BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1934

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2018 Request for Proposals for Renewable Resources.	)))))))	NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION COMMENTS

I. INTRODUCTION

Northwest and Intermountain Power Producers Coalition ("NIPPC") provides these Comments to the Oregon Public Utility Commission (the "Commission") regarding Portland General Electric Company's ("PGE's") 2018 Request for Proposal ("RFP"). NIPPC urges the Commission to make significant changes in the RFP to provide an opportunity for nonutility-owned generation to compete against PGE's Benchmark Resource and other utility-owned options.

NIPPC notes that it reached out to PGE well before it filed its 2018 RFP to request that PGE work with NIPPC to design an RFP that would limit litigation over disputed RFP terms and conditions. PGE refused to do so, and did not adopt many of the recommendations that NIPPC made regarding PGE's 2016 RFP. NIPPC is disappointed that it has to file voluminous comments regarding a contested RFP, instead of lining up in support of PGE's efforts to meet its renewable resource needs.

NIPPC's comments have two primary themes. First, the Commission should remove provisions that bias the RFP in favor of PGE's Benchmark Resource or other ownership options. Second, the Commission should remove provisions that reduce the number of qualified bidders. There are least cost and least risk resource options that will not be able compete, or even participate, under PGE's RFP as proposed. These limitations could result in PGE's higher cost and riskier Benchmark Resource winning the RFP essentially by default.

II. COMMENTS

A. Transmission Is the Most Important Aspect of this RFP, and Bidders Should be Allowed to Utilize the Transmission Assets that PGE's Ratepayers Have Paid for and Should Be Able to Offer Creative Transmission Solutions

NIPPC raises two basic issues regarding PGE's transmission requirements. First, PGE has excess transmission rights on BPA's system that it intends to use for its Benchmark Resource, but will not allow other bidders the ability to use these rights. If PGE is truly ownership agnostic, then it should use its transmission rights to purchase the least cost and least risk power regardless of ownership. Second, PGE has imposed a requirement that only the most expensive transmission service available be used in the RFP (which happens to be the same type of transmission that PGE has rights to and plans to use for its Benchmark Resource). Bidders should be encouraged to submit bids using any combination of firm, conditional firm and short-term firm, if that results in more advantageous resource options for ratepayers.

Section 6.1.6 of PGE's draft RFP provides that "PGE will not entertain Bids that propose assignment of PGE's transmission rights to deliver to an acceptable delivery point."[1] Why not? Section 6.1.6 also requires bidders to acquire "long-term firm transmission service to deliver to an acceptable delivery point." From a public policy

---

1 Section 4.3 makes clear that for off-system resources, the only acceptable delivery point is BPAT.PGE meaning that the remote renewable resources that PGE is seeking must deliver through BPA. This means that PGE's RFP requires bidders to deliver via Bonneville Power Administration's ("BPA's") transmission system.

perspective and given BPA's difficulties in processing all transmission requests, these requirements are a disaster because they are biased in favor PGE's Benchmark Resource, prevent lower cost and creative transmission arrangements, and would ultimately require unnecessary over-construction of the transmission grid to achieve a "competitive" wholesale market for generation. NIPPC urges the Commission to carefully consider why these requirements are in the RFP and whether keeping them benefits PGE's ratepayers.

The Commission should carefully scrutinize PGE's transmission requirements, because transmission availability will significantly influence the overall success of bids. The RFP requires bidders to compete for limited BPA long term-firm point to point service—the most expensive type of transmission— which artificially limits the number of bids able to enter the competition and results in unnecessary costs to PGE's ratepayers and the region. For example, if the RFP were for only 150 MW, in order for there to be ten eligible bidders there would need to be 1,500 MW of unutilized transmission capacity able to reach PGE's system (150 MW for each bid). It is unlikely that the region—including PGE's ratepayers—could afford to build and maintain a transmission system with this level of costly and unneeded surplus transmission capacity. In the end only 150 MW of actual transmission would ultimately be needed and not 1,500 MW. Furthermore, when Boardman transmission is freed-up in 2020 when Boardman is retired, no additional transmission will be needed at all.

PGE has most likely included these transmission requirements for the primary purpose of limiting the number of eligible bids. PGE already controls enough surplus transmission capacity to ensure that its Benchmark Resource can reach its load; and PGE likely recognizes that competing projects will have difficulty arranging similar transmission rights within the required timeframe. Would PGE include this requirement if it would make the Benchmark Resource ineligible or if the Benchmark Resource did not already meet this requirement?

In fact, not only does PGE have sufficient transmission capacity for its Benchmark Resource, but PGE has additional transmission rights and will soon have another 500 MW of surplus transmission that should be made available to the successful bidder. All of PGE's transmission holdings were bought and paid for by its ratepayers; PGE should use those rights to benefit its ratepayers rather than its shareholders. Any transmission reservations currently held, in queue or optioned by PGE on the BPA transmission system that are above PGE's legitimate existing and forecasted transmission needs—including transmission that would be made available to PGE's Benchmark Resource—should be assumed to be available to the resource selected in this RFP, regardless of ownership of those resources. PGE is using its surplus transmission rights to limit competition by refusing to allow bidders to utilize PGE's existing surplus transmission rights for resources that will serve PGE's ratepayers for the next 20 years.

PGE's requirement to provide long-term firm transmission is also overly restrictive and imposes unnecessary costs that are ultimately paid by PGE's ratepayers. Section 6.1.6 also requires bidders to acquire "long-term firm transmission service to deliver to an acceptable delivery point." If this RFP were for a capacity resource needed to ensure that PGE could serve its peak load reliably, then firm transmission service would be appropriate. But this RFP is for renewable energy resources needed to satisfy PGE's Renewable Portfolio Standard ("RPS") requirement for renewable energy. PGE is unlikely to rely on these resources to meet its peak load; therefore, firm point-to-point transmission service associated with these resources is unreasonably inefficient and unreasonably costly to PGE's ratepayers. Bidders should be allowed to combine long-term firm with other transmission products, like conditional-firm and hourly-firm market sales when forming their bids. This is especially true for Independent Power Producer ("IPP") bids that absorb the risk from any potential curtailments.

Finally, PGE should assume that any renewable resource acquired through this RFP, regardless of ownership, will be integrated into PGE's Balancing Area Authority ("BAA") to the largest extent possible. PGE should do this by removing the requirement that power purchase agreement ("PPA") bidders embed the costs of 20 years of BPA balancing service in their bids. To the extent renewable resource bids cannot be integrated into PGE's BAA immediately, (e.g., the communication and telemetry does not enable the resource to be immediately pseudo-tied and dynamically scheduled) PGE's evaluation should recognize the unnecessary costs to PGE ratepayers of the requirement to include the cost of resource balancing (optional ancillary services) into such bids. PGE's decision to purchase balancing services from BPA through PPA bidders acting as middlemen is not appropriate and will lead to higher costs and add long-term risks for PGE ratepayers.

1. PGE's Transmission Rights Belong to PGE's Ratepayers

Despite any claims to the contrary, PGE does have surplus transmission. According to reservations publicly available via OASIS, PGE currently appears to have more long term firm, point to point transmission service reservations on BPA's system than PGE needs.[2] PGE also has shorter-term positions, which are more difficult to track in OASIS, but it is important to understand that *any* short-term positions supplement their transmission availability over and above their long-term firm needs.[3] More importantly, however, when PGE's Boardman facility closes in 2020, PGE will have an additional 500 MW of surplus transmission rights that it could redirect to new resources.

PGE ratepayers will be better off if PGE's surplus transmission rights are made available to bidders that can demonstrate the Boardman transmission can be redirected to their proposed project on a firm basis. Going back to PGE's 2009 IRP, PGE has had excess BPA transmission from Port Westward to Trojan, but has consistently resisted letting bidders utilize this transmission.[4] The availability of PGE's transmission is even more critical to developers now that PGE has determined new resources interconnected to the PacifiCorp West transmission system are ineligible to bid into the RFP.[5] PGE's insistence that bidders go and find their own firm transmission is unfair and an inefficient use of its ratepayer-funded resources. PGE's Boardman transmission rights are particularly fungible, and PGE can redirect to almost anywhere in the region under BPA's rules. For bidders that are able to repurpose the Boardman surpluses, PGE could simply add appropriate transmission costs during bid evaluation.

---

[2] PGE has nearly 4,400 MW of long-term firm point to point transmission service reserved at BPAT with rollover rights whereas its total network resource portfolio is only 3,326 MW. PGE's 2016 peak load (on August 18, 2016) was only 3,726 MW.

[3] PGE has deferred transmission rights available on BPA's system, as well as what are effectively options, or future rights that it acquired pursuant to BPA's first network open access settlement agreement.

[4] <u>Re PGE Net Variable Power Costs (NVPC) and Annual Power Cost Update (APCU)</u>, Docket No. UE 286, ICNU Testimony (May 27, 2014).

[5] NIPPC disagrees with PGE about the availability of the PACW.PGE POD, but is not challenging that issue in this RFP.

The Commission should take measures to ensure that PGE's portfolio of transmission positions is used for the benefit of PGE's ratepayers to access the least cost and risk resources available. The Commission has previously threatened PGE with a prudency disallowance if it refused to make its assets available to third party bidders.[6] Accordingly, the Commission should recognize that PGE will have *at least* 500 MW of firm transmission rights beyond those needed by PGE ratepayers when Boardman retires in 2020. Given these surpluses, the Commission should direct PGE to revise its RFP to make its surplus transmission available to support any project bid that is able to use it.

2. Requiring Long-Term Firm Transmission Over BPA's Transmission System Unnecessarily Limits the Pool of Potential RFP Candidates

PGE's transmission requirements are a hurdle to participating in the RFP because BPA transmission is a limited resource, especially now that BPA has decided not to proceed with the I-5 Corridor Reinforcement Project. Comparing the number of potential projects in BPA's interconnection queue to those that hold the kind of rights required in PGE's RFP demonstrates a stark reality: PGE is able to dramatically limit competition in its RFP simply by including the requirement for firm transmission rights to PGE's system. If PGE were willing to dedicate its transmission rights to successful bidders, more projects in BPA's interconnection and transmission queues would able to compete.

BPA's current interconnection queue includes scores of potential projects in the area. In fact, approximately 7,500 MW of renewable resources are currently listed as having all of their studies complete. An additional 9,500 MW are currently listed as being in active study, and another 1,200 MW have been recently received. Thus, the total

6 Re PGE Request for Proposals for Capacity Resources, Docket No. UM 1535, Order No. 11-371 at 6 (Sept. 27, 2011).

pool of active, prospectively BPA-connected projects that could bid into PGE's RFP if PGE were to make its transmission available to successful IPP bidders is over 18,000 MW.

On the other hand, the number of facilities that have access to the kind of transmission that PGE is requiring may be limited to only six companies. That is because these transmission reservations are expensive to maintain without a long-term purchaser and expose the holders to a certain amount of risk if their intended projects do not materialize. These six companies have only 1,365 MW of transmission available between them.

Comparing BPA's transmission requests indicates that PGE is able to limit prospective bidders ten-fold simply by requiring a limited resource, namely the most expensive type of transmission available over BPA's system. These ratios are only going to get worse because the I-5 corridor is unlikely to see upgrades in the near future. The Commission should reject requirements in renewable RFPs that bidders must deliver to PGE on firm transmission. PGE's limitation undoubtedly excludes potential projects with better shape profiles, better capacity factors, less permitting risks, lower construction costs, or better state tax incentives than PGE's Benchmark Resource.[7] By limiting the amount of competition in its RFP so dramatically, PGE is more likely to impede the selection of the truly lowest cost and risk option.

[7] E.g., current Washington state sales tax provisions may make Washington a lower-cost option than the eastern Oregon facilities PGE appears to be targeting.

3. Allowing Other Transmission Options Could Provide Significant Cost Savings to PGE's Ratepayers

In addition to limiting potentially lower-cost projects, PGE's transmission requirements also impose unnecessary costs on projects that are to participate in the RFP. It is important to note that bidders must provide firm transmission service 100 percent of the time for a renewable resource that may only generate power 30 percent of the time. This means that for upwards of 70 percent of the a PPA bid's term, which could be as long as 20 years, there little or no value for the transmission that PGE requires.

Developers should be allowed flexibility in offering delivery options that combine firm, conditional-firm, and short-term firm transmission capacity reservations. Conditional-firm transmission service, which is curtailed after non-firm but before firm transmission, may provide an equivalent value for the kind of renewable resources that PGE is seeking. To date, conditional-firm on BPA's transmission system has only been curtailed five hours since the service was created over a decade ago.[8] There are also other products that can provide certainty and reliability of long-term firm that could be utilized by bidders.[9] Power marketers may have products that could provide reliability. Even short-term firm transmission, which is the least expensive form of transmission because it is curtailed first to alleviate transmission congestion and ensure reliability, may be appropriate. To be clear, NIPPC is not advocating to allow solely short-term firm, but believes that PGE does not need to be so restrictive here. Requiring remote renewable

---

8 Even though BPA has proposed revisions to its conditional firm product in its Pro Forma Gap Analysis some developers do not believe the changes are likely to increase the amount of curtailments, thus preserving the reliability of the product. BPA is also offering a conditional firm product in the South of Allston process.

9 Puget Sound Energy has proposed something similar in its most recent IRP for Lower Snake Ridge and Hopkins wind farms. See Appendix I, available at https://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx.

resources to acquire long-term firm transmission arbitrarily inflates resource costs and provides no increased reliability benefits.

It is important to consider that PGE's system is contractually constrained, but has a high amount of liquidity.[10] This means that going to the market for some short-term firm sales may not be a risky option. This is especially true when considering PPA bids. IPPs do not get paid for power they cannot deliver and frequently agree to PPAs with severe penalties for failing to meet minimum deliverability requirements. PGE could also develop creative strategies to mitigate delivery risk associated with the use of interruptible transmission products by requiring minimum annual delivery requirements and shortfall penalties that would enable PGE to plan for energy balance and RPS compliance while maximizing utilization of the regional transmission system. These kinds of incentives weigh against developers that might be tempted to take on a risky transmission profile. Because PPAs ultimately protect PGE's ratepayers from risk associated with blended delivery strategies, it may be to the ratepayers' benefit to accommodate delivery to PGE load via a combination of firm, conditional-firm, and short-term market transmission products to achieve the lowest possible delivery cost.

Finally, the additional risk associated with deliveries that do not use long-term firm BPA transmission can be reflected in the price and appropriately valued in the bid scoring process. As this is an energy and not a capacity RFP, ratepayers may be benefited by a significantly lower price with a slightly greater risk of curtailment than a more expensive option that has greater deliverability guarantees. Especially if ratepayers

[10] PGE's transmission strategy, i.e. requiring long-term firm transmission, will exacerbate this contractual constraint.

are held harmless by contract provisions that fully protect them if deliveries cannot be made.

4. Allowing Bidders to Choose Between BPA and PGE's Ancillary Services Would Provide Additional Cost Savings to PGE Ratepayers

In addition to requiring long-term firm transmission, PGE also requires off-system bidders that are metered in a BAA other than PGE's to purchase expensive balancing services from BPA—or at least to embed those costs in their bids. The Commission should require PGE to remove this restriction and allow bidders to take balancing services from PGE or other entities rather than only BPA. This could be achieved by making PGE, rather than the bidders, responsible for providing balancing services.

The responsibility for balancing a renewable generator's real-time output with its scheduled output is the responsibility of the BAA Operator in whose BAA the renewable generator is metered, which may be different than the transmission operator to which the generator has obtained interconnection and transmission. To respond to imbalances, the BAA holds reserves. The cost of holding these reserves can be quite high when generation occurs outside of a generator's efficient operating range and during high-priced market conditions. Off-system projects bidding into PGE's RFP will need balancing services, but do not necessarily need BPA to provide this service. PGE currently procures all of its own balancing services from PGE Transmission Services, including for their own resources that receive transmission over the BPA system. PGE's balancing costs are lower than BPA's and if PGE takes BPA balancing service for any resource, then the resource is ineligible to participate in the Energy Imbalance Market

("EIM").[11] PGE should retain the control over who balances their generating resources over the next 20 years, and should not force bidders to embed the costs of 20 years of resource balancing by BPA in their bids.

For projects that bring firm third-party transmission, or take advantage of firm third-party transmission held by PGE such that the project can be pseudo-tied into PGE's BAA, PGE is a more appropriate balancing service provider than BPA. PGE has invested over $300 million and installed extensive infrastructure to expand its transmission capability and to move PGE's own external renewable resources into PGE's BAA. PGE built the 220 MW Port Westward 2 generator for the express purpose to provide a new flexible capacity resource that would provide lower cost balancing services than typically available in the BPA BAA such that PGE could effectively balance PGE's growing portfolio of renewable generation. The Port Westward 2 plant is a ratebased resource that is being paid for by PGE's ratepayers, and was never approved as a resource that should be used solely by Company-owned generation to the exclusion of potentially more cost-effective competitive IPP resources. Yet PGE appears to intend to only use Port Westward 2 for balancing Company-owned resources located in BPA's BAA. PGE has recently moved 717 MW of Company-owned wind resources from BPA's BAA into PGE's BAA.[12] Instead of reserving the balancing capabilities within PGE's BAA for Company-owned generators, PGE should simply treat any new resources acquired in this RFP the same as its other resources.

---

[11] BPA does not participate in the EIM.

[12] On December 14, 2017, PGE completed the removal of the Tucannon River (267 MW) and Bigelow Canyon (450 MW) wind resources from BPA's BAA and into PGE's BAA via pseudo-tie, see https://transmission.bpa.gov/Business/Operations/Wind/WIND_InstalledCapacity_LIST.pdf.

Notably, PGE has allowed pseudo ties from IPP bidders in a past renewable RFP, and provides no explanation here why the same treatment cannot be used. The 2012 Renewable RFP stated: "PGE will accept bids proposing to deliver intermittent resources via dynamic transfer. Scores for such bids will be based on the full cost of wind integration as identified in PGE's wind integration study."[13] There is no apparent basis for different treatment here.

Moving some or all of the renewable resources acquired through this RFP into PGE's BAA would provide PGE ratepayers with diversity benefits and cost savings from balancing a larger pool of geographically diverse renewable resources. There are cost savings resulting from the diversity benefits of pooling geographically diverse intermittent resources into a single BAA. Resource diversity substantially lowers the cost per MW of balancing intermittent renewable resources because it effectively allows scheduling errors to offset rather than to compound. Having a bunch of similarly situated resources next to each other would require a BAA to have a larger amount of reserves available.

PGE is a participant in the Energy Imbalance Market. Just as there are opportunities for PGE and IPPs to agree to PPAs that allocate transmission risk between the parties, there are now market mechanisms that allow imbalance risk to be allocated between PGE and IPPs. Third parties are willing to provide capacity to meet balancing reserve requirements. Combining market prices for imbalance energy and accepting a higher level of curtailment risk may prove more cost effective for PGE ratepayers than purchasing imbalance energy at cost based rates from BPA.

---

13 PGE Request for Proposals for Renewable Resources, OPUC Docket No. UM 1613, PGE Revised Draft RFP at 26 (Sept. 10, 2012).

PGE should compare, however, the potential cost savings associated with diverse resource integration with monthly, daily or hourly firm renewable energy from bidders electing to obtain BPA's balancing services, and in particular those using a combination of firm and short-term firm transmission resources to delivery their energy. PGE should not compel all bidders to procure BPA balancing services. Just as with firm and conditional-firm, developers should have the flexibility to design their bids creatively, so that they can provide lower cost and risk options.

As is, PGE's requirement that PPA bidders (but not utility-ownership bidders) provide BPA balancing services is overly restrictive and exposes PGE ratepayers to unnecessary costs. The Commission should expect PGE to make every effort to move any resource acquired through this RFP into its own BAA to capture these obvious cost savings, and should therefore direct PGE to accept bids that deliver energy firm but unbalanced. For proposals that bring their own transmission resources or elect to make use of PGE's transmission portfolio, PGE can add resource-specific costs during bid evaluation. For proposed resources that cannot be moved into PGE's BAA via pseudo-tie and balanced by PGE transmission services, PGE should substantiate and document the unique reasons, e.g., delivery relying in part of market transmission.

5. PGE Should Provide More Transparency Regarding its Benchmark Resource Bid

PGE should publish the escalation factor assumed by PGE's Benchmark Resource to establish a more level playing field among bidders. Because PGE's RFP requires bidders to provide transmission service for extended periods, 10 or 20 years, PGE should provide transparency about its transmission assumptions. For example, if IPP bidders are forced to provide expensive BPA transmission service over the term of the PPA bid, then they must make certain assumptions about how much those rates will escalate. Some developers may be tempted to assume a low escalation factor to make their bid more competitive, but that risk is assumed by the developer and is not passed on to PGE ratepayers. If PGE were similarly tempted to assume a low escalation factor, however, that risk would ultimately be borne by its ratepayers. PGE has stated that its Benchmark bid will provide the same kind of transmission services required of other bidders. It therefore makes sense for PGE to publish its escalation rate so that PPA bids can ensure they are competing on a level playing field. Allowing PGE to assume a 2% factor, while IPP bidders are assuming 4% would not lead to an equitable comparison of what should be the same baked-in transmission product.

B. PGE's Public Utility Regulatory Policies Act ("PURPA") Limitations Should Be Removed From this RFP

PURPA should not be relevant in this RFP, and would not be if PGE had not used the occasion to discriminate against PURPA qualifying facilities ("QFs"). PGE's first draft of this RFP aggressively proposed that PURPA bidders not be eligible to participate.[14] This proposal was consistent with PGE's efforts to penalize any developer from exercising their rights to sell power under PURPA. PGE's restriction makes it clear to developers that, if they seek a PURPA contract, then PGE will simply not purchase power from them in other contexts, including bi-lateral negotiations or RFPs. PGE's public and private position is that developers need to pick one of two options (either a PURPA contract or the RFP), neither of which have much of a history of success.

---

[14] PGE's Pre-Issuance Draft RFP at Section 6.1.5 (Feb. 23, 2018) ("[b]idders with standing QF status … are invited to bid … [h]owever, bidders who have executed a contract with PGE or are actively negotiating a contract under Schedule 202 are not eligible to participate in the solicitation").

After receiving pushback from stakeholders in a workshop, PGE filed its current draft RFP with clarifying language that states that PGE's intent is not to preclude PURPA *bidders* from its RFP, just PURPA *projects*. This is also not acceptable and violates the Commission's competitive bidding guidelines, which state that: "The utility may set a minimum resource size, but Qualifying Facilities larger than 10 MW must be allowed to participate."[15] In addition, PGE's Schedule 202 governing the process for larger QF contract negotiations includes no restriction on the ability of a QF from also bidding the same project into an RFP. The Commission should direct PGE to modify its RFP to be PURPA-agnostic and specifically direct the Independent Evaluator ("IE") to monitor any PURPA project bids to police against PGE discriminating against QFs. This is an important issue for this RFP because, given the limited number of entities who can purchase power, many of the same developers that would bid into the RFP are likely also seeking PURPA contracts with PGE. Excluding these resources and sites could significantly narrow the options available in the RFP.

1. Both QF Bidders and QF Bids Should Be Allowed to Participate

First, Section 6.1.5 provides PGE's clarified language that QF bidders are eligible to participate in PGE's RFP, but that QF projects are not. PGE's RFP states, "Bidders with projects that have an executed contract with PGE or are actively negotiating a contract under Schedule 202 are not eligible to bid the project in this RFP."[16] PGE suggests that a QF would need to either terminate its contract or withdraw from its Schedule 202 negotiations jut to bid into this RFP. This is objectionable and should be revised.

---

15 Competitive Bidding Guidelines § 6.

16 PGE 2018 Draft RFP § 6.1.5.

To begin with, PGE wants to prevent QFs with executed Schedule 201 contracts from bidding their projects into PGE's RFP to secure a more favorable PPA or better regulatory treatment from PGE. NIPPC fails to understand the problem with a QF that is already under contract with PGE from providing PGE with a lower cost or less risky option. If QFs with executed Schedule 201 contracts wish to submit their projects into PGE's RFP, and those terms, prices and conditions are more favorable to PGE and its ratepayers, then why should PGE turn those away?

There is no public information about how many potential bidders are actively negotiating a contract under PGE's Schedule 202. But even a cursory glance at RE 143, where PGE posts its PURPA contracts, demonstrates the difficulty of negotiating a contract with PGE as only one QF has successfully negotiated a Schedule 202 contract with PGE.[17] Negotiating a Schedule 202 contract is a difficult, time consuming process, and (almost) impossible. Despite this, NIPPC expects that many developers may be in the Schedule 202 negotiation process with PGE simply because there are few other options to sell their power.

PGE would require these developers to choose between a Schedule 202 process or a successful RFP bid. Instead of limiting their options, any developer should be encouraged to pursue as many business opportunities as possible, especially with the same power purchaser. The only reason that a larger QF that is currently negotiating with PGE should need to withdraw from those negotiations would be to narrow the potential options in PGE's RFP and penalize QFs that attempt to negotiate PURPA contracts.

---

17 See Docket No. RE 143, available at http://apps.puc.state.or.us/edockets/docket.asp?DocketID=19098.

2. IPPs Should Not Be Asked to Waive Their PURPA Rights

PGE's RFP also requires bidders to agree to waive their future PURPA rights. Section 5.8 states that if the winning PPA is terminated due to the Seller's default, and that default has been remedied after the termination, neither the Seller nor any of its affiliates associated with the same site "may thereafter require or seek to require PGE to make any purchases from the Facility or any electric generation facility constructed on the Site under PURPA . . . for any periods that would have been within the Term had this Agreement remained in effect." This means that if PGE terminates the winning contract, receives its damages, which theoretically makes PGE whole after the default, then PGE will then not allow *anyone* at the site to apply for a PURPA contract during the terminated contract's full term. PGE therefore expressly requires QF bidders to waive PGE's mandatory purchase obligations and, thus, their own PURPA rights.[18] According to PGE's draft PPA:

> On or before the Effective Date, the Parties shall execute and record, in the appropriate real property records of the counties in which the Facility or Site is situated, and any federal agency as applicable, a memorandum in form acceptable to PGE to provide constructive notice to third parties of Seller's agreements under this Section 5.8. In no event will PGE be required to make any purchases from the Facility or any electric generation facility constructed on the Site in the event the default that caused the termination is still in effect.[19]

This provision appears to conflict with Federal Energy Regulatory Commission ("FERC") guidance on PURPA, which has expressly prohibited any contractual interference with a QF's PURPA rights. FERC has made clear that contracts should not be allowed to override the obligation to purchase from QFs, and thus, that a utility may

---

18 PGE 2018 Draft RFP at Appendix A at Section 5.8 ("Seller … hereby waives its rights to require PGE to do so").

19 Id.

not contractually sign away a QF's PURPA rights.[20] The PURPA provision in PGE's RFP appears to be anti-competitive, discriminatory, unfair, and inconsistent with FERC guidance. PGE's proposal to record such restriction on the real property goes even a step further and unlawfully burdens real property in the state with these restrictions. The Commission should therefore instruct PGE to revise its RFP to remove these ridiculous PURPA provisions.

A more appropriate requirement would be similar to that contained in PGE's standard PURPA contract forms, which limits any subsequent contract to the avoided cost rates in effect at the time of contract execution.[21] It is reasonable to prevent a developer from benefiting from its own default by capping the prices in their new contract to no more than those in the original contract. But a complete bar on new contracts and burdens on real property rights is both illegal and would unreasonably limit the pool of potential renewable energy sellers willing to bid into this RFP and from selling power to PGE in the future.

---

20 Delta-Montrose, 151 FERC ¶ 61,238 (2015); Pub Serv. Co. of N.H. v. N.H. Elec. Coop. Inc., 83 FERC ¶ 61,224, at 61,998- 99 & n.9 (1998).

21 PGE Standard In-System Variable Power Purchase Agreement Section 9.5 ("In the event PGE terminates this Agreement pursuant to this Section 9, and Seller wishes to again sell Net Output to PGE following such termination, PGE in its sole discretion may require that Seller shall do so subject to the terms of this Agreement, including but not limited to the Contract Price until the Term of this Agreement (as set forth in Section 2.3) would have run in due course had the Agreement remained in effect. At such time Seller and PGE agree to execute a written document ratifying the terms of this Agreement.") available at https://www.portlandgeneral.com/business/power-choices-pricing/renewable-power/install-solar-wind-more/sell-power-to-pge.

C. PGE Should Develop a Short-List that Includes at Least 150 Average Megawatts ("aMW") of Non-Benchmark Resources and Should Also Not Include Generic "Fill" for Portfolios Less than 100 aMW

PGE is using the concept of generic "fill" to provide an advantage to any resource that is 100 aMW, which happens to be the same size as its Benchmark Resource. PGE will develop a short-list that will be a minimum of 150 aMW.[22] In developing the final short-list, PGE will conduct a portfolio analysis to provide the Company with additional information regarding cost and risk profile to determine how the resources perform as a group.[23] In each portfolio, PGE will include resources to meet the targeted renewable volume of 100 aMW, and any individual "portfolio whose forecasted energy volume does not meet the targeted renewable volume will also include a specified fill resource ("fill")."[24] PGE is only performing portfolio analysis for groups of resources of 100 aMW, and does not intend to perform portfolio analysis on smaller targeted volumes (e.g., 50 aMW or 75 aMW) that more closely match the size of non-Benchmark Resource bids.

PGE's limitation in the size of the short-list to 150 aMW is too low. NIPPC expects that PGE's Benchmark Resource of 100 aMW will make it to the short-list, which means that there may only be an additional 50 aMW, if the short-list is limited to 150 aMW. The short-list should not essentially be limited to a little more than PGE's Benchmark Resource but should include at least 150 aMW of non-Benchmark Resources.

PGE's proposal to use generic fill will disadvantage any bids that are less than the full 100 aMW. For a portfolio that includes less than 100 aMW (which necessarily

---

22 PGE 2018 Draft RFP § 9.
23 Id.
24 Id.

would be non-Benchmark Resources), PGE is likely to assume a higher cost generic resource to fill the remainder of the target. For evaluation purposes, this will drive up the cost of portfolios without Benchmark Resources.[25] The practical result is that many bids that are lower cost than PGE's Benchmark Resource may be disqualified, solely because they were too small individually and in aggregate to meet the full 100 aMW target. This will have a larger penalty for solar projects, which are unlikely to bid in exact 100 aMW project sizes.

D. PGE's Credit and Bidder Qualifications May Unnecessarily Disqualify Smaller Developers

This RFP should provide realistic opportunities for both small and large developers to submit bids, and should be structured to ensure that no type of bidder is barred merely because of its smaller size. As structured, this RFP will likely be limited to PGE's own Benchmark Resource and only those major developers that have ready access and financial resources. This will unnecessarily limit the pool of developers.

PGE's RFP states "[t]o be eligible for bidding a Bidder must . . . demonstrate an ability to secure necessary pre-COD performance assurances in the form of a letter of credit from a qualified institution."[26] While this may not be unduly burdensome for larger developers, this prevents smaller companies with excellent track records of constructing small to mid-size projects from submitting bids. Instead of a letter of credit, bidders should be allowed to post a power purchase agreement security. This should be

---

25 As an example and using hypothetical numbers, there can be a portfolio of non-Benchmark Resources that cost $40 MWh, but that only meet 60 MW of PGE's 100 aMW target, compared to PGE's Benchmark Resource that costs $50 MWh. However, to equate the two portfolios, PGE will add a generic 40 MW $65 MWh resource to the non-Benchmark Resource portfolio resulting in a portfolio appears more expensive than PGE's Benchmark Resource.

26 PGE 2018 Draft RFP § 6.1.4.

sufficient, especially since PGE already requires that bidders that do not finance the project themselves must "provide evidence of a good faith commitment from a financial institution or lender prior to placement on PGE's final shortlist."[27]

E. PGE Should Take Advantage of Declining Costs

Renewable resource costs are rapidly declining due to technological advances, and significant or unexpected changes in government policy can impact the economics of any project. PGE and its ratepayers should be able to take advantage of any cost declines through the RFP by allowing bidders to update their pricing to reflect cost reductions. PGE's RFP states, however, that "Bidders may not update pricing during the scoring and evaluation period."[28] This restriction is not required, as the Commission's competitive bidding guidelines allow for bidder updates if appropriate.[29] Therefore, the Commission should direct PGE to revise the RFP to allow, at an appropriate pre-determined time, the bidders to update their bids with any cost reductions.

F. A PPA Bidder Should Have the Option for PGE to Retain Control Over the Resources' Scheduling, Dispatch, Transmission and Balancing

PGE ratepayers deserve to benefit from the lowest-cost resources regardless of ownership. NIPPC recommends that a bidder have the option of allowing PGE the ability to integrate the resource into PGE's system, and to make operating decisions throughout the life of the resource. This could reduce PGE's ability to discriminate against PPA bidders by imposing burdensome scheduling requirements as well as maintain or enhance the ratepayer value of each resource when integrated into PGE's

---

27 Id. § 6.2.3.
28 Id. § 7.1.
29 See Competitive Bidding Guidelines § 8 (stating that if the utility, with input from the IE, determines that bidder updates are appropriate, then the utility may also update the costs and score for the Benchmark Resource).

resource portfolio. To do so, PGE will need to ensure the contractual terms underlying any resource acquired give PGE the ability to adapt the deployment of each resource to changing market conditions and regulatory structures over the life of any resources acquired.

NIPPC makes this proposal for three reasons. One, PGE's RFP includes onerous provisions regarding scheduling of power deliveries which will have the practical impact that any bidder that schedules appropriately will not be paid the full contract price, regardless of how accurately they schedule and operate their facility. Two, PGE will have control over the scheduling, dispatch, transmission and balancing of its own generation, which provides unique costs and benefits for utility owned generation that are difficult to quantify and properly evaluate against PPA bids. Providing the PPA bidder the option to have PGE maintain this control may mitigate the advantage the utility owned bids have. Finally, and most importantly, ratepayers will obtain significant benefits because PGE will have the ability optimize the use of all its resources for balancing, integration and participation in the EIM.

1. The Draft PPA Imposes Onerous Scheduling Requirements on PPA Bids

PGE's scheduling and compensation requirements for off-system, non-utility bidders are unreasonable and discriminatory. In PGE's 2016 RFP, NIPPC spent considerable effort attempting to rectify contract provisions that did not allow PPA bidders to be fully paid for all electricity generated and delivered.[30] Similarly, PGE's

---

[30] Re PGE Petition for Partial Waiver of Competitive Bidding Guidelines and Approval of Request for Proposals (RFP) Schedule, Docket No. UM 1773, NIPPC Comments at 6-13 (June 6, 2016); Docket No. UM 1773, NIPPC Final Comments at 11-17 (July 27, 2016).

dispute with payments and scheduling of a 9.9 MW off-system qualifying facility resulted in the FERC requiring PGE to pay the small non-utility generator for all their generation delivered and undelivered.[31]

In this RFP, PGE proposed a new concept of "Specified Amounts" and "Specified Energy".[32] NIPPC provides a full critique in Attachment A to these comments, but in summary PGE's approach will result in a PPA project: 1) never earning the full PPA price for actual generation that exceeds a forecast of average generation; 2) being unable to make up scheduled deviations where the project generates less than the amount scheduled and delivered; and 3) never earning the PPA price for all actual project generation, even if the actual project matches schedules. There will be no good years for the PPA Seller, as PGE will only pay the PPA price for the lesser of average forecasted output or some fraction of actual project output. The practical result is that a PPA bidder cannot accurately project how much revenue they will obtain, and the bidder will need to increase its price to reflect this unknown and unnecessary risk.

2. The Discrimination Against PPA Bids Can Be Removed and Ratepayers Benefited with Additional Cost Savings and other Benefits, if PGE Retains Control Over the Scheduling, Dispatch, Transmission and Balancing of PPAs

To retain sufficient control over resource operations, a bidder should have the option for PGE to retain the rights to resource scheduling, procurement of the lowest cost balancing services, and the ability to modify transmission arrangements over the life of the resource. This could be accomplished by establishing a point of delivery in the PPA at the busbar at the point of interconnection to the interstate grid as opposed to the point

31 PaTu Wind Farm LLC v. PGE, 151 FERC ¶ 61,223 PP. 46-51 (2016).
32 PGE Partial Waiver of Competitive Bidding Guidelines, Docket No. UM 1773, PGE 2018 Draft RFP, PPA § 1.1.118 and 1.1.119 (May 12, 2016).

where the energy first enters PGE's transmission system. This is a common arrangement in PPAs with utilities, which will often have a portfolio of transmission resources to more cost effectively delivery the power to load or market and a cheaper in-house capability to schedule the power. PPA bidders should have the option to assign these operating rights to PGE. This would result in PGE retaining scheduling authority for PPA projects so that PGE ratepayers can capture the efficiencies of PGE's scheduling function, which is currently engaged in scheduling all of PGE's renewable resources and optimizing the scheduling and integration of those resources into PGE's total resource portfolio while maximizing EIM benefits.

As currently structured, PGE proposes to voluntarily give up operating rights by specifically assigning them to the PPA bidders. Notably, PGE's approach is inconsistent with PacifiCorp's form PPA included in its recent RFP, in which PacifiCorp, and not the PPA bidder, is responsible for balancing the resource and paying any balancing charges or penalties.[33]

PGE's approach harms ratepayers in two ways. One, PGE does not have the flexibility to control and manage the costs and operational logistics of integrating the resource into their power system today and over time. Two, PPA bidders are forced to embed costly services into their bid price that PGE can self-supply now, and manage over time, at lower cost and risk to ratepayers than can the PPA bidder.

---

[33] PacifiCorp RFP PPA App E-2 §§ 5.2 (Costs and Charges) and 6.6 (Scheduling) ("PacifiCorp shall be responsible for all costs or charges, if any, imposed in connection with the delivery of Net Output at and from the Point of Delivery, including transmission costs and transmission line losses and imbalance charges or penalties."), available at http://www.pacificorp.com/sup/rfps/2017-rfp/2017R_RFP_Doc_and_Appendices.html.

3. NIPPC's Specific Recommended Revisions to PGE's Draft PPAs

First, PGE should remove the proposed RFP obligation placed upon PPA bidders to perform the resource scheduling function over the term of any PPA. Instead of PPA bidders performing the scheduling function, the PPA bidder should have the option for this scheduling requirement to be removed from the PPA as an obligation of the PPA bidder. In its place, provisions should be added that explicitly state that PGE will schedule the resource, and PGE will impose requirements on any PPA bidder must fully cooperate with PGE schedulers and BA dispatchers.

An added benefit of this change is that it will achieve consistency between the evaluation of the IPP –owned and utility-owned resources because PGE will be assumed the scheduling agent for all resources acquired through the RFP. This will simplify the evaluation process because PGE will not have to include a non-price penalty to utility-owned resources to reflect PGE's internal costs and ratepayer exposure to PGE scheduling errors resulting from PGE's scheduling its Company-owned resources; a non-price factor missing from the current evaluation framework.

Second, PGE should modify the RFP to allow PPA bidders to price their bids without embedding the cost of third-party balancing services in their bids. PGE can add the appropriate balancing costs to each PPA bid respectively in the bid evaluation itself. This change will have the following benefits:

- PGE will not need a non-price adder to utility owned projects due to scheduling and balancing each utility-owned resource in the evaluation process because PGE will be performing all the operating functions for all ratepayer resources, whether utility owned or PPA.
- PGE will attract lower cost and more competitive bids if PPA bidders are not required to include uncertain future cost obligations in their bid that they cannot control.

- PGE ratepayers will achieve the benefits outlined in the above transmission by removing the requirement that PPA bidders acquire third-party balancing services and embed the costs in their bids. These benefits include PGE ability to optimize resource balancing costs in the future by shifting balancing services to PGE transmission with the associated benefits of participation in the EIM.

To achieve this result, PGE should eliminate the provision in the proposed RFP that requires PPA bidders to bundle the cost of 20 years of balancing services into their project bids. The draft PPA should only require PPA bidders to deliver all project output over firm transmission as it is generated. This will attract more competitive bids, and equate the treatment of PPA projects with utility-ownership projects, which are not required to embed 20 years of balancing costs in their bids.

G. Projects Should Not Be Required to Have a Completed Interconnection Agreement to Reach the Short-list

PGE's proposed interconnection timelines will prevent otherwise viable projects from being considered on the short-list. PGE proposed that, in order to submit its bid, the bidder must have executed a System Impact Study Agreement.[34] NIPPC does not object to this requirement. However, the RFP then states that "[b]idders that have not completed an Interconnection Study Agreement prior to placement on PGE's Final Shortlist will be deemed unready for construction and will be disqualified from the evaluation."[35] First, NIPPC assumes that PGE means "Interconnection Agreement" rather than "Interconnection Study Agreement." Second, and more important, there may be insufficient time between the submission of the bid and the selection of the short-list to allow a bidder that has executed the System Impact Study Agreement to complete the

[34] PGE 2018 Draft RFP § 6.2.7.
[35] Id.

Interconnection Agreement.[36] Therefore, this requirement should be changed or clarified by PGE so that a bidder only needs to enter into a Facilities Study Agreement to reach the short-list. In addition, if there are delays outside of the bidders control that are caused by the transmission provider (e.g., BPA), then that will not prevent the bidder from being placed on the short-list.

For those not familiar with the FERC-jurisdictional interconnection process, the first step can be either a Feasibility or System Impact Study. The developer and the interconnected utility enter into an agreement to conduct the study, which is called a "System Impact Study Agreement." This study has timelines for payment by the developer and completion of the study by the utility. After the developer and utility enter into this agreement to conduct studies, then the utility conducts the study and reviews the adequacy of its transmission system to accommodate the new generation and what additional costs may be incurred to provide service. At the completion of the System Impact Study, then the developer and the utility must enter into a new contract to conduct a new study, which is the "Facilities Study Agreement". The Facilities Study Agreement also includes timelines for payment and the completion of the study. The Facilities Study itself is more granular and is a real engineering study designed to determine the required modifications to the system, including the cost and scheduled completion date necessary to provide service. After these timelines and costs are identified in the Facilities Study, then the utility and developer negotiate an actual Interconnection Agreement to construct and pay for the interconnection to the utility's system.

---

[36] PGE proposes that bids will be due by June 15, 2018. PGE Draft RFP § 2. The short-list analysis is expected in August and September 2018. PGE 2018 Draft RFP at Appendix A at "RFP Timeline" (March 28, 2018).

The process, even when moving perfectly, can be cumbersome and time consuming, and it is not uncommon for there to be significant delays completely outside of the control of the developer. This may be especially true for studies conducted by utilities that are not subject to FERC's interconnection jurisdiction, like BPA. Given the time and difficulty between the early step of the System Impact Study Agreement and the actual Interconnection Agreement, it is not reasonable to expect that all bidders will be able to obtain an Interconnection Agreement by the time of being moved to the short-list. Therefore, NIPPC recommends that to reach the short-list, a bidder need only have entered into a Facilities Study Agreement with a reasonable timeline that will allow for an Interconnection Agreement by the time that the Commission acknowledges the short-list and PGE begins final contract negotiations.

H. PGE's 30-year Plus Portfolio Net Present Value of Revenue Requirement ("NPVRR") Is Too Long

PGE's short-list portfolio analysis will calculate the total NPVRR for the years 2018 to 2050 under each future "to estimate the cost impacts of the additions on PGE's system."[37] Such a long-term analysis does not account for the benefits of shorter contract terms of PPAs versus a rate-based facility. For example, such a long term of evaluation of the costs and benefits will overweigh the near-term savings because of the discounting of value of future benefits relative to the near term benefits of the Production Tax Credits ("PTCs").

NIPPC is concerned that PGE will not correctly evaluate the actual costs for comparison purposes between a longer-term obligation placed in rate base (30-plus years) and the shorter-term PPA (15-25 years). Generally speaking, a PPA option will typically

[37] PGE 2018 Draft RFP § 9.

be far less expensive to the ratepayer in the early years and a utility-owned resource declines in costs in its later years (if the utility-owned resource costs and performs as advertised in those future years).

Additionally, the utility resource is placed in rates for a period that is typically far in excess of the term of the PPA bids, and thus the RFP that compares these two different resource types must conduct present value and/or levelization analysis. This is because PGE must make assumptions regarding the costs of power during the years in which the shorter-term PPA expires, but the utility owned resource is still included in rates. Typically, a utility will include a generic fill for the costs assumptions in which the PPA actual price is substituted for some utility assumed price. This analysis is inherently flawed since one type of bid (PPA) provides a known price while the other requires extensive assumptions to develop an assumed price. Consequently, this is an area where major errors can be made or unreasonable assumptions drive resource decisions.

NIPPC recommends that the IE review this issue and provide a recommended solution in its initial report. Then, Staff, the parties and the Commission can evaluate that recommendation prior to acknowledgment of PGE's RFP.

I. PGE's Requirement that Bidders to Provide Confidential Quotes, Commitments, or Documentation of Purchase for PPA Bids Appears To Be Anti-Competitive

PGE asks bidders to provide private, commercial pricing information that PGE could use to gain a competitive advantage. Because PGE is planning to enter a Benchmark bid, all of the other bidders are effectively PGE's competition in this RFP. This makes PGE's request for confidential information very suspect. The Commission frequently allows the utilities to aggressively protect their own commercial information and should do the same for IPPs now. Requiring bidders to share confidential commercial information is likely to have a chilling effect, and the Commission should protect bidders' commercial information.

PGE requires IPPs to provide confidential equipment costs. Section 6.2.5 requires all bidders to provide, "a quote commitment, or documentation of purchase from a wind turbine, photovoltaic panel, or steam turbine manufacturer."[38] This kind of request may be reasonable for ownership-transfers, but it is not reasonable for PPA bids. PGE can evaluate PPA bids without knowing their equipment costs or the deals they are able to negotiate with contractors. Yet, the RFP expressly states this is an eligibility requirement for all bidders.[39]

This same section goes on to include additional requirements for utility-owned projects, which begs the question—why are there two standards? For utility-owned projects, Section 6.2.5 requires bidders to include Engineering Procurement and Construction quotes and notes that the bid price must be reflect the equipment and contractor costs. These additional limitations indicate that PGE agrees with NIPPC that different levels of scrutiny are appropriate depending on ownership type. Rather than requiring all bidders to provide equipment costs and utility-ownership bids to provide additional information, this section of the RFP should be limited to utility-ownership bids in its entirety.

J. The Damages Cap Should Be Removed or Significantly Increased

Once again, PGE proposed that bidders sign an unreasonable Confidentiality and Non-Disclosure Agreement ("NDA") that inappropriately limits the damages that a

---

38 PGE 2018 Draft RFP § 6.2.5.
39 Id.

bidder can recover from PGE's illegal actions, including the theft of trade secrets to only $100,000. PGE's damages cap will result in bidders being more reluctant to provide detailed information, especially regarding new and cutting edge technologies or designs that could provide significant savings for ratepayers. Essentially, if PGE steals or otherwise misappropriates or uses any confidential bidder information, PGE's RFP will provide no meaningful opportunity for the bidder to seek recourse for its damages. PGE should be required to either remove the cap, or significantly increase the damages cap to $150 million.

PGE proposed and removed a damages waiver cap in its last couple RFPs. PGE's original NDA in the 2012 Renewable RFP did not include a cap on damages, but PGE filed a revised RFP adding a new $100,000 cap on liability shortly after the initial filing.[40] PGE quickly withdrew the cap, acknowledging that parties had not had an opportunity to develop the record regarding that change.[41] In its 2016 Renewable RFP, PGE originally proposed a $100,000 damages waiver cap for breaches of the NDA.[42] After objection from NIPPC, PGE withdrew its requested damage waiver cap.[43]

This cap is far too low considering the type of information PGE is soliciting. As NIPPC has previously explained, the Supreme Court of Utah affirmed a jury award of more than $133 million to compensate a developer for the loss of this exact type of

---

40 Re PGE Request For Proposals for Renewable Resources, Docket No. UM 1613, PGE Revised RFP For Renewable Energy Resources (Sep. 10, 2012).

41 Re PGE Request For Proposals for Renewable Resources, Docket No. UM 1613, PGE Revised Appendix K (Sep. 19, 2012).

42 Docket No. UM 1773, PGE 2016 Draft RFP at Appendix K § 11 (May 13, 2016)

43 PGE Partial Waiver of Competitive Bidding Guidelines, Docket No. UM 1773, PGE 2016 Revised RFP at 10-11 ("PGE has removed the damages cap in Section 11").

information.[44] In May 2012, a Utah jury found that PacifiCorp "willfully and maliciously misappropriated a trade secret from USA Power . . . ."[45] PacifiCorp was found to effectively mirror a developer's bid in its RFP process, which resulted in PacifiCorp awarding itself the winning bid and building the power plant without the participation of the developer that originally proposed the project.[46]

PGE's proposed damages cap will deter bidders from proposing any cutting-edge technologies or novel approaches that could provide ratepayers with substantial savings. No monopsony buyer that is also a "competitor" with its suppliers should be able require its competitors to waive basic legal protections for the privilege of proposing a power sale. Instead, PGE should be required to comply with the law, not to require those who deal with it waive their legal rights.

K. PTC Certification is Unnecessary

Along these same lines, PGE requires additional information for bids hoping to secure the federal PTC, which are equally inapplicable to PPA bids. Section 6.2.6 applies to "[o]ffers that intend to utilize PTC federal tax credits" and requires these bidders to "demonstrate the project's eligibility" via a narrative description. In addition, PGE requires "a tax opinion from a qualified tax expert to further substantiate the bidder's plan to generate PTCs."[47] This requirement may be reasonable for certain kinds of bids, build-transfers for example, but is not reasonable for PPA bids.

Much was made of the PTC phase-out in PGE's integrated resource plan ("IRP"), and a brief recap of this issue is warranted here. In PGE's IRP, stakeholders questioned

---

44 USA Power, LLC v. PacifiCorp, 2016 UT 20, (2016).
45 Id.
46 Id.
47 PGE 2018 Draft RFP § 6.2.6.

whether PGE had the tax liability to take full advantage of the PTCs and whether PGE had included carrying costs in its estimates.[48] NIPPC pointed out that IPPs could use the PTC benefits, and pass those savings along to PGE's ratepayers, without the need to analyze eligibility or the impacts of carrying costs, because the savings were baked-in to the PPA cost.

When considering Section 6.2.6, it is important to remember that the tax credits are forecasted and dependent upon both the projects' initial investment and ongoing output. To qualify for the PTCs, projects must first meet the Internal Revenue Service safe-harbor provisions (by making a timely investment) and then must actually produce energy over the next ten years. If both of those conditions are met, then the facility owner is eligible to receive ten years of federal tax credits based on the project's output.

This means that if PGE intends to own the project, then it makes sense that PGE would want to ensure that the project is able to meet the initial eligibility deadline, which is rapidly approaching. It is not, however, reasonable to require PPA bidders to speculate as to the availability of the tax credits, as any tax credits will accrue to the owners of a PPA project directly, and to PGE ratepayers indirectly through the bidder's price proposal. As the PPA bidder will be embedding the value of any PTC's into their bids in the form of a much lower guaranteed bid price, PGE ratepayers receive the guaranteed benefits of the PTC when buying from a PPA bidder, and ratepayers are not subject to any PTC risks. In short, PGE does not need to know to this level detail the assumptions concerning PTCs that are embedded in the bids.

---

[48] Re PGE 2016 IRP, Docket No. LC 66, ICNU's Comment at 16 (May 12, 2017).

On the other hand, in cases where PGE is not the intended owner, this requirement is even more dubious. In the case of a PPA bid, for example, there is no reason for the IPP bidder to provide PGE with a tax opinion confirming its eligibility to utilize the PTCs. PGE essentially asks IPPs to provide confidential information about their tax status that has no bearing on PGE at all. PGE would not have any tax implications if it selected a PPA bid, and has no business enquiring about the IPP's tax implications.

Appendix A of PGE's RFP provides a PPA template that expressly confirms, "Seller shall bear all risks, financial and otherwise throughout the Term, associated with Seller's or the Facility's eligibility to receive PTCs, ITCs or other tax credits" meaning that PGE has no tax risk if a PPA bid wins the RFP.[49] This tax opinion imposes additional costs upon PPA bidders and is an unneeded barrier to entry in an RFP with a very tight timeline. PGE's tight PTC timeline is a problem of its own making and should not be used to impose unnecessary burdens on PPA bidders.

L. The Prohibition on Future Capital Additions is Overly Restrictive

PGE's draft PPA also includes onerous restriction on future capital investments to the winning bid that must be revised. Section 3.8.6 of the PPA states "Seller shall not increase … the Facility's ability to deliver Facility Output … Nameplate Capacity, or … Net Available Capacity through any means, including but not limited to replacement or modification of related infrastructure."[50] This provision precludes IPPs from increasing its capacity or output, even when repairing or replacing broken equipment.

---

49 PGE 2018 Draft RFP at Appendix A at 3.1.16.
50 Id. at Appendix A.

This language unnecessarily binds IPP owners from making business decisions or undergoing facility upgrades on their own projects and at their own expense. Replacement and repair are inevitable at all facilities. Utilities and IPPs alike undergo capital replacements under a variety of circumstances and IPPs should be free to choose among options that may be necessary to continue to meet performance guarantees. There is no reason why a contractual agreement to provide a certain amount of power at a certain price should provide PGE this much leverage over a project owner's facility operations or limit their ability to make upgrades.

M. Damages and Termination Provisions are Too Severe

PGE's draft PPA includes a host of provisions that allow PGE to collect damages should a Seller default, but some of its damages provisions go beyond securing the benefit of PGE's bargain and should be revised.[51] Taken as a whole, these provisions allow PGE to go beyond recovering any amounts owed under the contract and allow PGE to over-collect for potentially reasonable delays, withhold its own payments due under the contract, and unreasonably control the facility owner's options after termination.

1. Damages Need Not Be Draconian

At first blush, some of PGE's provisions appear reasonable if clarified. For example, Section 3.1.11 of PGE's draft PPA includes Delay Damages that accrue from the scheduled commercial operation date to the date the facility actually achieves commercial operation. This provision seems generally acceptable, but if the scheduled commercial operation date is amended by the parties, it should not be used to calculate damages. PGE should therefore simply clarify this language accordingly.

[51] Id. § 8.3 (Direct Damages); id. at § 8.6 (Liquidated Damages); id. at Appendix A (Contract Termination Damages, Delay Damages); id. at Article 5.

On the other hand, Section 3.1.12 includes Contract Termination Damages that allow PGE to terminate a winning PPA if the facility misses its commercial operation date by only 10 days. Even worse, it requires the facility to pay PGE $200 per kilowatt ("kW") of the facility's nameplate capacity. Because PGE is seeking 100 average megawatts ("aMW") in this RFP, it could get a PPA with a 300 megawatt ("MW") facility. This means that a 10-day delay could cost that winning PPA bid $60 million in damages to PGE.[52] This is far less acceptable and therefore must also be amended to provide a more reasonable estimate of PGE's damages. This would be an unlawful liquidated damages penalty if it is not tied to likely actual damages. Given recent declines in renewable energy costs, PGE may even be better off in the case of termination of the winning bid, and therefore this liquidated damages clause is not reasonable. It is hard to imagine PGE agreeing to refund $60 million to ratepayers for a 10-day delay in bringing a Company-owned resource online under any circumstances.

Still worse are the provisions in Article 5 of PGE's draft PPA that allow PGE to declare Early Termination. Section 5.2.1 of PGE's draft PPA allows PGE to "liquidate, terminate, and accelerate all amounts owing between the Parties … withhold any payments due … and … suspend performance."[53] This section can be triggered by any Event of Default, defined in Section 5.1, including the failure to deliver for more than five consecutive days or ten days in a year, the failure to meet Minimum Annual Volume deliveries or minimum Mechanical Availability Percentage, the failure to make any payment that is not remedied within ten business days, becoming Bankrupt or going

52 300 MW = 300,000 kW x $200 = $60 million.
53 PGE 2018 Draft RFP at Appendix A.

through a Merger Event. None of these remedies include PGE's treatment of Specified Energy.

2. Right of First Offer Impermissibly Binds IPP Bidders

PGE's draft PPA provides a creative addition to its damages and termination section that is far from reasonable. Section 3.1.15 provides PGE a Right of First Offer upon Termination under Section. 3.1.12, if the seller is ten days late achieving its commercial operation date. This means that should PGE select a PPA bid that is ten days late becoming operational and PGE terminates the contract, then Section 3.1.15 precludes that seller from marketing or delivering any of its power to any other buyers for two years. PGE's Right of First Offer provision would effectively allow PGE to force the PPA seller to re-contract with PGE, presumably at a lower price.

N. Generators Should Be Allowed to Use Industry Standard Data to Forecast Generation Output

PGE requires bidders to justify their forecasted energy deliveries, which is a necessary component of evaluating the reasonableness of the bids. PGE proposes three years of data, which is also reasonable. PGE also proposes that the bidder provide: "The historical and average energy output estimates . . . produced by a qualified independent third-party or consistent with an included energy assessment."[54] Developers should be allowed to use other industry standard modeling tools, which for solar generation includes PVSyst.[55] NIPPC understands that it is common in RFPs to use PVSyst runs as an estimate of solar generation output. NIPPC expects that independent third parties would likely be using satellite data anyway, but that the bidder would just be required to

[54] Id. § 6.1.8.
[55] E.g,, PVsyst Photvoltaic Software, available at http://www.pvsyst.com/en/.

pay an additional cost. If PGE or the IE have any concerns with the forecasted energy deliveries, then this can be reviewed in the bid evaluation process.

O. PGE's Remedial Action Schemes ("RAS") Provision Should Be Revised.

PGE includes two items regarding RAS that should be changed: 1) the PPA bidder should not be required to pay for RAS upgrades after the PPA is signed; and 2) PGE should be required to explain (and parties provide additional comment) how RAS are scored as a non-price factor.

As background, RAS are used to increase the transfer capability of the transmission system above what would be reliably allowed if RAS were not in place. At their most basic, RAS allow a generator to automatically trip in specific types of system emergencies. RAS are employed when generator tripping must happen so fast that there is not time for operators to react. The majority of the costs of RAS installations are in the substation and system controls and not at the project.

Installation of RAS (if desired by a transmission provider) is a cost of interconnection that is not assignable to a generator as it is considered a network upgrade at or beyond the point of interconnection. Therefore, if RAS are required, then the transmission provider and not the generator, should pay for the costs (or reimburse the transmission customer) as it does for other network upgrades.

PGE also included a non-price factor for RAS, assuming they are known at the time of bidding.[56] Specifically, PGE proposes that projects that PGE is able to use as a credit for its obligation to support AC intertie RAS will receive additional points. Projects subject to a RAS obligation on BPA's network will have points subtracted. This

[56] PGE 2018 Draft RFP § 8.8.2.

means that PGE penalizes a bidder if its project is required by PGE transmission to participate in RAS to ensure reliability of service to PGE loads. On the other hand, PGE gives points to a project that is required to participate in RAS to ensure the reliability of service to California loads over the intertie. NIPPC does not understand why RAS supporting the AC intertie receive a credit, while those supporting the Northwest grid will be penalized. PGE should be required to explain this difference, and the IE, Staff and parties an opportunity to comment on PGE's explanation.

P. PGE's Proposed Non-Price Evaluation Framework Is Not Reasonable

Historically, PGE placed considerable weight on what PGE loosely refers to as "Non-Price Scoring Factors" when evaluating bids, and this Draft 2018 Renewable RFP is no exception. Section 3.7 states that the "price score comprises 60 percent of the evaluation criteria" and therefore reflects "PGE's desire and commitment to obtain the best possible value for our customers." Thus, according to PGE, non-price factors comprise 40 percent. PGE states that its non-price factors "reflect commercial and performance risks in addition to the operational attributes of the bid proposals."[57]

As proposed by PGE, however, the Non-Price Scoring Factors can actually easily comprise more than 50 percent (and even more than 100 percent) of the evaluated cost difference between two project proposals that are almost identical in cost. Thus, the 60/40 split in this description is incorrect because of the way PGE applies the price scoring metric.

Non-price factors should be eliminated as much as possible because they can bias the results but understands that there will always be certain factors or characteristics of a

57 Id. § 3.7.

specific resource proposal that cannot be fully reflected in the bidders proposed pricing. To the extent that these factors or characteristics of a bidder's resource will influence or determine the ultimate cost of the resource to PGE ratepayers, NIPPC agrees that these factors or characteristics must be reflected in the final resource evaluation. It is a misnomer, however, to call these factors "Non-Price" as they generally do reflect aspects of the expected cost of the resource to ratepayers, but they reflect a cost or cost-savings to ratepayers that are not directly reflected or embedded in the bid price.

The key principles that should inform the selection of "non-price" scoring factors include:

- The weighting of any specific Non-Price scoring factors should reflect the magnitude of costs or benefits of that factor relative to the price evaluation score, so that the weighting of evaluation factors reflects PGE's best estimate of the actual costs or benefits to ratepayers of any non-price factor relative to the total costs and benefits of the resource,

- Non-Price Scoring Factors should not result in double-counting costs or savings that have already been captured in the Price Scoring Evaluation (i.e., no double-counting of costs or benefits already embedded in the bidder's bid price and contracting requirements). To do otherwise will distort the true cost and value of the proposed resource to the detriment of PGE ratepayers.

- The assignment of non-price "points" to any resource in the evaluation process should be explained and justified based on a clear nexus between the direction (i.e., cost or benefit) and magnitude of the non-price cost or benefit to ratepayers, and the assignment of non-price points added or subtracted from the price score assigned to each bid must be directionally correct (i.e., non-price evaluation factors that represent costs not embedded in the bid price should be subtracted from the price score and benefits that are not captured in the bid price score should result in points added to the bid price score.

- All non-price scoring factors should be applied uniformly and objectively to all ownership types in a non-discriminatory manner.

PGE's non-price evaluation framework, as proposed, fails to satisfy any of these principles. With these principles in mind, NIPPC offers the following summary assessment and recommendations for revising the Non-Price Evaluation scoring framework. NIPPC believes that if the RFP non-price scoring template is revised consistent with these principles, that actual weighting of price to non-price factors will be empirically based and supportable, and most likely result in a lower weighting of non-price factors relative to price (i.e., closer to an 80/20 split). A more complete evaluation of individual non-price factors and weightings proposed by PGE are included in Appendix A.

1. Non-Price Factors Are Too Subjective and Should Be Limited

Despite PGE's claim otherwise, this RFP allows an unprecedented amount of non-price points and should be revised to more appropriately balance price and non-price factors. Non-price factors are inherently subjective and allow PGE the opportunity to unfairly bias the evaluation. Non-price factors also handicap the IE from applying a largely quantitative analysis. NIPPC raised these issues directly with PGE and made these same arguments before the Commission during PGE's last RFP.[58] Rather than address the issues, like the over-reliance on non-price factors, PGE decided not to go forward with its 2016 RFP. Although PGE's current RFP provides more specificity then its last one, it still fails to provide sufficient protection from manipulation of non-price factors or adequately constrain the ability to sway the ultimate result based upon non-price points. By way of comparison, PacifiCorp's current RFP relies upon an 80/20 split.[59]

---

58 See Docket No. UM 1773, NIPPC Comments (June 6, 2016).

59 Re PacifiCorp 2018 RFP, Docket No. UM 1845, PacifiCorp Draft RFP at 21 (Aug. 4, 2017) ("Non-Price Evaluation (Up to 20%)").

A 60/40 (or even greater) split provides PGE the opportunity to effectively weigh non-price factors higher than the price factors to award a bid that is not the lowest cost and risk resource. The degree to which each non-price adjustment can affect (and/or distort) the overall score should be commensurate to the significance of each non-price factor. It is equally important, however, that the bid evaluation framework monetizes non-price factors commensurate with the relative overall price. Stated another way, non-price factors taken as a whole, must also be commensurate to the significance of the overall price and score. PGE's current RFP, like its previous one, does not align the relative magnitude of non-price scoring with the overall evaluation of the bid price, and ultimately favors non-price factors.

Worse yet, in 2016 PGE explained that the non-price adjustments occur *after* the pricing score, which means that although the price score may be relatively narrow between the least and highest cost resources, the addition of non-price points dilutes that critical difference and allows PGE to manipulate the results. This RFP will be scored sequentially. Awarding non-price points after the price-based scores are totaled is ripe for manipulation and signals impropriety. All points should be awarded before any totaling begins.

2. It Is Impossible to Accurately Estimate the Value of the Non-Price Factors Until the Price Evaluation Is Completed

PGE's non-price factors do not allow the IE, the Commission, stakeholders or potential bidders to understand how they will ultimately impact the RFP results until after the price scoring is completed. The purpose of weighting the Non-Price scoring factors should be to reflect the magnitude of each factor's costs or benefits relative to the price evaluation score. In other words, the weighting of evaluation factors reflects PGE's best estimate of the actual costs or benefits to ratepayers of any non-price factor relative to the total costs and benefits of the resource. In practice, this means that each discrete non-price "point" awarded to or charged to a bidder's price score should reflect the expected benefit or cost to ratepayers associated with that non-price factor over the life of the resource. If this principle is satisfied, then the implied value or costs of a single "point" awarded in the non-price evaluation should be valued the same as the actual value or cost represented by a single price point in the price evaluation. PGE's proposed non-price scoring system fails to satisfy this fundamental principle.

The value of each non-price point cannot be known in advance of when the price scoring bids are completed. Non-price factors cannot be specified in advance under the scoring system proposed by PGE because the value of any point awarded for actual bid price is a dynamic value that varies based upon the "Price Ratio" calculated by PGE for actual bids.[60] This can be explained with the following illustrations:

Example 1: Assume a simple evaluation of a two bid RFP and PGE's Proposal to Award 600 price points to the lowest cost resource bid into the RFP based upon price evaluation alone. Assume only a two bid RFP for two 300 MW wind resources with 35 percent capacity factors.[61] The implied value of each non-price point is $689,850 over the life of

60 The price ratio is the ratio of the levelized present value cost of a MWh as bid compared to the levelized present value of market power over the life of the resource.

61 Additional assumptions for this example include: 1) The levelized Present Value of Market Power Calculated by PGE is $45.00/MWh; 2) The price evaluation of Bid 1 yields a levelized present value cost of $22.50 MWh; 3) The price evaluation of Bid 2 yields a levelized present value cost of $30.00 MWh; and 4) Both Bid 1 and Bid 2 are 300 MW renewable energy projects with an expected annual capacity factor of 35 percent and are offered under a 20-year PPA. This means that each resource is expected to deliver 18,396,000 MWh of renewable energy to ratepayers over the life of a 20-year PPA (300 MW * 8760 hours/year * .35 capacity factor * 20 years).

the resource.[62] Stated differently, a resource that scores one point higher in the price evaluation than the next lowest cost resource would be calculated by PGE to save ratepayers $689,850 over the next lowest cost resource. Since the non-price factors are also used to assign points to individual bids, it follows that a single non-price point awarded implies a value to ratepayers of $689,850 over the life of the resource.

Example 2: If we make just one change in the above example to reflect a different bid stack, the evaluated value of a single price point will change.[63] In this scenario, the value of a price point in the evaluation would be $459,900, or 33 percent less than in the first example. What this demonstrates is that the value of a "point" in PGE's scoring system is unknown by PGE until the price evaluation is completed for all resources. What this also demonstrates is the value of a non-price point is unknown before the price evaluation is completed.

The manner in which PGE proposes to evaluate the non-price factors can bias the results as illustrated by the above examples. Under PGE's proposed non-price scoring template, any resource that is in operation will receive 70 bonus points.[64] Thus, PGE provides a higher value to an operating resource rather than a yet to be constructed facility. This is reasonable in principle, but it is impossible to determine if 70 or another number of points is reasonable because we do not know the value of any particular point.

In the second example above, assume that the lowest cost resource ($30 MWh) is not operational, but the higher cost bid ($32.50 MWh) is operational. Based upon the value of $459,900 per point in the second example above, this implies ratepayers should be willing to pay a significantly different amount for a resource that is already operating

---

62 Value of a single Price Point = (((levelized PV of market power in $ per MWh) - (levelized PV of lowest cost resource)) divided by 600 points) *Total MWh delivered over the life of the resource = (($45.00 - $22.50) ÷ 600) * 18,396,000 = $689,850.

63 For example, if we assume that Bid 1 above is $32.50 MWh instead of $22.50 MWh, it is no longer the lowest cost resource and Bid 2 becomes the lowest cost resource in the evaluation and is awarded 600 points.

64 PGE 2018 Draft RFP at Appendix H at 11 (5 raw points weighted by a factor of 14 equals 70 points).

compared to a lower priced resource that is not operational than if each point is worth $689,850.

The fundamental question is what is the added value to ratepayers of acquiring an operational resource compared to a resource that is contracted for and built for PGE? Under the evaluation framework proposed by PGE, PGE does not know until after the price evaluation is complete and neither will the IE, Staff, stakeholders or the Commission. In the first example, it is $689,850 per point. In the second example, it is $459,900 per point. While there may be some difference between the values of an operational versus a non-operational resource depending other factors, the wide and unexplained variations in PGE's approach are not reasonable.

NIPPC recommends that PGE revise the entire non-price section according to the principles outlined above. Specifically:

- Weighting of non-price factors should be based upon relative cost and/or benefit of the factor to ratepayers and not significant variation as a function of the price evaluation. This could be accomplished by converting the non-price factors into prices (i.e., $ MWh); however, other approaches could be reasonable.
- Apply every evaluation criteria to all resources (i.e., no carve out of special bonus points exclusively for one ownership type, for a benefit already embedded in the bids of other resources).

3. Many Non-Price Evaluation Criteria Proposed by PGE Serve to Double-count Ratepayer Costs and benefits already captured in the Price Evaluation

The Competitive Bidding Guidelines state that "[t]he non-price score should be based on resource characteristics identified in the utility's acknowledged IRP Action Plan (e.g., dispatch flexibility, resource term, portfolio diversity, etc.) and conformance to the standard form contracts attached to the RFP."[65] This requirement points to consideration of factors that are not already reflected in a bidder's bid price, yet PGE has included numerous non-price factors that double-count costs or benefits already embedded in bidder's price proposal.

There are two fundamental principles that should apply to any non-price score. First, the assignment of non-price "points" to any resource in the evaluation process should be explained and justified based on a clear nexus between the direction (i.e., cost or benefit) and magnitude of the non-price cost or benefit to ratepayers. Second, the assignment of non-price points added or subtracted from the price score assigned to each bid must be directionally correct (i.e., non-price evaluation factors that represent costs not embedded in the bid price should be subtracted from the price score and benefits that are not captured in the bid price score should result in points added to the bid price score).

PGE should remove all non-price bid factors from the evaluation that merely serve to double-count factors already captured in a developer's bid. NIPPC has included a factor-by-factor evaluation of PGE's non-price evaluation framework in Attachment B to these comments. Examples regarding certain key non-price factors are identified below.

a. Existing Resources

As explained above, PGE proposes that existing projects already in service receive 70 non-price bonus points. Most or all of this bonus proposed for an operating project represents double-counting of the benefits of an operating project that should already be reflected in the bid price of an existing resource. This is because all new

[65] Competitive Bidding Guidelines § 8.

resources bidding into the RFP will be held strictly to their bid prices, must meet strict credit requirements, must assume considerable exposure to penalties and liquidated damages, and costly performance guarantees. All of these should be reflected in the bid price. Existing projects can avoid many of these costs and should have already reflected those savings in their bid, if they want to be competitive. Therefore, PGE's proposal has an enormous advantage to existing resources, which should already be reflected in the existing resource's bid price.

b. Cost Certainty – Equipment

Non-price factor 2.e "Cost Certainty – equipment" proposes that project that include a "price guarantee for major equipment in addition to executable agreement for prime movers (e.g. turbines, panels)" receive 15 bonus points. This is backwards from the way this should be applied and as written would heavily bias the evaluation against PPA resources when compared to utility-ownership proposals. This is because PPA proposal are bid with guaranteed (firm) bid prices, so they have already met the cost certainty criteria in Factor 2.e. PGE's proposal would reward utility-owned bidders with bonus points for including price protection for ratepayers that are already embedded in every PPA bid.

The correct way to structure this non-price factor is for PGE to apply non-price penalty points to any bids that do not contain price guarantees, including the benchmark, to accurately represent the cost to ratepayers of assuming the risk of bidder cost overruns. This approach will achieve comparability in the evaluation process for this factor between PPAs and utility-ownership proposals. NIPPC identifies additional factors where PGE has made similar errors in constructing the non-price evaluation framework in Attachment B to these comments.

c. All Non-Bid Price Scoring Factors Should Be Applied Uniformly and Objectively to All Ownership Types in a Non-Discriminatory Manner

PGE's specification of non-price factors favors utility ownership. Specifically, PGE has included factors that apply only to utility-ownership bids and others that apply only to PPA bids. This is unjustified. If a project characteristic is deemed to impose costs or benefits on ratepayers that are not captured in the price evaluation, then all bids should be evaluated against that characteristic on a comparable basis, regardless of ownership type. PGE should not be allowed to design non-price evaluation factors that unfairly discriminate against a specific bid type. All bids should be evaluated fairly and objectively against each non-price evaluation factor, regardless of ownership type.

An example of this is non-price factor 2.h: "Cost Certainty-Pricing Structure" proposed by PGE. As proposed, this factor would only apply to PPA bids. Under this non-price factor, PGE proposes to award 10 bonus points to any PPA bid that does not include automatic price escalation and does not include a capacity payment. Presumably, the price evaluation of the PPA should have already captured the ratepayer benefit of no escalation so repeating that factor here is double-counting. Second, if PGE prefers contracts with no capacity payment, then it should establish a non-price penalty factor for any project that is bid with a capacity payment and scale the penalty to the magnitude of the required capacity payment relative to total payment on a bidder specific basis. By definition, utility-owned renewable resources are bid almost 100 percent capacity payment (i.e., PGE must finance the entire project up-front and pays a fixed capacity payment each year based-upon ratebase and allowed return on capital) and is subject to un-mitigated escalation in variable costs for the life of the utility ownership.

PGE also proposes to penalize a PPA bidders that structure their bids to include a partial capacity payment and/or escalation in certain variable costs such as transmission costs, but not penalize utility-ownership bids that are, by definition, almost pure capacity payments with un-mitigated ratepayer exposure to future escalation in variable costs.[66] This unfairly benefits utility-ownership bids in the evaluation process and harms ratepayers.

III. CONCLUSION

NIPPC therefore respectfully asks the Commission to direct PGE to revise its draft RFP in accordance with our recommendations detailed above.

Dated this 30th day of March 2018.

Respectfully submitted,

Irion Sanger
Sidney Villanueva
Sanger Law, PC
1117 SE 53rd Avenue
Portland, OR 97215
Telephone: (503) 756-7533
Fax: (503) 334-2235
irion@sanger-law.com

Attorneys for the Northwest and Intermountain Power Producers Coalition

[66] PGE 2018 Draft RFP at Appendix H at 12.

Attachment A

NIPPC's Full Critique of Specified Energy

I. CRITIQUE

A. Specified Energy

PGE's Specified Energy concept ensures that PPA projects will never earn the full PPA price for their generation and impedes upon the facility's ability to make up scheduling deviations. This means that PPA bidders cannot accurately project how much revenue they will obtain. This kind of uncertainty means that PPA bidders will need to increase their prices to account for the unknown and unnecessary risk PGE is imposing upon them. This necessarily limits the ability of PPA bidders to compete with PGE's Benchmark Resources, which does not face these onerous restrictions.

To understand how PGE uses Specified Energy to penalize PPA bidders, PGE relies upon a concept it refers to as "Specified Amounts" in its draft PPA. Section 1.1.118 defines "Specified Amounts" as,

> the amount of Firm Energy generated by the Facility that Seller is required to deliver to PGE at the Delivery Point for each monthly On-Peak period and for each monthly Off-Peak period during the Delivery Period. Amounts for each month during the following calendar year shall be established by Seller pursuant to Section 3.3.

Essentially this is the typical annual output forecast in megawatt hours ("MWh") from the PPA bid. As discussed below, however, PGE uses this forecast as both a guarantee and a cap. For the first three years, the Specified Amounts are equal to the 50 percent probability of generation. After three years, the Specified Amount is based upon a three-year rolling average of actual plant production. PGE then breaks the Specified Amount into 24 specified periods for each month of the year. Because renewable resources are variable in nature, some months will be more productive than others, but overall output tends to be fairly predictable. PGE's specified periods ensure that PPA bidders will not be able to have some "good" months and some "bad" months, but rather 24 bad periods every year.

PGE effectively penalizes PPAs by only paying the PPA price for the Specified Amounts during each specified period. This is the concept of "Specified Energy" in PGE's draft PPA. Section 1.1.119 defines "Specified Energy" as

> Firm Energy simultaneously bundled with the Facility's associated Environmental Attributes, including Bundled RECs, as generated and metered net of all Facility losses and station service at the Facility Meter, scheduled in hourly blocks, and delivered to the Delivery Point, up to the Specified Amount according [to] the Scheduling Procedure in Section 3.8.

The problem is that the "Scheduling Procedures in Section 3.8" indicate that PGE intends to match scheduled energy with generated energy each and every hour of the year. Any hour that generation is above or below its scheduled amount counts as "Unspecified Energy" under the PPA rather than Specified Energy under the 24 periods.[1] Unspecified Energy is paid the spot-market price instead of the PPA price. This allows PGE to strip IPPs of the ability to correct under-deliveries with over-deliveries to match the Specified Amounts.

Even when a PPA Seller schedules with 100% accuracy, it is subject to penalties if it is producing above-average amounts. PGE converts a portion of actual project output from Specified Energy to "As Available Energy" under the PPA when correctly-scheduled output exceed the Specified Amounts for the month.[2] When project output that is scheduled and

1 Section 1.1.119 of PGE's draft PPA defines Unspecified Energy as "portion of Firm Energy, measured in MWh, scheduled and delivered to Seller that was not generated by the Facility but is delivered to PGE as a result of Ancillary Services provided by a Balancing Authority area or Transmission Provider, or other entity, as applicable."

2 Section 1.1.5 defines "As Available Energy" as "any Firm energy, measured in MWh, scheduled and delivered from the Facility to the Delivery Point during a month that exceeds the Specified Amounts for such month."

delivered to PGE is converted by PGE to As-Available Energy, it loses the PPA price—even if the scheduled and delivered amounts match exactly.

Taken as a whole, these provisions mean that PGE only pays the PPA price for precisely scheduled power generated up to the Specified Amount. For power generated above the Specified Amount PGE discounts the power by paying the spot-market price, and if the facility produces less than the Specified Amount PGE discounts the power under its As-Available Energy provision. This is what strips IPPs of its ability to allow any “good” months (where a production is higher than average) to make up for “bad” months (where production is lower than average). It allows PGE to only pay the PPA price for the plant’s average production and pay a discounted rate for any above and below average production.

Attachment B

NIPPC’s Full Critique of Appendix H

I. CRITIQUE

A. PGE's Non-Price Scoring Factors

NIPPC has performed a line-item review of the specific Non-Price evaluation criteria proposed by PGE against the   For ease of understanding, NIPPC has reprinted Exhibit A -2018 Scorecard Template below and included comments on each Non-Price evaluation criteria in the Template. For consistency in comparison, NIPPC has used the implied ratepayer value of $0.0375 per MW and $1.03 million levelized PV per point as an example. NIPPC's calculation of the example and explanation are at the end of the summary of the price scoring factors below.

1. Product Already in Service (2)

Development Criteria	Score	Weight	Total	Scoring Rules
2. Project Development Criteria Max Score = 115			100	Measures likelihood that project to support proposal will be placed into commercial service on time and on budget
2. Project already in service	0	14	0	Use the following scoring rules for projects that are already in operation: Operating plants should be given a score of 5 points, however this score can be reduced by 1 point if the plant has experienced extended outages, shutdowns or closures during the asset life. For scoring product development from portfolios use the following rules: (1) If product mostly supplied from a specific plant, use that plant for scoring (2) If product supplied from several plants, use the average score from all plants.

PGE proposes that existing projects already in service receive 70 non-price points (5 points weighted by 14 for a total of 70). This implies that PGE ratepayers should be willing to pay $2. 45 per MWh (70*$0.0375) premium for a project that is already in service, or $72 million more in present value over the life of the project solely because it is already in operation ($1.03 million*70 points).

Most if not all of this bonus proposed for an operating project represents double-counting of the benefits of an operating project that should already be reflected in the bid price. All new resources bidding are being held strictly to their bid prices, strict credit requirements, exposure to significant penalties and liquidated damages, and costly performance guarantees, of the costs of which will be reflected in their (higher) bid prices. Existing projects can avoid many of these costs and development risks and should reflect those savings in their bid if they want to be competitive. NIPPC does not understand why PGE proposes an enormous downward price adjustment to bids from existing resources, for a price factor that should already be reflected in the existing resource's bid price.

2. Permitting Status (2.a)

<table>
<tr><td rowspan="3">2.a Permitting status (see permitting attachment)</td><td rowspan="3">2</td><td rowspan="3">10</td><td rowspan="3">20</td><td>2 = All project permits and Site Certificate approved.</td></tr>
<tr><td>1 = Major permits approved</td></tr>
<tr><td>0 = Permit process underway, all permits timely acquired consistent with identified thresholds</td></tr>
</table>

PGE proposes that projects that are fully permitted at the time of short-listing receive 20 bonus points. This implies that PGE ratepayers should be willing to pay $0.75 per MWh (20*$0.0375) premium for a project that is fully permitted, or $20 million more in present value over the life of the project, solely because project permitting is more advanced relative to other proposals at the time of short-list selection. This does not seem to be in ratepayer's best interest. When the project is completed, the timeline of actual permitting will have no effect on the cost or benefits of the project for PGE ratepayers.

NIPPC believes this proposed non-bid price factor represents double-counting of costs of protecting PGE ratepayers from development failures in the procurement process. PGE has incorporated significant measures into this RFP to mitigate the risks that any new project will fail or be delayed during the development process. Presumably, bidders have or will hedge this risk and will reflect the cost of this risk protection in their bid price as necessary. Projects that are further along in permitting and development face less risk and should incur lower costs to ensure they meet development milestones and project permitting. NIPPC expects that they should and will reflect these lower costs in their bid price. The proper way to protect ratepayers is to ensure bidders have proper incentives (e.g., performance guarantees, milestones with liquidated damage provisions, etc.) applied to their bids, a cost that will be reflected in their bid prices. NIPPC does not understand why PGE proposes a large downward price adjustment to any bidders bid price based solely upon a factor that will not affect the future cost of power to PGE ratepayers if they purchase the project in this RFP.

PGE should remove this non-price factor from the evaluation framework.

3. Experience of Project Team (2.b)

<table>
<tr><td rowspan="3">2.b Experience of Project Team</td><td rowspan="3">2</td><td rowspan="3">5</td><td rowspan="3">10</td><td>2 = Successfully developed multiple similar projects in WECC delivered on time without material facility unplanned outages within first year.</td></tr>
<tr><td>1 = Successfully developed multiple similar projects in US.</td></tr>
<tr><td>0 = Successfully developed similar project in US.</td></tr>
</table>

PGE proposes that projects proposed by those developers that have an historic development profile that looks exactly like PGE should receive 10 non-price bonus points. This implies that PGE ratepayers should be willing to pay $10 million more in present value for PGE's benchmark resource compared to lower cost resources from highly successful bidders with proven track records in other parts of the country (i.e., non-WECC).

This proposed non-bid price factor represents another double-counting of the costs of protecting PGE ratepayers from development failures in the procurement process. PGE has incorporated significant measures into this RFP to mitigate the risks that any new project will fail or be delayed during the development process. Presumably, bidders have or will hedge this risk and will reflect the cost of this risk protection in their bid price as necessary. Projects that are proposed by experienced developers should benefit from their development experience and track record when it comes to the cost of credit support, financing and avoidance of schedule delays and associated liquidated damages. NIPPC expects that they should and will have reflected these lower costs in the form of a lower bid price. The proper way to protect ratepayers is to ensure bidders have proper incentives (e.g., performance guarantees, milestones with liquidated damage provisions, etc.) applied to their bids, a cost that will be reflected in their bid prices. NIPPC does not understand why PGE proposes a large downward non-bid price adjustment to any bidder's bid price, based solely upon a factor that will not affect the future cost of power to PGE ratepayers if they purchase the project in this RFP.

PGE should remove this non-price factor from the evaluation framework.

4. Project Financing (2.c)

2.c Project Financing	1	10	10	1 = Project can be internally financed by developer. Alternatively, project has financing agreement (e.g. primary lender, and tax equity as appropriate) with credible funding source with joint commitment to proceed. 0 = PGE bid award needed to obtain financing (e.g. lender commitment contingent on bid award)

PGE proposes that projects proposed by those developers that are capable of internally financing a resource development (i.e., balance sheet financing) be awarded 10 non-price points. This implies that PGE ratepayers should be willing to pay $10 million more in present value for a resource solely because the developer is theoretically capable of internally financing the project.

NIPPC does not understand why PGE proposes a large downward price adjustment to any bidders bid price based solely upon a factor, the ability to internally finance the project, that will not affect the future cost of power to PGE ratepayers if they purchase the project in this RFP. (NIPPC notes that PGE's last project, the ill-fated Carty Generating Project, was developed by two large companies, Abengoa and PGE, that both relied on internal financing). Most projects developed under PPAs, even those built by companies that are well capable of internally financing their project, are ultimately project financed using non-recourse financing because it typically will lower overall project financing costs compared to balance sheet (internal) financing.

It appears that this non-price factor may bias the RFP evaluation to favor utility owned or benchmark projects in this RFP because this is exactly what this bonus is. Any utility owned bids selected in this RFP, whether build-transfer or benchmark, will be internally financed by PGE while PPA bids will most likely rely on lower cost project financing. PGE's cost-of-capital is higher than that of creditworthy IPP's, a reality not lost on PGE. There is no basis for PGE to include this non-price evaluation in factor in this RFP, which discriminates against PPA bidders that have access to lower-cost IPP project financing in favor of PGE benchmark and utility owned proposals that rely on higher-cost balance sheet financing. This non-bid price factor must be removed from the non-price evaluation.

5. Site Control (2.d)

2.d Site Control: Including all rights required for project including access to the project site, easements and resources rights appropriate for the project	1	15	15	1 = Title/Executed lease or options for a minimum of 100% of site 0 = Title/Executed lease or options for a minimum of 80% of site

PGE proposes that projects proposed by those developers that have executed a lease and/or options for 100 percent of a project site be awarded 10 non-price points. This implies that PGE ratepayers should be willing to pay $15 million more in present value for a resource that controls 100 percent of a site when their bid is submitted. However, 100 percent site control is a threshold requirement for any bidder to be selected for the short-list.

Because any bidder must demonstrate 100 percent site control to be placed on the short-list, this provision is redundant and cannot be connected or attributed to any benefit for PGE ratepayers. NIPPC does not understand why PGE would want to give bonus price points for projects solely for meeting a threshold requirement to qualify for short-listing.

This redundant non-bid price factor should be removed from the non-price evaluation framework.

6. Cost Certainty - Equipment (2.e)

2.e Cost Certainty - equipment All proposals regardless of current online status	3	5	15	2 = Pricing guarantee for identified major equipment in addition to executable agreement for prime movers (e.g. turbines, panels)
				1 = Executable agreement for prime mover (e.g. turbines, panels)
				0 = OEM quotes for prime mover (e.g. turbines, panels)
				+1 for LTSA or other long-term service quote

PGE proposes to provide up to 15 non-price points to utility ownership bids for meeting what should be a threshold requirement for a utility owned resource bid; a price guarantee. PPA bids by definition have embedded price guarantees for major equipment by virtue of their fixed price bids. This proposed non-price factor implies that PGE ratepayers should be willing to pay $15 million more in present value for a utility ownership proposal that provides enhanced price protection of the kind already provided by PPA's. This does not make sense.

NIPPC believes this factor could be structured as a valid non-price factor applied equitably to all bid types, but PGE has got it backwards. PPAs should not be affected by this factor as they already come in the form of a guaranteed price and implicit guarantee of equipment costs. Utility ownership bids on the other hand, should be required to be bid with equivalent PGE price protection of a PPA. If not a threshold bidding requirement, then PGE should subtract points from risky utility ownership bids that do not come with these ratepayer protections.

In this case, any utility ownership bids (including benchmark) that do not offer an executable agreement for prime mover should be assigned negative points. Likewise, if they do not have a price guarantee for major equipment, they should be assigned more negative points. Finally, it they don't submit a Long Term Services Agreement or quote, they should be assigned even more negative points.

7. Value of Extension (2.f)

2.f Cost Certainty – Value of Extension	2	10	20	2 = Allows contract extension at original contract price or purchase option at book value or allows for continued operation at cost for benefit of customers
				1 = Allows contract extension at price certain or purchase option at known price
				0 = Allows for no rights for contract extension or purchase option. Alternatively allows for contract extension or purchase option at unknown price (e.g. fair market value)

NIPPC believes this could be an appropriate non-price factor, but challenges the weighting assigned by PGE. PGE proposes to provide up to 20 non-price points automatically to all utility ownership bids whereas PPA bidders must offer a purchase option at end of PPA to get the same bonus points that will automatically accrue to utility ownership bids. This proposed non-price factor implies that PGE ratepayers should be willing to pay $20 million more in present value for any bid that provides an option for ultimate PGE ownership. This is a large amount of money to pay up front for a highly uncertain possible benefit.

PGE should be required to explain how they arrived at this value, and to justify their decision to award 20 non-price points for this optionality, for which the value of any ratepayer benefits are speculative.

8. Milestone Payments (2.g)

2.g Cost Certainty - Milestone payments	1	10	10	1 = Payments at, or under PGE suggested milestone schedule (i.e. payments total less than actual completion percentage prior to completion)
				0 = Payments match with PGE suggested milestones
				-1 = Payments front loaded relative to proposed schedule of values and milestone payment schedule

This is a proposed non-price factor that proses up to 10 bonus points but is only available to utility ownership bids. Further, the factor is mis-identified as bringing some cost certainty to a utility owned project. The criteria for award of points does not address cost certainty. Rather, the criteria speaks to how much and how fast PGE must provide working capital to a project developer in the form of progress payments.

Specifically, PGE proposes that utility ownership proposals where the developer provides more working capital during project construction than the minimum required by PGE would get 10 bonus points. By definition, PPA proposals do not require any contribution to working capital by PGE so this non-price factor discriminates against PPA proposals. NIPPC believes that in general, any non-price factors should be applied to all bids on a non-discriminatory basis.

NIPPC believes that utility ownership bids that provide ratepayer benefits and risk protection by skewing PGE progress payments to later in the construction cycle should receive bonus value in the evaluation process. However, because PPAs already provide these ratepayer benefits and risk protection, failing to also give these points to PPAs would be unduly discriminatory and harm PGE ratepayers. PPAs should automatically receive the full non-price points for Cost Certainty as they require no milestone payments at all.

9. Pricing Structure (2.h)

2.h Cost Certainty – Pricing Structure	0	5	0	2 = Contract price does not escalate and does not include capacity payment
				1 = Contract price escalating at known and committed escalation rate and does not include capacity payment
				0 = Contract price escalating at market based escalator (e.g. historical CPI) or does include capacity payment

This is a proposed non-price factor that proposes up to 10 bonus points but is only available to PPA bids. Specifically, PGE proposes that PPA proposals that do not escalate and do not include capacity payments receive 10 bonus points. In general, any non-price factors should be applied to all bids on a non-discriminatory basis and objects to any non-price factor that targets a subsection of resources.

PGE apparently believes that projects that come with capacity payments are less desirable than pure output type contracts and are proposing here that PPAs that bid level payments over the life of the PPA (no escalation) and are bid as pure output contracts (i.e., no capacity payment component) should be valued more than utility ownership proposals that are almost pure capacity payment structures and come with variable cost escalation at unknown rates over the life of the utility ownership. However, PGE has approached this issue backwards.

NIPPC proposes the following changes to this non-price evaluation factor. First, this proposal inappropriately concatenates two disparate cost factors: 1) escalation rates; and 2) capacity payments versus output payments. They should be addressed separately.

For escalation rates, PGE should indicate a preference for bids with no escalation and those bids that comply get no non-price points. PPA bids that are offered with no escalation should receive zero points because that is what is requested by PGE. Utility ownership bids, by definition, come with lifetime exposure to escalation and inflation, and should be appropriately penalized under this non-price factor.

For capacity payments, once again, PPAs that bid pure output contracts (i.e., no capacity payments) should receive zero points because that is PGE's preference as expressed in the RFP. Utility ownership bids, by definition, are almost entirely capacity payment based (i.e., they are rate based with fixed annual depreciation expenses and a fixed return on capital) and should be appropriately penalized under this non-price factor.

10. Interconnection Rights (3.a)

<table>
<tr><th>Physical Characteristics</th><th>Score</th><th>Weight</th><th>Total</th><th>Scoring Rules</th></tr>
<tr><td>3. Physical Characteristics Max Score = 150</td><td></td><td></td><td>130</td><td>Measures project specific physical attributes for each offer.

For scoring physical characteristics from portfolios use the following rules: (1) If product primarily supplied from a specific plant, use that plant for scoring; (2) If product supplied from several plants, use the average score from all plants.</td></tr>
<tr><td rowspan="6">3.a Interconnection Rights</td><td rowspan="6">5</td><td rowspan="6">10</td><td rowspan="6">50</td><td>5 = Executed LGIA or project in operation.</td></tr>
<tr><td>4= Tendered LGIA, in Negotiations.</td></tr>
<tr><td>3 = Executed optional Engineering and Procurement Agreement (E and P) or procurement agreement for long-lead interconnection items if applicable.</td></tr>
<tr><td>2 = Completed Interconnection Facility Study (must be completed prior to final short list).</td></tr>
<tr><td>1 = Completed Interconnection System Impact Study.</td></tr>
<tr><td>0=Executed System Impact Study Agreement.</td></tr>
</table>

This proposed non-price factor would provide 50 bonus points to any existing operating project as well as up to 50 bonus points to new projects depending on where the project is in the interconnection process. NIPPC will address these two factors separately.

For existing projects, PGE is proposing to award 50 points for simply being already built. This implies that PGE ratepayers should be willing to pay $1.87 per MWh (50*$0.0375) premium for a project that is already in service, or $50 million more in present value over the life of the project solely because it is already in operation ($1.03 million*70 points). This bonus is on top of the 70 point bonus automatically awarded to existing projects under Development Criteria 2.0 above. This means that PGE proposes to award 120 bonus points to any existing project bid to PGE solely by virtue being in operation, valued at $125 million under this example. NIPPC does not understand why PGE thinks ratepayers should be willing to pay $120 million more for a project that is already built, compared to a project built for PGE.

PGE is also proposing to award 50 bonus points automatically to any resource that has executed an LGIA which implies that ratepayers should be willing to pay up to $50 million more for a resource based upon what stage the resource is in the interconnection process. This does not make sense. Once a project is in operation, the timing of the interconnection study process will not have any effect on the cost or value of power from any project acquired. PGE has also got this backwards as well. If PGE perceives that any project places development risks on PGE ratepayers that have not been sufficiently mitigated by bid security, milestones and liquidated damages, etc., then PGE should subtract points from the risky bid(s).

11. BPA Transmission Rights (3.b.1)

3.b.1 Long Term Firm Transmission Rights on BPA's transmission		4	10	40	4 = Existing long-term firm rights to BPAT.PGE POD. 3 = Existing long-term firm rights confirmed by transmission provider to be redirectable to PGE's system. 2 = Executed PTSA for existing firm transmission to BPAT.PGE POD. 1 = PTSA agreement executed for identified upgrades. PTSA contains offer of conditional firm-bridge service that converts to long-term service upon completion of upgrades. Facility upgrades to be completed no later than one year after COD. 0 = Have completed TSEP and require near-term viable upgrades which must be completed at least six months prior to COD. PTSA agreement not yet executed.

This proposal by PGE is duplicitous. PGE has sufficient un-committed transmission on the BPA system and has 500 MW of additional surplus Boardman transmission on the BPA system beginning in 2020 when Boardman is retired. PGE should make their surplus Boardman transmission available to bidders and remove this non-price factor from the evaluation.

It is bad enough that PGE proposes to hoard transmission for the benefit of PGE's benchmark resource. It adds insult to injury for PGE to then claim that PGE ratepayers should be willing to pay $40 million more for PGE Benchmark Resource (i.e., receive 40 bonus points in the evaluation) simply because PGE can bring their surplus transmission to their benchmark project.

12. PGE Transmission Rights (3.b.2)

3.b.2 Long Term Firm Transmission Rights on PGE's Transmission	0	10	0	4 = Executed Interconnection Agreement with Network Resource Integration Service or existing long-term firm rights.
				2 = Tendered Interconnection Agreement with Network Resource Integration Service or executed Construction Agreement.
				1 = Completed Facility Study.
				0 = Completed System Impact Study.

This proposed non-price factor would provide up to 40 bonus points to new projects interconnecting to PGE, depending on where the project is in the interconnection process. This implies that ratepayers should be willing to pay up to $40 million more for a resource based upon what stage the resource is in the interconnection process. Once a project is in operation, the timing of the interconnection study process will not have any effect on the cost or value of power from any project acquired. PGE has also got this backwards as well. If PGE perceives that any project places development risks on PGE ratepayers that have not been sufficiently mitigated by bid security, milestones and liquidated damages, etc., then PGE should subtract points from the risky bid(s).

13. BPA Oversupply Management (3.c)

3.c Projects Subject to BPA Oversupply Management Protocol	0	-10	0	1 = Project subject to BPA Oversupply Management Protocol.
				0 = Project not subject to BPA Oversupply Management Protocol.

PGE proposes to apply 10 penalty points to any resource subject to BPA Oversupply Management. As NIPPC has shown in its comments, forcing bidders to embed the cost of BPA balancing services in their bids is discriminatory against PPA bidders and contrary to the best interests of PGE ratepayers. PGE should retain the flexibility over time to arrange and pay for balancing all resources that PGE acquires through this RFP, in a way that provides the greatest value to ratepayers. PGE does not force its own resources to subject themselves to BPA Oversupply Management, they should no force PPA bidders to do so.

This non-price factor must be removed from the evaluation.

14. Remedial Action Schemes (3.d)

3.d Remedial Action Scheme Projects Subject to (RAS)	1	10	10	**1 = PGE able to use resource as a credit for its obligation to support AC intertie RAS.**
				0 = No RAS.
				-1 = Subject to RAS other than the AC intertie.

Remedial Action Schemes ("RAS") are a reliability measures implemented by Transmission Providers for the purpose of increasing the firm transfer capability of the transmission system. RAS does not impose any material costs on a resource and resources are required to participate in RAS if asked. If RAS is needed, any implementation costs are assumed by the Transmission Provider and rolled into transmission rates charges to everyone. NIPPC does not understand why PGE proposes to penalize renewable projects that contribute to reinforcing the transmission grid serving PGE loads, especially given that RAS does not impose any material costs to the project. Adding to NIPPC's confusion is proposal above to actually award 10 bonus points to renewable projects that reinforce the transmission grid serving California loads.

It appears to NIPPC that this non-price factor is nothing short of a bonus that will likely apply to only one resource in this RFP: PGE's Benchmark Resource. This is because PGE proposes a benchmark resource delivered over PGE's Boardman transmission line to BPA's Slatt substation on the AC Intertie to California.

This non-price factor must be removed from the evaluation.

15. Engineering Reliability (3.e)

3.e Engineering Reliability	5	2	10	For all project types (maximum of 5 points)
				1 = PGE is able to influence in maintenance and availability decisions impacting reliability (0 if no influence).
				2 = The experience and expertise of O&M operator (<5 years=0, 5-9 years=1, >10 years=2).
				1 = The owner and/or operator is supported by local or centralized engineering staff (0 otherwise).
				1 = The seller has an established relationship with prime mover vendor including vendor support through a service agreement (<5 years=0, 5-9 years=.5, >10 years=1).

This non-price factor bears no relation to the objective of securing the lowest cost, least risk project for PGE ratepayers. Rather, is appears to be another bonus that is written to apply to PGE's Benchmark Resource.

This non-price factor must be removed from the evaluation.

16. Resource Certainty (3.f)

Resource Specific Issues				
3.f Resource Certainty	**Wind/Solar/Hydro Resources**			
	4	5	20	4 = 7+ years data.
				3 = 6-years data.
				2 = 5-years data.
				1 = 4-years data.
				0 = 3-years data (threshold).
				2 = Wind project is a staged build-out of an adjacent project (assumes adjacent project has at least 7 years' wind data and the adjacent project has a similar wind microclimate to the original project).
	Geothermal Resource			
	0	20	0	1 = Production and injections wells for the project drilled and completed.
				0 = Feasibility report completed, based on >1 year of test data from full diameter production wells.
	Biomass/Biogas – Project Fuel Supply			
	0	5	0	4 = Firm access to multiple fuel sources for 100% or greater of need, with ability to store fuel on site and options for fuel transportation.
				3 = Firm access to multiple fuel sources for 100% or greater of need.

				2 = Have executed long-term fuel supply contract for minimum of 60% of need with ability to store fuel on site and options for fuel transportation.
				1 = Have executed long-term fuel supply contract for minimum of 60% of need with plan for remaining need.
				0 = Have fuel supply plan with identified, established suppliers and transportation options.

This non-price factor proposes 40 bonus points for a wind project that has 7 years of wind data compared to 3 years of wind data (threshold). This implies PGE ratepayers should be willing to pay $40 million more for a wind project that has more historical wind data. This despite the fact that wind data does not affect the bid price of a project.

This appears to be yet another non-price factor that is designed give bonus points to a utility owned resource that will by definition come with extensive risk of performance to PGE ratepayers compared to PPA bids that are pay-for-performance and do not put the same level of risks on ratepayers. If PGE wants to reflect the risk of resource underperformance in the non-price factors, then it should give zero points for PPAs and penalty points to utility owned and benchmark resources that do not have seven years of meteorological data.

17. Firmness of Energy (4.a)

4. Performance Certainty Max Score = 100			120	Measures project specific commercial and delivery attributes for each offer.
4.a Quality of Power - Firmness of Energy	2	10	20	2 = Backed by physical resources or system with resupply obligation for curtailments or outages including make whole provisions for bundled RECs.
				1 = Backed by physical resources or system with finite resupply obligation for curtailments or outages including finite make whole provisions for bundled RECs.
				0 = Finite resupply obligation without make whole provisions for RECs.

This non-price factor proposes to give 20 bonus points to a renewable resource that is backed by a physical system with resupply obligation for curtailments or outages. This non-price factor does not make sense. All resources acquired through this RFP will be PGE ratepayer resources that are delivered on firm transmission and are backed by the PGE system. This non-price factor should be removed from the evaluation framework.

18. Scheduling Period Commitment (4.b)

4.b Quality of Power - Scheduling Period Commitment	2	5	10	2 = Weekly or greater in scheduling.
				1 = Pre-schedule.
				0 = Hourly.

NIPPC believes that PGE ratepayers are best off when PGE retains control of the scheduling of all ratepayer resources. This non-price factor should be removed from the evaluation framework.

19. Online Date (4.c)

<table>
<tr><td rowspan="3">4.c Online Date</td><td rowspan="3">2</td><td rowspan="3">10</td><td rowspan="3">20</td><td>0 = prior to 12/31/2019.</td></tr>
<tr><td>2 = After 12/31/2019 and prior to 12/31/2020.</td></tr>
<tr><td>1 = After 12/31/2020.</td></tr>
</table>

This non-price factor proposes to reward a project with 20 points that comes on-line a year before Boardman is retired but only 10 points for a project that comes on-line a year later when Boardman is retired. PGE should justify why they believe PGE should be willing to pay $10 million more for a resource that comes on-line a year before Boardman is retired.

20. Output Guarantee (4.d)

<table>
<tr><td rowspan="6">4.d Output Guarantee</td><td rowspan="6">10</td><td rowspan="6">3</td><td rowspan="6">30</td><td>Project owner financially guarantees project output for PGE customers through AUT forecast or PPA Form Contract Specified Amount provisions, defined over the following time period:</td></tr>
<tr><td>10 = Monthly On/Off Peak or more granular.</td></tr>
<tr><td>8 = Monthly.</td></tr>
<tr><td>6 = Quarterly.</td></tr>
<tr><td>2 = Annually.</td></tr>
<tr><td>0 = Multiple Consecutive Years.</td></tr>
</table>

This non-price factor proposes up to 30 bonus points for projects with output guarantees. NIPPC believes that this should be factored into the project "benefits" calculation as part of the price evaluation. If PGE sees value in specific performance or output guarantees, they should calculate that value and add it to the project benefits calculation when performing the price calculation. This non-price factor should be removed and incorporated into the price evaluation framework.

21. Various Contract Terms

The below non-price factor proposes to award up to 6 points each for conformance with terms of the model contracts related to liability caps. NIPPC has two issues with the way PGE has proposed this non-price factor. First, the criteria for different point scores are unnecessarily vague, i.e., “most”, “some”, “low”, “medium” etc. PGE should be more specific so bidders have a better idea of the cost of deviating from the terms of the model contract.

NIPPC would also point out, yet again, that PGE has constructed this non-price factor backwards. Bidders that conform their bids to the model contract should receive zero non-price points. Bids that depart from the model contract should be exposed to penalty (negative) point, and such penalty points must bear some empirical relationship to the cost that such contract deviations will impose on PGE ratepayers.

a. Liability Cap (4.f)

4.f Liability Cap Contractual Terms and Conditions Redlines	6	1	6	6 = All highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				3 = Most highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				1 = Most highlighted terms conform to contract form and present low risks to schedule, performance or cost.

				0 = Most highlighted terms conform to contract form and present medium risks to schedule, performance or cost.

b. Indemnification Conditions (4.g)

4.g Indemnification Contractual Terms and Conditions	6	1	6	6 = All highlighted terms conform to contract form and
				present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				3 = Most highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				1 = Most highlighted terms conform to contract form and present low risks to schedule, performance or cost.
				0 = Most highlighted terms conform to contract form and present medium risks to schedule, performance or cost.

c. Default & Termination Terms (4.h)

4.h Default & Termination Contractual Terms and Conditions	6	1	6	6 = All highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.

				3 = Most highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.
				1 = Most highlighted terms conform to contract form and present low risks to schedule, performance or cost.
				0 = Most highlighted terms conform to contract form and present medium risks to schedule, performance or cost.

d. Security & Collateral Terms (4.i)

4.i Security and Collateral Contractual Terms and Conditions	6	1	6	6 = All highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.

e. Guarantees and Remedies (4.j)

4.j Performance Guarantees and Remedies of Non-Performance Contractual Terms and Conditions	6	1	6	6 = All highlighted terms conform to contract form and present low risk to schedule, performance or cost, and additional terms are included that lowers Company risk.

B. PGE's Overall Approach

Historically, PGE has chosen to place considerable weight on what PGE refers to as "Non-Price Scoring Factors" when evaluating bids, and RFP is no exception. As proposed by

PGE, the Non-Price Scoring Factors can easily comprise more than 50 percent of the evaluated cost difference between two project proposals that are almost identical in cost. PGE describes its evaluation framework as weighted 60 percent Price and 40 percent Non-Price factors, but this description is incorrect and misleading because of the way PGE applies the price scoring metric, which can result in the non-price score being weighted more than 50 percent (and even more than 100 percent) of the evaluated price difference between resources.

NIPPC understands there will always be certain factors or characteristics of a specific resource proposal that cannot fully be reflected in a bidder's proposed pricing. To the extent that these factors or characteristics of a potential resource will influence or determine the ultimate cost of the resource to PGE ratepayers, NIPPC agrees these factors or characteristics must be reflected in the final resource evaluation. It is a misnomer, however, to call these factors Non-Price as they generally do reflect aspects of the expected cost of the resource to ratepayers; these factors reflect a cost or cost-savings to ratepayers that are not directly reflected in the bidders bid price.

NIPPC believes that there are key principles that should inform the selection of "non-bid price" scoring factors. They are:

- The weight of any specific Non-Price scoring factors should reflect the magnitude of costs or benefits of that factor relative to the price evaluation score, so that the weight of evaluation factors reflects PGE's best estimate of the actual costs or benefits to ratepayers of any non-price factor relative to the total costs and benefits of the resource;
- Non-Price Scoring Factors should not result in double-counting costs or savings that have already been captured in the Price Scoring Evaluation (i.e., no double-

counting of costs or benefits already embedded in the bidder's bid price and contracting requirements). To do otherwise will distort the true cost and value of the proposed resource to the detriment of PGE ratepayers.

- The assignment of non-price points in the evaluation process should be explained and justified based on a clear nexus between the direction (i.e., cost or benefit) and magnitude of the non-price cost or benefit to ratepayers, and the assignment of non-price points added or subtracted from the price score assigned to each bid must be directionally correct (i.e., non-price evaluation factors that represent costs not embedded in the bid price should be subtracted from the price score and benefits that are not captured in the bid price score should result in points added to the bid price score;
- All non-price scoring factors should be applied uniformly and objectively to all ownership types in a non-discriminatory manner.

With these principles in mind, NIPPC offers the following recommendations PGE's non-bid price factors. The appropriate point weighting of Non-Bid Price Factors cannot be specified in advance under the scoring system as proposed by PGE because the value of any point awarded for actual bid price is a dynamic value that varies based upon the "Price Ratio" of actual bids. PGE ignores this fundamental analytical truth and has proposed the non-bid price scoring system that will always yield arbitrary results at best and are almost certain to yield absurd results in practice. This can be easily explained and demonstrated using PGE's Illustrative Scoring Example below from Table 1 in RFP Appendix H.[1]

[1] PGE 2018 Draft Renewable RFP at Appendix H at 3

PGE's example depicts a total of nine qualifying bids that have been scored and ranked based upon the Evaluated Cost-to-Benefit Ratio. For purposes of this example, we will assume that all nine qualifying bids are for 300 MW wind projects with an expected annual capacity factor of 35 percent, and will deliver 27,594,000 megawatt hours ("MWh") to PGE ratepayers over the 30 year period PGE has chosen to levelized project costs and benefits (0.35 CF * 300 MW *8760 * 30 years). PGE does not compare raw bid prices between bids but rather calculates a unique cost-to-benefit ratio for each bid. The cost-to-benefit ratio is the ratio of the real levelized offer cost divided by the equivalent real-levelized benefits value (incorporating energy, capacity and flexibility benefits). This is the core of the problem with the non-price scoring framework, as this critique will demonstrate.

For example, assuming that the real levelized benefits (i.e., levelized PV market value) of the lowest cost resource bid (i.e., the bid with the lowest cost-to-benefit ratio) in PGE's example is $45 MWh, then because the lowest cost bid in PGE's example has a cost-to-benefit ratio of 38 percent, the real levelized offer cost of this resource would be 38 percent of $45 MWh market value, or $17.10 MWh. With a bid price of $17.10 MWh compared to the market valuation of the power at $45 MWh, this resource is expected to deliver power to PGE ratepayers with a net value of $27.90 MWh ($45 MWh benefit value minus $17.10 bid price). Because this is the lowest cost bid, PGE will award this bid the maximum available 600 price points. From these two numbers, one can easily determine the implied value of each price point awarded, which is a levelized value to ratepayers of $0.0465 per MWh, or approximately $1.28 million levelized present value per point.

Under PGE's proposed non-bid price scoring system which awards both positive and negative points, awarding positive non-bid price points has the effect of lowering the evaluated cost-to-benefit ratio making the project look even lower cost than determined by the price evaluation alone. Assigning negative non-bid price points on the other hand has the effect of increasing the cost-to-benefit ratio of any individual project's bid.

PGE's bid scoring proposal awards up to 400 bonus points per proposal for non-bid price factors and under the example above, with the value of a point worth $0.0464 per MWh, a project receiving all 400 non-price bonus points would be evaluated as bringing with it non-price ratepayer benefits equal to $18.60 MWh (0.0464 * 400), or 109 percent of the bid price ($18.60 MWh non-price benefits ÷ $17.10 bid price). These results are arbitrary: note that here the maximum available non-bid price points represented 67% of the lowest cost project's bid price.

PGE may attempt to dismiss the above example, because it was not chosen to represent a real bidding stack, and claim that it deliberately exaggerated the differences between the bid prices in the example to make it easier to understand the evaluation process. To test this, NIPPC has modified PGE's example to reflect a tighter grouping of bid prices and project cost-to-benefit ratios closer to 1.0. Specifically, NIPPC removed the two lowest cost bids leaving seven bids, and the lowest cost remaining project now has a cost-to-benefit ratio of 50 percent (compared to 38 percent in the original table.

For purposes of this second example, let's again assume that the real levelized benefits value of the lowest cost resource bid (i.e., the bid with the lowest cost-to-benefit ratio) in PGE's example is $45 MWh. Because the lowest cost bid in this example has a cost-to-benefit ratio of 50 percent, this means that the levelized offer cost of this resource is 50 percent of the $45 MWh market value, or $22.50 MWh. With this bid price of $22.50 MWh compared to the valuation of the power at $45 MWh, this resource is expected by PGE to deliver power to PGE ratepayers with a net value of $22.50 MWh ($45 MWh value minus $22.50 bid price). Because this is the lowest cost bid, PGE will award this bid the maximum 600 available price points. From these two numbers, one can easily determine the implied value of each price point awarded, which in this case is a levelized value of $0.0375 per MWh, (compared to $0.0465 per MWh in the first example), or approximately $1.03 million levelized present value per point (compared to $1.28 million in the first example).

Once again, PGE's bid scoring proposal awards up to 400 bonus points per bid for non-price factors and under this second example above, with the value of a point being $0.0375 per MWh, a project receiving the full 400 non-bid price bonus points would be evaluated as bringing with it non-price ratepayer benefits equal to $15.00 MWh (0.0375 * 400), or 67 percent of the lowest cost project's bid price ($15.00 MWh non-price benefits ÷ $22.50 bid price). This compares to the first example where the maximum available non-bid price points represented 109% of the lowest cost project's bid price. Once again, these result falls into the category of arbitrary and absurd.

On its face, an evaluation framework like PGE has designed, which leaves the relative value (weighting) of non-bid price factors to float in the evaluation process in an arbitrary fashion depending on the distribution of bid prices received, PGE guarantees that the results of its proposed bid evaluation framework will produce arbitrary and misleading results to the detriment of PGE ratepayers. This system is also unfair to prospective bidders. Add to this the reality that PGE's proposal can result in a weighting of non-price factors as great or greater than the bidder's bid price is evidence of a deeply flawed evaluation framework. As currently proposed, PGE's RFP evaluation is unlikely to select the best resources offered in this RFP and bidders will be unable to understand or even estimate how their bid will be evaluated.