to PGE's customers. Those policies should at minimum consider the following:

- The source of the charging energy
- Charging control and limitations
- Changes to the generation profile of a paired facility
- Changes in storage use and performance over time (e.g. shifting to meet peak load next year is not the same as shifting to meet it 5 years from now)
- Degradation of storage technology and impacts to storage capacity
- Line losses and round-trip efficiency
- Capabilities for other services

Question #16:

How should existing projects be treated under PURPA implementation? Please address the following, in addition to any other relevant topics.

a. Renewals
b. Pricing (including capacity treatment)

Response:

See generally, PGE's response to question #6.

a. PGE would be open to entering standard or non-standard contracts with existing projects up to12 months prior to expiration of the QF's existing PPA.

   Existing project owners claim they need to lock in avoided cost prices well ahead of the future PPA start date in order to finance project maintenance activities. Given that existing projects are already generating revenue from their existing PPA, Sellers should already be routinely conducting capital and operating activities for their facilities in order to maintain project reliability.

b. PGE recommends that existing QFs should receive the same pricing and capacity treatment as new QFs. So long as QFs are free to sell their output to another utility at the conclusion of their PPA term, PGE cannot rely upon them to provide capacity after the expiration of the existing PPA.

Question #17:

Should the existing dispute resolution process be continued? If not, how should it be changed?

Response:

In PGE's experience, neither the existing dispute resolution process for negotiated agreements (OAR 860-029-0100) nor the process for standard agreements (per the stipulation adopted in Order No. 15-130) is used. The current standard-contract process (based on the telecommunications arbitration provisions in OAR 860-016-0030) is not adaptable for standard contract disputes. The current negotiated-contract process contains unworkable timelines (e.g., requirement to provide detailed response to a complaint and accompanying testimony in 10 calendar days). PGE believes that the Commission should adopt revised dispute resolution processes that are accessible, efficient, and adapted to the types of disputes that arise.

PGE has encountered three primary types of PURPA disputes:

1. Disputes regarding eligibility for a particular type of contract, pricing, etc.
2. Disputes regarding timing of a LEO and entitlement to specific pricing.
3. Disputes regarding interpretation of an existing contract term.

Therefore, PGE proposes the following dispute resolution framework for both standard and negotiated PPAs:

- Both QFs and utilities have the ability to access mandatory but non-binding ALJ mediation or other informal dispute resolution before a complaint is filed.

- Both QFs and utilities may use the regular complaint process under ORS 756.500 to resolve disputes if the informal dispute resolution process is unsuccessful in resolving the dispute.

- Both QFs and utilities may ask the Commission to resolve policy issues. This process could be similar to a request for declaratory ruling (which the Commission has found to be available only when requesting interpretation of rules or statutes and which is binding only on the petitioner[9]), could occur through the regular complaint process, or could utilize a separate mechanism. Once such a case is initiated, interested parties should be permitted to intervene. A process like this is necessary because important policy questions arise regularly that parties did not foresee or expect in the latest policy docket—particularly as technology and the renewable industry advance and evolve rapidly. When a dispute between two parties raises such an issue, the parties need to be able to obtain Commission guidance and other interested and potentially affected parties need to be able to participate.

[9] *See* , e.g., Docket No. UM 1931, Order No. 18-174 at 12 (Mar 23, 2018) (stating application of a declaratory ruling "must be limited to a rule or statute"); Docket No. DR 52, Order No. 18-160 at 1 and App'x A at 5-6 (May 10, 2018) (adopting Staff recommendation and declining to consider petition for declaratory ruling that did not identify a rule or statute in question and raised issues that would affect parties other than the petitioner); Docket No. UM 1805, ALJ Ruling (Jan. 19, 2017) (rejecting declaratory ruling procedure as violation of statute); Docket No. DR 51, Order No. 16-378 (Oct. 12, 2016) (treating petition for declaratory ruling as complaint).

Question #18:

Please share your recommendations to reduce the volume of litigation regarding complaints.

Response:

Institute an effective informal dispute resolution process and require that it be used prior to filing a formal complaint. Provide clear guidance in the policy docket. Continuously evaluate PURPA policies to ensure they remain up-to-date and to timely respond to policy changes (e.g., cap and trade) to ensure customer indifference is maintained. Answer questions and resolve disputes that arise promptly and comprehensively so that all parties benefit from Commission guidance on common issues.

Question #19:

What existing resources (educational, etc.) do you know of that could benefit the Commission and other stakeholders during or prior to the investigation?

Response:

PGE recommends the following resources:

- Stakeholder comments filed in FERC Docket No. AD16-16 for Implementation Issues Under PURPA.[10]
- "Aligning PURPA with the Modern Energy Landscape" Whitepaper published in October 2018 by the National Association of Regulatory Utility Commissioners (NARUC).[11]

Question #20:

What is the best process for the Commission to educate, inform and engage itself and its stakeholders around the questions related to PURPA implementation?

Response:

PGE supports Staff's direction as described in these stakeholder questions – the Commission should divide and investigate PURPA implementation issues in phases. This will encourage a more streamlined resolution for some issues and reserves the opportunity for a robust investigation into complex issues. Regular schedules for stakeholder comments and workshops discussion will ensure the investigation process is not impeded. PGE also recommends that the Commission and Staff establish clear schedules for its investigation process well in advance so that parties can plan to participate.

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[10] *See* PGE's comments: (https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14754982)
[11] *See* NARUC whitepaper: (https://pubs.naruc.org/pub.cfm?id=E265148B-C5CF-206F-514B-1575A998A847)

As part of the investigative process, PGE recommends that the Commission conduct a survey of PURPA implementation approaches in other states—particularly those that have similarly experienced significant amounts of QF contract requests.

<u>Question #21</u>:

Given recent utility practice of acquiring resources on an economic basis, outside of need, should the Commission change the current practice of using IRP resource acquisition to define resource sufficiency/deficiency (thereby defining payments for capacity)?

a. If yes, how should the Commission determine eligibility and pricing for capacity payments?

<u>Response:</u>

Under PGE's RFP-based pricing concept, PGE proposes to maintain the current concept for determining sufficiency/deficiency, as explained above in response to Question #9. To the extent that PGE may consider different approaches to the avoided cost pricing methodology, this response may change.

<u>Question #22</u>:

When in the process of contracting should a legally enforceable obligation (LEO) be obtained?

<u>Response:</u>

Under the Commission's current PURPA implementation policies the LEO has become a free option for developers, in that developers are able to establish a LEO early in the contracting process to lock in the most advantageous avoided cost pricing, without any real penalty for failing to follow through and develop the project. As a result, PGE is unable to adequately plan for QF resources coming online. Given the current scope of QF activity on PGE's system, this results in uncertainty at a level of hundreds of MW of generating capacity. For these reasons, PGE believes that the LEO should occur later in the contracting process. This concept of delaying the LEO until the QF establishes "viability" has been implemented in other states (e.g., Texas, New Mexico), and it has been validated by appellate courts. PGE understands concerns regarding QF financing, but PGE believes the Commission should look to balance the utility and QF interests and implement a LEO policy that allows the LEO to be established at a time in the process where the QF has an obligation to actually follow through in development so that PGE can better plan for these resources.

<u>Question #23</u>:

Currently, a QF can have a LEO or executed contract, fail to achieve commercial operation, and as a practical matter not be required to pay a penalty to the utility because the utility's costs to replace the QF's power do not exceed the costs the utility would have incurred under the contract. Would imposing a different type of penalty for non-performance once a LEO is obtained or a contract executed be appropriate? Please explain.

Response:

PGE views the Standard contract as a 'free option'. Sellers need complete very little to no prior due diligence before submitting a PPA request. As previously shared, project locations are selected without factoring in deliverability constraints or interconnection costs, PPA milestones are provided without any permitting or construction timeline considerations, and project attributes are provided without selection of generation equipment. Furthermore, individual developers will submit multiple concurrent PPA requests, each under a newly created LLC, only some of which ever reach fruition.

PGE recommends adding Performance Assurance criteria to help mitigate the 'free option'. PGE proposes Sellers pay Performance in the form of Cash or Letter of Credit as a condition of PPA execution, calculated based on the project's nameplate rating (in kW). If the PPA fails to achieve commercial operation and is terminated by the Buyer or if it is terminated by the Seller prior to commercial operation, Seller forfeits the Performance Assurance and the funds are provided to customers.

This would encourage developers to execute PPAs for projects that have a high likelihood of reaching commercial operation. Additionally, this would discourage the submission of multiple PPA requests without sufficient development due diligence.

Question #24:

What is required for a QF project to receive financing?

Response:

PGE understands that an executed PPA that provides for up to 15 years of fixed prices is sufficient for a QF project to secure financing, as demonstrated by the numerous PPAs signed in Oregon. And it is entirely possible that less than 15 years of fixed prices would be adequate.

Question #25:

Assuming a two-phase process, what issues do you believe could be fast-tracked within Phase 1?

Response:

Phase 1 should address the following issues:

- Avoided cost pricing methodology
- Existing QF contract renewals
- LEO Criteria and Performance Assurance

<u>Question #26</u>:

Assuming a two-phase process, what issues do you believe need additional time for analysis? (i.e. should be addressed in Phase 2)

<u>Response:</u>

Phase 2 should address the following issues:

- Interconnection requirements
- Standard Contract Cap
- Treatment of Storage
- Standard Contract among utilities

<u>Question #27</u>:

Please share one to two specific suggestions you would make to change how the cost of network upgrades are assigned and socialized? Describe why your suggestion is reasonable in terms of how the cost would be allocated?

<u>Response:</u>

PGE believes that the Commission's current policies requiring QFs to bear the costs of upgrades caused by their projects are legally correct and must be maintained. In Order No. 10-132, the Commission appropriately recognized the distinction between the FERC and state interconnection principles regarding allocation of network upgrade costs. The Commission found that the principles that might support passing these costs on to utility customers are not consistent with PURPA's avoided cost rate limitation, which mandates that utility customers be held indifferent to the purchase of QF power. This continues to be true today, and PGE encourages the Commission to confirm that the treatment of network upgrade costs under PURPA is distinguishable from non-PURPA interconnections – at least outside of situations where the QF can demonstrate system benefits, in which case some socialization may be appropriate. However, socializing these costs should not be the norm, and QFs should continue to have to pay the costs for network upgrades—and other transmission-related costs—driven by their interconnection.

<u>Question #28</u>:

Please provide any additional comments or concerns that you would like to see addressed in this investigation.

<u>Response:</u>

- Improving scheduling and forecasting requirements for QFs (increasingly important as the amount of QF output delivering increases, and as PGE is an EIM participant and must adhere to CAISO's requirements.

- Integration charges for all variable resources (currently only applies to wind).
- 5-mile rule should be strengthened.
- Improve or replace the mechanical availability guarantee (MAG), which is difficult to enforce. Consider minimum delivery requirements for all QFs.
- Strengthen credit support requirements (current Commission policy allowing QFs to offer step-in rights or senior lien as credit support in the standard PPA is not commercially reasonable and does not provide meaningful value to the utility in the event of default).
- Determine what prices should apply to QFs that are not wind or solar but do not have a capacity contribution comparable to base load.
- Requiring any increase in nameplate capacity of a QF with an executed PPA to be compensated at then-current avoided cost prices.

Conclusion

PGE appreciates the opportunity to provide information for developing scoping of the investigation and looks forward to further discussion at the upcoming workshop. Should you have any questions regarding these comments, please contact Colin Wright at (503) 464-8011.

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

Respectfully submitted,

PORTLAND GENERAL ELECTRIC COMPANY

Karla Wenzel
Manager, Pricing and Tariffs
121 SW Salmon Street, 1WTC0306
Portland, OR 97204

Attachment A

Timeline and Steps for PGE’s Interconnection Process

Tier 1
Inverter Based System 25 kW or Less

Application Received

From receipt of application PGE must give notification to Applicant with **10 business days** of whether application is complete.

If the application is incomplete, PGE must provide a list of information needed to complete the application.

Applicant must provide the listed information with **10 business days** of receipt of the list or the application is deemed withdrawn.

Engineering Review

PGE analyzes interconnection request within 30 business days based on criteria listed in OAR 860-082-0045 and good utility practice.

If a small generator facility is not approved under the Tier 1 interconnection review procedure, Applicant may submit a new application under the Tier 2, Tier 3, or Tier 4 review procedures.

At the Applicants request, PGE to provide a written explanation of the reasons for denial within **5 business days** of receipt of the request.

Interconnection Agreement

PGE to deliver an executable Interconnection Agreement to the Applicant within **5 business day**s after approval of an interconnection application.

Applicant must execute the Interconnection Agreement within **15 business days** of receipt or their application is deemed withdrawn.

Commissioning

Applicant to provide PGE written notice at least **20 business days** before the planned commissioning for the small generator facility.

The public utility has the option of conducting a witness test at a mutually agreeable time within **10 business days** of the scheduled commissioning.

The public utility must provide written notice to the applicant indicating whether the public utility plans to conduct a witness test or will waive the witness test.

If the public utility notifies the applicant that it plans to conduct a witness test, but fails to conduct the witness test within **10 business days** of the scheduled commissioning date or within a time otherwise agreed upon by the applicant and the public utility, then the witness test is deemed waived.

If the witness test is conducted and is not acceptable to the public utility, then the public utility must provide written notice to the applicant describing the deficiencies within five business days of conducting the witness test.

The public utility must give the applicant **20 business days** from the date of the applicant's receipt of the notice to resolve the deficiencies.

If the applicant fails to resolve the deficiencies to the reasonable satisfaction of the public utility within **20 business days**, then the application is deemed withdrawn.

Tier 2
Lab Tested Equipment or Field Tested Equipment 2 MW or Less

<u>Application Received</u>

From receipt of application PGE must give notification to Applicant with **10 business days** of whether application is complete.

If the application is incomplete, PGE must provide a list of information needed to complete the application.

Applicant must provide the listed information with **10 business days** of receipt of the list or the application is deemed withdrawn.

<u>Scoping Meeting</u>

PGE to schedule the scoping meeting within **10 business days** of notifying the Applicant the application is complete.

Within **20 business days** after a public utility notifies an applicant that its application is complete or a scoping meeting is held, whichever is later, the public utility must:

> Evaluate the application using the Tier 2 approval criteria; Review any independent analysis of the proposed interconnection provided by the applicant that was performed using the Tier 2 approval criteria; and
>
> Provide written notice to the applicant stating whether the public utility approved the application. If applicable, the public utility must include a comparison of its evaluation to the applicant's independent analysis.

<u>Engineering Review</u>

PGE analyzes interconnection request within 30 business days based on criteria listed in OAR 860-082-0050 and good utility practice.

If a small generator facility is not approved under the Tier 2 interconnection review procedure, Applicant may submit a new application under the Tier 3, or Tier 4 review procedures.

At the Applicants request, PGE to provide a written explanation of the reasons for denial within **5 business days** of receipt of the request.

When a higher queued interconnection request withdraws from the queue, PGE reserves the right to restudy a project(s) as the interconnection requirements may have changed.

<u>Interconnection Agreement</u>

PGE to deliver an executable Interconnection Agreement to the Applicant within **5 business day**s after approval of an interconnection application.

Applicant must execute the Interconnection Agreement within **15 business days** of receipt or their application is deemed withdrawn.

<u>Commissioning</u>

Applicant to provide PGE written notice at least **20 business days** before the planned commissioning for the small generator facility.

The public utility has the option of conducting a witness test at a mutually agreeable time within **10 business days** of the scheduled commissioning.

The public utility must provide written notice to the applicant indicating whether the public utility plans to conduct a witness test or will waive the witness test.

If the public utility notifies the applicant that it plans to conduct a witness test, but fails to conduct the witness test within **10 business days** of the scheduled commissioning date or within a time otherwise agreed upon by the applicant and the public utility, then the witness test is deemed waived.

If the witness test is conducted and is not acceptable to the public utility, then the public utility must provide written notice to the applicant describing the deficiencies within five business days of conducting the witness test.

The public utility must give the applicant **20 business days** from the date of the applicant's receipt of the notice to resolve the deficiencies.

If the applicant fails to resolve the deficiencies to the reasonable satisfaction of the public utility within **20 business days**, then the application is deemed withdrawn.

Tier 3
10 MW or Less and will not export beyond the point of interconnection

Application Received

From receipt of application PGE must give notification to Applicant with **10 business days** of whether application is complete.

If the application is incomplete, PGE must provide a list of information needed to complete the application.

Applicant must provide the listed information with **10 business days** of receipt of the list or the application is deemed withdrawn.

Scoping Meeting

PGE to schedule the scoping meeting within **10 business days** of notifying the Applicant the application is complete.

Within **20 business days** after a public utility notifies an applicant that its application is complete or a scoping meeting is held, whichever is later, the public utility must:

> Evaluate the application using the Tier 3 approval criteria; Review any independent analysis of the proposed interconnection provided by the applicant that was performed using the Tier 3 approval criteria; and
>
> Provide written notice to the applicant stating whether the public utility approved the application. If applicable, the public utility must include a comparison of its evaluation to the applicant's independent analysis.

Engineering Review

PGE analyzes interconnection request within **60 business days** based on criteria listed in OAR 860-082-0055 and good utility practice.

If a small generator facility is not approved under the Tier 3 interconnection review procedure, Applicant may submit a new application under the Tier 4 review procedures.

At the Applicants request, PGE to provide a written explanation of the reasons for denial within **5 business days** of receipt of the request.

When a higher queued interconnection request withdraws from the queue, PGE reserves the right to restudy a project(s) as the interconnection requirements may have changed.

Interconnection Agreement

PGE to deliver an executable Interconnection Agreement to the Applicant within **5 business day**s after approval of an interconnection application.

Applicant must execute the Interconnection Agreement within **15 business days** of receipt or their application is deemed withdrawn.

Commissioning

Applicant to provide PGE written notice at least **20 business days** before the planned commissioning for the small generator facility.

The public utility has the option of conducting a witness test at a mutually agreeable time within **10 business days** of the scheduled commissioning.

The public utility must provide written notice to the applicant indicating whether the public utility plans to conduct a witness test or will waive the witness test.

If the public utility notifies the applicant that it plans to conduct a witness test, but fails to conduct the witness test within **10 business days** of the scheduled commissioning date or within a time otherwise agreed upon by the applicant and the public utility, then the witness test is deemed waived.

If the witness test is conducted and is not acceptable to the public utility, then the public utility must provide written notice to the applicant describing the deficiencies within five business days of conducting the witness test.

The public utility must give the applicant **20 business days** from the date of the applicant's receipt of the notice to resolve the deficiencies.

If the applicant fails to resolve the deficiencies to the reasonable satisfaction of the public utility within **20 business days**, then the application is deemed withdrawn.

Tier 4
10 MW or Less

Application Received

From receipt of application PGE must give notification to Applicant with **10 business days** of whether application is complete.

If the application is incomplete, PGE must provide a list of information needed to complete the application.

Applicant must provide the listed information with **10 business days** of receipt of the list or the application is deemed withdrawn.

Scoping Meeting

PGE to schedule the scoping meeting within **10 business days** of notifying the Applicant the application is complete.

PGE to give notice of approval of application to Applicant within 15 business days of the scoping meeting studies are necessary, no system upgrades or facility modifications are required, and no safety or reliability issues.

Feasibility Study

PGE provides the Feasibility Study Agreement to Applicant within **5 business days** of the scoping meeting.

Applicant must execute the Feasibility Study Agreement within **15 business days** or their application is deemed withdrawn.

PGE to provide study results to Applicant within **5 business days** of study completion.

PGE completes feasibility study within **60 business days** of executed Feasibility Study Agreement. The same timeline applies to the system impact study and facilities study.

System Impact Study

PGE provides the System Impact Study Agreement to Applicant within **5 business days** of completing the feasibility study or following the scoping meeting date, if no feasibility study is required or need for feasibility study is waived.

Applicant must execute the System Impact Study Agreement within **15 business days** or their application is deemed withdrawn.

PGE to provide study results to Applicant within **5 business days** of study completion.

PGE completes system impact study within **60 business days** of executed System Impact Study Agreement.

PGE to give notice of approval of application to the Applicant within 15 business days of completion of the system impact study, if all criteria are met and no interconnection facilities or system upgrades are required.

Facilities Study

PGE provides the Facilities Study Agreement to Applicant within **5 business days** of completing the system impact study or following the scoping meeting date, if no feasibility study or system impact study is required.

Applicant must execute the Facilities Study Agreement within **15 business days** or their application is deemed withdrawn.

PGE to provide study results to Applicant within **5 business days** of study completion.

PGE completes facilities study within **60 business days** of executed Facilities Study Agreement.

PGE to give notice of approval of application to the Applicant within 15 business days after the Applicant agrees to pay for interconnection facilities and system upgrades identified in the facilities study.

Interconnection Agreement

PGE to deliver an executable Interconnection Agreement to the Applicant within **5 business day**s after approval of an interconnection application.

Applicant must execute the Interconnection Agreement within **15 business days** of receipt or their application is deemed withdrawn.

Commissioning

Applicant to provide PGE written notice at least **20 business days** before the planned commissioning for the small generator facility.

The public utility has the option of conducting a witness test at a mutually agreeable time within **10 business days** of the scheduled commissioning.

The public utility must provide written notice to the applicant indicating whether the public utility plans to conduct a witness test or will waive the witness test.

If the public utility notifies the applicant that it plans to conduct a witness test, but fails to conduct the witness test within **10 business days** of the scheduled commissioning date or within a time otherwise agreed upon by the applicant and the public utility, then the witness test is deemed waived.

If the witness test is conducted and is not acceptable to the public utility, then the public utility must provide written notice to the applicant describing the deficiencies within five business days of conducting the witness test.

The public utility must give the applicant **20 business days** from the date of the applicant's receipt of the notice to resolve the deficiencies.

If the applicant fails to resolve the deficiencies to the reasonable satisfaction of the public utility within **20 business days**, then the application is deemed withdrawn.