BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 73

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2019 Integrated Resource Plan	NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION'S OPENING COMMENTS (REDACTED)

I. INTRODUCTION

The Northwest and Intermountain Power Producers Coalition ("NIPPC")[1] respectfully submits these Comments for consideration by the Oregon Public Utility Commission ("Commission") on Portland General Electric Company's ("PGE") 2019 Integrated Resource Plan ("IRP"), the Addendum to PGE's 2019 IRP Interim Transmission Solution, and PGE's Errata to the 2019 IRP. NIPPC's comments address the following issues: 1) transmission planning; 2) direct access planning; and 3) compliance with the Commission's administrative rules that require certain elements of PGE's request for proposal ("RFP") be adequately described in PGE's IRP.

A. Transmission Recommendations:

NIPPC recommends that the Commission decline to acknowledge PGE's IRP transmission plan because PGE completely failed to consider transmission cost,

[1] NIPPC is a membership-based advocacy group representing electricity market participants in the Pacific Northwest. NIPPC members include independent power producers ("IPPs"), electricity service suppliers, and transmission companies. NIPPC's current member list can be found at http://nippc.org/about/members/.

transmission risk and transmission need and failed to incorporate those critical elements into its resource plan. The lack of analysis of transmission cost, risk and need associated with the preferred portfolio justifies additional analysis from PGE, and the Commission should not acknowledge the IRP without requiring such additional analysis. Specifically, NIPPC recommends that the Commission:

- Decline to acknowledge PGE's IRP until it incorporates an analysis of transmission need, risk and cost;

- Require all future IRPs to incorporate a calculation of transmission need, risk and costs and include an analysis which balances transmission risk against the costs to ratepayers of acquiring new transmission rights.

- Acknowledge the portion of the IRP related to near term procurement of additional renewable generation capacity with the following modifications and require PGE to:
  - Score bids using conditional firm service, and base any markdown on demonstrated historical curtailment of the service;
  - Consider bids based on non-firm and short-term firm transmission service and to score bids using those products based on historical curtailments; and
  - Apply its deferred transmission rights on BPA's systems in bids in the renewable RFP available to bidders.

B. Direct Access Recommendations:

NIPPC recommends that the Commission reject PGE's analysis with respect to the risks associated with direct access. As explained below, PGE does not perform a rigorous analysis of risks from direct access, but instead offers a capacity calculation in a vacuum that produces an absurd result, suggesting that, if PGE included load from long term direct access customers as part of its IRP (which it currently does not do), PGE should be required to acquire and hold 125 percent of the capacity for servicing such long term direct access load—load that does not want to be served by PGE. The Commission should reject PGE's proposal to reconsider "Guideline 9"[2] and instead re-affirm the Commission's policy that PGE should not plan for load that has exited (or has never been part of) the PGE system in favor of long-term direct access. To the extent the Commission desires to address fundamental issues related to direct access, the proper venue should be the recently opened docket UM 2024, the purpose of which is to explore these issues in detail.

C. RFP Recommendations:

Unlike in past IRPs, PGE is required to abide by the Commission's new competitive bidding rules. The new rules specifically *require* PGE to describe all RFP elements, the scoring methodology, and any associated modeling in its IRP, which needs to transparent and objective. One critical purpose of these new rules is to ensure that prospective bidders in PGE's upcoming RFP have timely notice of and the opportunity for stakeholders to understand what resources PGE actually wants, and, where necessary, for utilities and the Commission to improve the acquisition process itself.

PGE's analysis of the renewable RFP elements, scoring methodology and associated modeling are little different than in past IRPs, and fail to make any reasonable effort to comply with the Commission's new rules. The Commission should not acknowledge this portion of the IRP, and it should require PGE to re-file, at least this portion of the IRP, with the required analysis. This action is necessary because it is

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2 IRP Guideline 9 is entitled "Direct Access Loads" and requires that "electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier." *See Re Commission Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-047 at 6 (Feb. 9, 2007).

critically important to provide the bidding community with as much notice as possible regarding what resources PGE is actually seeking. Further, since this is PGE's first attempt at compliance with the Commission's new RFP rules, the time is now for the Commission to set a precedent regarding the level of detail it expects PGE to provide in its IRP.

Finally, in light of PGE's and the region's near-term capacity deficits,[3] PGE should advance its 2021 capacity RFP to 2020.

II. BACKGROUND

PGE's IRP must be considered in the context of PGE's 2016 Integrated Resource Plan and the subsequent Request for Proposals for Renewable Resources ("2018 RFP"). In approving PGE's shortlist of bidders in the 2018 RFP, the Commission noted that PGE's approach to transmission severely limited the number of projects that were eligible for the 2018 IRP. At the time, NIPPC noted the 2018 RFP included restrictive transmission and interconnection requirements which limited participation, and these should be reviewed after the RFP is completed. Following completion, the Commission found that "transmission deliverability requirements in this RFP did, in fact, limit the shortlist. In particular, section 4.3 of the RFP required bidders to have a schedule that allows transmission service commitments by December 31, 2018."[4]

The Commission also expressed that it intended to:

> more fully address transmission options and limitations in future workshops and proceedings, as the transmission service and generator interconnection queues are affecting the utilities' procurement and how we implement the

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3 *See* Opening Comments of Swan Lake North Hydro, LLC (Oct. 9, 2019).

4 *Re PGE, 2018 RFP for Renewable Resources*, Docket No. UM 1934, Order No. 18-483 at 3 (Dec. 19, 2018).

> state's clean energy goals. We will be asking the utilities to more fully explain the potential issues when they propose an RFP, and we will be asking the IE to more fully and specifically explain transmission issues. We will also address some of these transmission issues in upcoming transmission workshops.[5]

In Staff's analysis of PGE's 2018 RFP, staff expressed concern over the small number of qualifying bids and noted that most were removed on the basis of their failure to meet the transmission requirements in the RFP. Now, despite the Commission's expressed concern with PGE's transmission requirements in Order No. 18-483 and PGE's participation in a series of workshops designed to educate the Commission and Staff on transmission products, PGE is again using transmission requirements to artificially limit the number of viable projects in the next renewables RFP.

III. LEGAL STANDARD

The Commission requires regulated energy utilities to engage in integrated resource planning, along with robust public involvement, and to file an IRP within two years of its last acknowledged plan.[6] Substantively, the Commission requires utilities to: 1) evaluate all known resource options on a consistent and comparable basis; 2) consider risk and uncertainty; 3) select a least cost and least risk portfolio of resources; and 4) create an action plan consistent with the long-run public interest, and Oregon and federal energy policy.[7] The Commission also lists twelve procedural guidelines. If a utility's

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5 *Id.*

6 *Re Investigation into Least-Cost Planning for Resource Acquisitions by Energy Utilities in Oregon*, Docket No. UM 180, Order No. 89-507 (Apr. 20, 1989) (adopting least cost planning that involved public involvement).

7 *Re Commission Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 (Jan. 8, 2007) (establishing IRP Guidelines, including Guideline 13, which requires utilities to identify a proposed acquisition strategy

IRP satisfies the Commission's substantive and procedural requirements and seems reasonable, the Commission "acknowledges" the IRP. Acknowledgement means that the Commission finds the utility's preferred portfolio is reasonable at the time of acknowledgment, but does not guarantee favorable ratemaking.

Least-cost planning was originally established to "involve the Commission, the customers, and the public prior to the making of resource decisions rather than after the fact."[8] The Commission envisioned a process where "all of the options available for providing service are considered" and "the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs."[9] Despite its name, the Commission stated, "[a] resource strategy that offers the lowest expected costs may not be best" and that "[i]f no resource strategy offers the lowest expected costs and lowest variance of costs, then the utility should explain its balancing of those two characteristics in selecting the best strategy."[10]

Although PGE's previous three IRPs have all been acknowledged by the Commission, the Commission has included several conditions that remain relevant in considering whether PGE's current IRP complies with the Commission's Guidelines. For example, upon acknowledging PGE's 2009 IRP, the Commission directed PGE to consider purchasing unbundled renewable energy certificates ("RECs") and other

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and assess advantages and disadvantages of utility owned generation as compared to PPAs); *Re Commission Investigation into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-047 (Feb. 9, 2007) (updating IRP Guidelines to include an inadvertently omitted guideline).

8 Docket No. UM 180, Order No. 89-507 at 3.

9 *Id.* at 2.

10 *Id.*

alternatives to physical compliance to meet its renewable portfolio standard ("RPS") compliance goals.[11]

Likewise, when the Commission acknowledged PGE's 2013 IRP, it again directed PGE to develop and evaluate multiple RPS compliance strategies, including alternatives to physical compliance.[12] The Commission directed PGE to work with Staff and stakeholders to explore options to model environmental compliance, and to convene a series of workshops to examine PGE's load forecast and portfolio modeling methodologies.[13] The Commission further directed PGE to conduct a comprehensive analysis of all flexible capacity resource options.[14] Finally, the Commission suggested PGE expand its consideration of market purchases, energy efficiency, demand response, and distributed generation in its next IRP.[15] As outlined below, PGE has not credibly adhered to the basic IRP Guidelines or these past IRP flaws.

Finally, in PGE's most recent 2016 IRP, the Commission initially acknowledged PGE's IRP except for PGE's action item to issue a renewable RFP, and directed PGE to submit a revised renewable action plan.[16] Among other things, the Commission required PGE to before filing its next IRP, perform a study to look at the risks associated with

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11 *Re Portland General Electric Company, 2009 Integrated Resource Plan*, Docket No. LC 48, Order No. 10-457 at 29 (Nov 23, 2010).

12 *Re Portland General Electric Company, 2013 Integrated Resource Plan*, Docket No. LC 56, Order No. 14-415 at Appendix A at 2 (Dec. 2, 2014).

13 *Id.* at 5-6.

14 *Id.* at 12.

15 *Id.* at 5-6.

16 *In re Portland General Electric Company, 2016 Integrated Resource Plan*, LC 66, Order No. 17-386 at 1 (Oct. 9, 2017).

direct access, and to review transmission issues.[17] In subsequently acknowledging the revised renewable action plan, the Commission imposed a number of additional conditions including that PGE address certain RFP design and scoring concerns and provide better descriptions.[18] Following that IRP, the Commission then engaged in its rulemaking process to improve the RFP process.[19]

IV. TRANSMISSION COMMENTS

A. PGE Has Submitted a Resource Plan - Not an Integrated Resource Plan Because PGE Does Not Adequately Analyze Transmission

PGE's analysis purports to analyze transmission, but falls short of its obligations to the Commission and its ratepayers. PGE's transmission analysis is ineffectual, because in considering transmission, PGE simply assumes that all resources are one wheel away from PGE and that the transmission cost is set at the BPA rate. By making these simplistic assumptions—that the transmission need and cost of all resources is the same—PGE is able to avoid any of the hard work needed to develop the actual transmission cost and risk of any particular portfolio of generation resources. In fact, PGE has not developed any data related to the cost and risk of different transmission solutions or undertaken any analysis is an effort to optimize its existing (or future) transmission portfolio. The information that PGE does provide related to transmission is uninformative as it does not meaningfully identify the transmission cost and risk among different generation resources or distinguish the costs and risks associated with the

17 *Id.*

18 *In re Portland General Electric Company, 2016 Integrated Resource Plan*, LC 66, Order No. at 1-2 (Feb. 2, 2018).

19 *In re Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources*, Docket No. AR 600, Order No. 18-324 (Aug. 30, 2018).

different portfolios. In failing to fully consider transmission need, cost, and risk, PGE falls short of its obligation to the Commission and its ratepayers. PGE failed to fully discover—let alone disclose to the Commission—the cost, risk and uncertainty of the resource options it considered. In the absence of evaluation of transmission cost and risk, there is also no way to determine whether the preferred portfolio or the action plan represents the least cost and least risk portfolio of resources consistent with the long-run public interest.

To its credit, PGE has analyzed most of the key elements to an IRP. PGE has considered what it calls the Planning Environment and attempted to forecast market trends, state and Federal policy changes technology trends and changes to the regional wholesale electric market. PGE has attempted to consider the whole range of uncertainty associated with future natural gas prices, carbon prices, wholesale electricity prices, and hydro conditions in the Pacific Northwest. Likewise, PGE has applied a suite of forecasts and models to its forecasts for its load, its capacity need, its energy need, and its flexibility need together with sensitivities for all of those topics. For potential generation resources, PGE explored in detail the associated economics including fixed, variable and integration costs and for each developed a value for the associated energy, capacity and flexibility. PGE then took all this information and developed a set of portfolios combining different types of generation, located in different resource zones and analyzed the performance of those portfolios under various futures ultimately developing its "preferred portfolio."

NIPPC recognizes the challenges associated with incorporating transmission availability into the IRP process. PGE also clearly understands the scope of that challenge. As PGE notes, transmission rights may already be controlled by a project developer and not publicly known, so any quantity of transmission posted as available by BPA would not necessarily capture the full capability of a generation resource to reach PGE's system. When pressed on its failure to consider transmission in developing its portfolios, PGE responded as follows:

> PGE considers all of these proxy resources in its portfolio analysis to identify a preferred portfolio. While the preferred portfolio provides insight as to how future resource procurement might best balance cost and risk, PGE does not interpret the preferred portfolio as a precise directive of specific resources that must be acquired. The Action Plan is designed to allow PGE to pursue opportunities to meet customer needs in a way that is consistent with the preferred portfolio, but also allows for flexibility should the resources available in the market differ from the proxy generic resources modeled in the IRP in terms of cost and/or performance. Accordingly, it would be inappropriate to limit a quantity of proxy resources available from a specific region in IRP analysis based on an assumed quantity of transmission available transfer capability (ATC). Resources made available to PGE in a subsequent RFP are likely to differ in location, performance, technology, and transmission and interconnection from those proxy resources studied in the IRP.[20]

In other words, PGE considers transmission irrelevant in the IRP because when it comes time to issue an RFP, PGE will consider specific proposals from generators whether or not they are located within one of the resource zones identified in the preferred portfolio. But given the depth of research and analysis PGE has proven it is capable of performing across a wide range of categories, it is perplexing that PGE has completely failed to gather any data or conduct any analysis of transmission at every stage where transmission is important.

[20] Attachment A (PGE Response to NIPPC Data Request No. 016).

Instead of integrating transmission cost, need and risk into its baseline assumptions used to develop its scenarios or incorporating transmission cost, need and risk into scoring each of the portfolios as part of its reach for a preferred portfolio, the IRP simply assumes that transmission service will be available at BPA's published tariff rate. BPA has declared repeatedly that transmission in the Northwest is increasingly constrained and that BPA will no longer build transmission to solve congestion on its system—in large part because the cost of new transmission lines is too expensive for Northwest ratepayers—including PGE's.[21]

In the IRP, PGE determines its need for capacity, energy, renewable energy and flexibility. PGE makes no effort, however, to determine, analyze or disclose its actual need for new transmission. And PGE has made no effort to analyze how it might use its existing portfolio of generation to integrate additional generation resources. PGE needs sufficient capacity on BPA's system to meet its peak demand plus an additional margin.[22] Every other hour of the year—outside of PGE's peak load hour—some quantity of that transmission is not needed. PGE currently has long term firm transmission rights associated with renewable generation projects which have a capacity factor of approximately 32.7%.[23] The other 67.3% of the time, those long-term firm transmission

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21 Attachment B (BPA Administrator letter to region re south of Alston), available at https://www.bpa.gov/Projects/Projects/I-5/Documents/letter_I-5_decision_final_web.pdf.

22 There are options in which PGE would not need BPA transmission, but PGE has elected not to consider those in this IRP. For example, PGE accept delivery at the PACW.PGE point of delivery, or acquire generation in its service territory. NIPPC has not reviewed and is not challenging the reasonableness of these PGE decisions in its IRP.

23 PGE 2019 IRP Sec. 5.2.1.

rights sit idle. PGE could have developed a renewable resource portfolio that took advantage of diversities in generation profiles between different types of renewable generators in different geographic areas that would have optimized that existing transmission portfolio. Instead PGE simply proposes that new renewable generation (with a capacity factor in the range of 32.7 to 42.9%)[24] must have firm transmission rights for at least 80% of their nameplate capacity. If utilities like PGE insist on long term firm transmission service for renewable generation projects, then the region will need to invest in a hugely expensive redundant transmission system with transmission capacity that sits idle much of the time. Moreover, this expectation is in direct conflict with BPA "shifting their approach away from utilizing new construction to meet changing transmission needs, and thus it is unlikely to see increases in the amount of ATC available for purchase," an entity upon which PGE is dependent for transmission.[25] Instead of ignoring transmission, PGE should have attempted to develop and analyze generation portfolios that maximize the use of PGE's existing transmission portfolio.

When defining the generation portfolios it would analyze, however, PGE simply assumed that transmission would be available at the published tariff rate. This assumption ignores the reality that existing transmission constraints limit the quantity of generation that can be exported from some renewable resource generation zones unless costly and long lead time investments are made in new transmission assets. Without analyzing the transmission availability and cost associated with each of the portfolios is studied, PGE (and its ratepayers and the Commission) have no insight into whether the

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24 *Id.* at 134 Table 5-5.
25 *Id.* at 146.

preferred scenario or one of the other scenarios actually represents a viable least cost/least risk option to meet for PGE's needs.

B. PGE's Interim Transmission Addendum Is Inadequate and Should Not Be Acknowledged

Despite the concerns regarding transmission that the Commission expressed in Order No. 18-483 and more than adequate time to develop a serious transmission plan, PGE cobbled together the Addendum in an effort to paper over its complete failure to provide the Commission with the information it had indicated it would want in future IRP processes. In lieu of undertaking any effort to determine its transmission need and the cost and risk of transmission associated with its preferred portfolio, PGE has instead proposed a five-year transmission "approach" for renewable resource procurement processes between 2019 and 2024. This Addendum to its IRP proposes an "Interim Transmission Solution," which essentially boils down to a proposal to accept some conditional firm transmission service as qualifying to support bids into a future RFP for renewables in 2020—although scored at an unknown penalty to long term firm service. Under PGE's proposal, new procurement of renewable resources puts the onus on bidders to include transmission service from their project to PGE's system using either long term firm point to point or one of two types of conditional firm service and by doing so, rejects, out of hand arguably one-half of BPA's conditional firm service (i.e., conditional firm defined by designated conditions). Bidders would be required to provide transmission service for 80% of a project's installed capacity.

NIPPC appreciates that PGE has finally moved off its longstanding opposition to conditional firm transmission service. Allowing bidders to secure conditional firm to support their bids is a small tentative step in the right direction. NIPPC, however, believes that even more flexible transmission options could be considered—and these other options could lead to significantly lower costs for with very little increased risk.

C. Transmission Need

As a threshold matter, NIPPC urges the Commission to require PGE to demonstrate its need for additional transmission for renewable resources. PGE's IRP currently predicts an annual peak load forecast in 2020 of between 3426 and 3450 MW.[26] At the same time, PGE currently controls [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] MW of transmission capacity across BPA's system[27] plus additional transmission on other utilities' systems. Of the transmission it controls, [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] MW is currently in deferral status.[28] PGE appears to have more than enough transmission to meet its forecasted loads. In fact, in its IRP PGE has not asserted that it needs new dispatchable resources to meet its load service obligations. Rather PGE's IRP indicates that it seeks to acquire new RPS resources. Instead PGE's preferred portfolio identifies a need for a total of 542 MW of

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26 *Id.* at 268

27 *See* Attachment A (PGE Response to NIPPC Data Request No. 010 Attachment A_Confidential).

28 *See* Attachment A (PGE Response to NIPPC Data Request No. 010 Attachment A_Confidential). BPA's transmission customers have an opportunity to delay the start date of their transmission service. The process, called "Extension of Commencement of Service" allows a transmission customer to put its transmission service request into "deferral status". The customer has the option of delaying the start of that reservation request for up to five years (in one year increments). While the transmission provider can sell that capacity in the short term market, because the deferred capacity is committed to another customer, it cannot be sold on a long term basis to another customer.

new wind generation from Washington, Montana and the Columbia Gorge.[29] Applying the proposal from PGE's Transmission Addendum would require PGE ratepayers (through the RFP) to gain control of an additional 433.6 MW of transmission service across BPA's system (80 percent of the 542 MW preferred portfolio).[30] NIPPC urges the Commission to require PGE to explain why its existing transmission portfolio—perhaps supplemented with short term and/or non-firm transmission service cannot be deployed to integrate the proposed new renewable resources and also require PGE to justify its need for additional transmission to support acquisition of new renewable generation.

The presumed purpose of the renewables purchase portfolio is to acquire RPS resources economically. As noted above, the purpose of the proposed acquisition is not to obtain dispatchable resources needed to meet PGE's resource adequacy obligation to serve customer demand. Instead, PGE's portfolio of renewable generation resources will be used to displace output from other more expensive and carbon emitting dispatchable resources. Those dispatchable resources which are being displaced by the cheaper, carbon free resources already have transmission rights across BPA's system. Ideally, PGE would be able to use its dispatch desk to optimize its existing portfolio of transmission rights on BPA's system to deliver renewable resources to load (when required) or to the market when PGE's load demand is less than the renewable generation output. So instead of requiring its ratepayers to absorb the cost of additional long-term firm point to point rights across BPA which are used a fraction of the time, the Commission should require PGE to consider alternative transmission products. By

29 Attachment A (PGE Response to NIPPC Data Request No. 021).
30 PGE 2019 IRP at Addendum at 10.

failing to consider additional transmission products, PGE has failed to fulfill its obligations to prepare an Integrated Resource Plan and will fail in its obligation to provide service to ratepayers at least cost and risk.

D. Transmission cost and risk.

Long term firm point to point transmission service is the most expensive transmission service and also the most reliable. In the event BPA needs to curtail transmission service—which usually occurs when there is unexpected congestion or service interruptions occur—long term firm point to point service is curtailed after most other types of transmission service (such as non-firm or short-term service). BPA offers conditional firm service at the same price as long term firm service—even though the quality of service may be lower. By proposing to require bidders to obtain long term transmission service for 80% of the capacity bid into the proposed procurement process, PGE is ensuring that its customers will pay the highest possible price for transmission service associated with the additional renewable resources. As noted above, PGE is not relying on the proposed procurement of new renewables to meet its peak demand; rather it is seeking to add economic renewable energy to meet its RPS requirements. NIPPC suggests the calculus of adding renewable generation sources that are effectively economy energy purchases should include consideration of whether less costly transmission solutions are appropriate. PGE should consider more economic transmission solutions (consisting of short term and non-firm transmission products) even if those alternatives lead to a higher risk of curtailment of generation. In short, NIPPC asks PGE to balance the cost of transmission service with the risk of curtailment. While the Addendum purports to consider cost shifts to ratepayers it does not appear to have considered other alternatives that may provide service of sufficient reliability but at dramatically reduced cost.

PGE suggests that part of its purpose in pursuing the Interim Transmission Approach is to learn. NIPPC agrees that a purpose of any provisional program should be learning and experience. However, the primary purpose of this IRP and the subsequent RFP should be to acquire the least cost and least risk resources to serve PGE's load, which should include evaluation of even more flexible transmission plans. PGE should undertake to implement or modify necessary systems and business processes to appropriately identify and track the impacts of the program. By testing and improving these new processes, PGE can more effectively learn from the provisional program and make adjustments or refinements to increase effectiveness while actively managing the associated risks.

The opportunities for learning under the proposed plan are actually quite limited because conditional firm functions essentially the same as long term firm point to point transmission service. Long term point to point service is often curtailed due to transmission outages or other reasons—both planned and unplanned. Curtailments of conditional firm might occur more frequently (conditional firm would be curtailed before long term firm) but the necessary response by PGE’s operations would be identical. If PGE really wanted to learn how to integrate renewables without relying on long term transmission rights (especially since it appears that those rights may actually be available in the absence of costly upgrades to the transmission system), then its interim transmission approach would have proposed supporting some percentage of its renewable procurement on a mix of short term firm and non-firm transmission. Instead of procuring long term firm transmission for 8760 hours a year which would likely be used only a fraction of the time, PGE could tailor its transmission purchases to the likely generating profile of the particular generation project instead of paying for premium service that would not be used most of the year.

NIPPC is also concerned with the magnitude of the discount PGE proposes to apply to resource bids based on conditional firm service. PGE proposes to discount bids using conditional firm service based on the maximum number of hours of curtailment. NIPPC suggests that any discount applied to conditional firm should be based on the historical number of actual hours of curtailment of conditional firm service on the impacted path. Because long term firm point to point is also curtailed under certain conditions, the measure of any increased risk of conditional firm compared to long term firm should be the number of hours that conditional firm is curtailed less the number of hours that long term firm service is curtailed. Furthermore, BPA has signaled that for the foreseeable future, conditional firm may be the only service that is available. While some project developers may have existing contracts with BPA that could support a bid using long term firm point to point, increasingly conditional firm transmission service will be the only long-term service that BPA will be able to sell. In this case, why would PGE discount bids from projects based on conditional firm service. NIPPC also suggests that a discount may not be appropriate given the expectation that PGE would be able to use its portfolio of existing transmission rights (and rights that are currently in deferral status) to "firm up" conditional firm service.

NIPPC is also concerned with other key aspects of its Transmission Addendum, including that: 1) PGE has not provided any explanation for the rationale behind requiring eligible transmission service of at least 80% of the maximum output of the facility; 2) PGE is limiting consideration of Conditional Firm based on "number of hours" of curtailment while completely refusing to consider Conditional Firm based on designated system conditions, a service that BPA offers; and 3) that any cost or risk associated with Conditional Firm service (or other transmission products) may be counted twice or more by PGE.

PGE proposes that the RFP process will consider cost/risk implications through the scoring methodology and contract requirements. For the scoring methodology, there is a risk that the adjustments proposed by PGE may result in double counting. The proposal identifies the following adjustments:

(1) Adjust the RECAP model to reflect the impacts that less than 100% firm transmission will have on the capacity contribution of the resource. This will take into consideration the type of transmission service, the type of resource, and output profile.[31]

(2) Non-price scoring will consider "non-quantifiable aspects." The example offered is the difference in long-term availability of transmission when evaluating CF Reassessment and CF Bridge service.[32] How is this not addressed in the first adjustment? What other "non-quantifiable aspects" will PGE consider?

PGE explains that it will also require "more robust contract terms" in order to hedge against increased deliverability risk.[33] Greater explanation of what this could entail would be informative. In addition, PGE has indicated that it will "not accept an assignment by default proposal from bidders."[34] Greater detail in terms of the value of assigning transmission rights to PGE, as well as the management responsibility, and

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31 PGE 2019 IRP at Addendum at 6.
32 *Id.*
33 *Id.*
34 *Id.* at 7.

allocation of revenues that result from resale of unused transmission is needed. Moreover, understanding how PGE will include this element in the scoring would be instructive.

The proposed business processes appear to add again previously considered costs and risks. For example, PGE identifies the "readily identifiable impacts" associated with purchasing short-term transmission, the need for additional reserves, forecast updates, net purchases and sales of transmission and power.[35] How are these elements not addressed in the RECAP modeling and the anticipated "more robust contract terms"?

NIPPC encourages the Commission to make changes to PGE's proposed provisional transmission program described in its Transmission Addendum. It makes sense to have a monitoring and reporting program, however, it appears that PGE plans to evaluate the impact that *individual resources* may have, whereas, resources, both generating and transmission, are typically managed on a system basis. It would be helpful to understand how, within the context of a combined portfolio, PGE will evaluate resources with the identified reporting metrics. Also, it is not clear why the "external policy changes" should be considered differently for resources secured as part of this provisional program. The sorts of policy changes, (EIM, EDAM, BPA's cluster study process) will impact the entire market. Finally, PGE's proposed timing of resources participating in the "interim transmission solution" appears impossible. PGE proposes December 31, 2020 as the deadline for securing and executing a Precedent Transmission Service Agreement (PTSA) with BPA, however that will also involve satisfying all of the

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[35] *Id.*

necessary requirements involved in securing transmission service from BPA (Conditional Firm) or negotiating special transmission contract terms with PGE. This timeframe should also be adjusted.

V. DIRECT ACCESS COMMENTS

A. The Commission Should Continue to Require that PGE Exclude Long-Term Opt-Out Direct Access Customers from Its Capacity Planning Pending Action in Docket UM 2024, Investigation into Long Term Direct Access Programs

As noted by PGE in its 2019 IRP, the Commission adopted as IRP Guideline 9 the requirement that "[a]n electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier."[36] The Commission order requires the exclusion of all of PGE's long-term direct access ("LTDA") customers from capacity need assessments, portfolio analysis, and action plans within the IRP. There is no confusion on these requirements, and PGE's 2019 IRP appears to comply with all aspects of the resource needs, including energy, capacity, renewable portfolio standard, and flexibility needs.[37]

While PGE has not included long-term direct access in its 2019 IRP capacity assessments, PGE's IRP claims that continued application of Guideline 9 could introduce additional risk to cost of service customers, and notes that it "has and will continue to advocate for regulatory solutions that share the responsibility for resource adequacy and reliability across all customers."[38]

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[36] PGE 2019 IRP at 123 (citing Docket No. UM 1056, Order No. 07-047 at 6 and Docket No. UM 1056, Order No. 07-002).

[37] *Id.* at 124.

[38] *Id.* at 126

PGE's risk analysis in its IRP for the level of resource adequacy that would be necessary to support direct access load—should PGE be obligated to provide such support—is fundamentally flawed. As a preliminary matter, NIPPC wants to emphasize that the Northwest region will soon be facing a significant capacity deficit, largely due to the retirements of coal generation. This will require the investment of new capacity resources, and there are legitimate questions about future resource adequacy. NIPPC intends to be part of the regional discussion about how to ensure that the region's capacity and resource adequacy needs are met. Thus, NIPPC's comments should in no way be seen as minimizing the seriousness of this issue, but instead focused on PGE's lack of support in this IRP for its claims that there any resource adequacy problems associated with direct access.

If PGE truly believes that Guideline 9 introduces additional risks, then the proper venue to consider such as issue related to the long term direct access programs is in the recently-opened Petition for Investigation Into Long-Term Direct Access Programs in Docket UM 2024.[39] Docket UM 2024 calls for a comprehensive review of the direct access programs, expressly including reviews of program structure to avoid unwarranted cost shifting and investigation of the potential benefits and potential harms of direct access. Docket UM 2024 will allow all interested parties and the Commission to consider modifications to the direct access program in ways that may reduce risks and

[39] *See Re Alliance of Western Energy Consumers*, Docket No. UM 2024, Order No. 19-271 (Aug. 15, 2019).

costs for all parties concerned.[40] Given the opportunity for all parties to specifically address the potential benefits and harms to PGE's cost of service customers in Docket UM 2024–and given that PGE is not seeking to change the application of Guideline 9 in this IRP proceeding, the Commission should decline to make any changes to the application of Guideline 9 at this time.

B. The Commission Should Not Acknowledge or Endorse PGE's Study of Risks Associated with Direct Access

In its order addressing PGE's 2016 IRP, the Commission acknowledged PGE's request to study the risks associated with direct access.[41] PGE does not appear to have performed any such study. Instead, PGE provides a very limited analysis based on extreme and inaccurate assumptions to reach conclusions that are absurd. For example, PGE submits in Table 4-15 that direct access would require PGE to acquire and maintain in rate base new incremental capacity in amounts substantially in excess of total direct access load in order to ensure system reliability for customers purchasing power from third parties.[42] The suggestion that PGE would need to acquire *a net increase (i.e., 125%) in capacity* as a backstop for direct access *relative to its total direct access load*—

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[40] For example, PGE notes in its IRP that it currently cannot preferentially provide reliability and flexibility to cost-of-service supply customers over direct access customers. This issue could be addressed in UM 2024.

[41] *See Re PGE 2016 IRP*, Docket No. LC 66, Order No. 17-386 at 19 ("Based on the recommendations of Staff and stakeholders we require the following studies to inform PGE's next IRP: … Risks Associated with Direct Access.") (Oct. 9, 2017).

[42] For example, PGE's Table 4-15 concludes that PGE would have an incremental capacity need of 373 MW to meet reliability obligations for a 300 MWa direct access program.

when such direct access load purchases its power from other parties—strains credibility and should be dismissed outright.

PGE claims that it "examine[d] sensitivities in resource needs related to … long-term direct access programs,"[43] but undertook no such sensitivity study, as evidenced by their data responses requesting information on such sensitives.[44] PGE limited its direct access analysis to projections for one year, 2025, and only considered potential capacity needs assuming full subscription of its long term direct access program under currently existing program caps.[45] PGE's program has never been fully subscribed, but PGE neither evaluated capacities below full subscription, nor consider the possibility of expanded program caps, or other "sensitivities."

Further, PGE does not provide any sensitivities or scenarios as to whether it will ever be called upon to act as a supplier of last resort for returning long term direct access customers. The existing direct access rules provide that a customer returning from direct access can take service from PGE based on market-priced purchases, along with an extra fee, to ensure providing service to returning direct access customers does not create a cost shift that impacts other customers. PGE has not provided any analysis of the likelihood that a given direct access customer would ever return to PGE's system, let alone all of them at once. PGE has also not provided any analysis of the likelihood that it would not be able to purchase power on the open market to service a returning customer.

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[43] PGE 2019 IRP at 73.

[44] *See e.g.*, Attachment A (PGE's Response to NIPPC Request No. 022-026).

[45] As noted in PGE's IRP at 125, PGE's currently existing program caps are 300 MWa for the existing long-term direct access program, and 119 MWa for the large new load direct access program that has been approved but is not yet in place.

PGE's analysis also is fundamentally flawed because it starts from the factually-incorrect premise that electricity service suppliers ("ESSs") provide no contribution to regional resource adequacy. PGE criticizes ESSs' use of firm liquidated damages ("firm LD") contracts to procure supply; firm LD contracts sourced from outside of PGE's BA do in fact contribute to resource adequacy within PGE's BA. To the extent such firm LD contracts are sourced by power outside of the Pacific Northwest resources, such as from the CAISO, such firm LD contracts support the broader regional resource adequacy needs. PGE and other investor-owned utilities also often use the very same standard form agreements for firm LD contracts to meet their own load service needs and support PGE's own resource adequacy. Direct access customers are contractually required to and are in fact self-supplying their resource reliability to a large extent, and PGE's analysis—which essentially assumes all direct access service is interruptible, energy-only service—is not sufficiently rigorous to merit any consideration by the Commission. As noted above, these issues should be addressed, if at all, in the review the direct access programs in Docket UM 2024. If the Commission determines to require resource adequacy requirements in that proceeding, the sale of such capacity products should also be allowed by ESSs and should not be a product that only PGE may offer.

VI. RFP COMMENTS

Since PGE's last IRP, the Commission adopted its new rules governing competitive bidding.[46] Under these rules, for any acquisitions over 80 MW, PGE is

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46 *In re Rulemaking Regarding Allowances for Diverse Ownership of Renewable Energy Resources*, Docket No. AR 600, Order No. 18-324 (Aug. 30, 2018).

required to clearly express its system need (rather than limit the acquisition to a specific resource).[47] This need must be expressed in detail its IRP including the scoring associated with the acquisition.[48] The goal of these rules is to give notice to prospective bidders and "the opportunity for stakeholders to understand and, where necessary, for utilities and the Commission to improve the acquisition process."[49]

Specifically, PGE's IRP should describe any RFP elements, the scoring methodology, and any associated modeling.[50] The scoring methodology should be transparent and objective.[51] Any non-price scoring criteria must "primarily relate to the resource characteristics identified in the. . . most recent acknowledged IRP."[52] It "must be objective and reasonably subject to self-scoring analysis by bidders."[53] "Non-price factors must be converted to price factors where practicable."[54] Finally, should any of the remaining non-price criteria identify minimum thresholds for a successful bid, those criteria should be converted into minimum bidder requirements.[55]

PGE's proposed RFP is not transparent and does not provide sufficient objective scoring criteria to give adequate notice to prospective bidders as required by the rules. NIPPC submits these comments in an effort to improve the resource acquisition process as contemplated by the Commission in its RFP rulemaking. NIPPC supports the

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47 *Id.* at 5, 8.
48 *Id*. at 8.
49 *Id.*
50 OAR 860-089-0250.
51 OAR 860-089-0400.
52 *Id.*
53 *Id.*
54 *Id.*
55 *Id.*

Commission acknowledging PGE's need to acquire 150 aMW and issuing an RFP to acquire new generation; however, the Commission should not acknowledge how PGE plans to acquire the 150 aMW renewable RFP and require that PGE supplement its IRP with additional specificity on its scoring criteria, especially on the non-price criteria. The biggest problem with PGE's proposed resource acquisition is that up to 40%[56] of the score is impossible to evaluate at this point in time because it is not broken up into individual objective scoring allocations and not described in sufficient detail to know if the requirements could be minimum bidding criteria or price factors instead.

PGE's proposed renewable RFP design and modeling methodology provides little detail to prospective bidders and this lack of detail limits the Commission, Staff and stakeholders' ability to first, understand, and second, offer constructive feedback to improve the resource acquisition process. The Commission's new rules require greater specificity earlier in the process and PGE has failed to meet that objective by simply articulating generic factors it will consider in scoring its bids, without offering anything concrete to provide a prospective bidder with notice of PGE's acquisition. PGE provided far less detail than NIPPC understood would be provided when it helped develop the new RFP rules. As PGE's discovery responses demonstrate, PGE takes the position that it

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56 PGE has proposed a 60% price and 40% non-price score. NIPPC believes that this split is inappropriate and places too much emphasis on non-price scoring factors. This will allow PGE to use non-price factors to help adjust the RFP results toward its favored resource rather than the least cost and least risk option. NIPPC understands that PGE will conduct additional sensitivities in its request for RFP approval. Attachment A (PGE Response to NIPPC Request No. 005). Therefore, NIPPC will raise its concerns regarding the 60/40 price/non-price split when PGE files its RFP rather than in this IRP, and will likely recommend that PGE use an 80/20 price/non-price split.

need not supply more than very high level information on its upcoming RFP.[57] The level of analysis is basically unchanged from what one would have expected before the administrative rules were adopted.

C. PGE Fails to Provide Any Detail on its Non-Price Scoring Methodology Beyond What a Market Participant Already Knows

PGE's fails to meet the Commission's minimum requirements with regard to its non-price scoring factors because: 1) the non-price factors do not primarily relate to the resource characteristics identified in the IRP; 2) PGE fails to provide adequate detail to determine whether the factors can be converted to a price factor or a minimum bid requirement; and 3) PGE fails to articulate objective criteria that is reasonably subject to self-scoring by bidders.

The non-price factors constitute a significant share of the overall score and PGE's vague descriptions fall woefully below the standard set by the Commission's new rules. The non-price factors include: 1) Project Development Criteria intended to score "the likelihood that a project supporting a bid will be placed in commercial service;" 2) Project Physical Characteristics intended to score "the physical characteristic risks of the bid products;" 3) Project Performance Certainty intended to score "how well the bid product matches PGE's system operating needs;" and 4) Credit Evaluation intended to score "the creditworthiness of the bidder."[58]

First, PGE's "<u>Project Development Criteria</u>" does nothing more than state the obvious and unremarkable fact that such factors may affect whether a particular project is

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[57] *See* Attachment A (PGE Response to NIPPC Request No. 054-57).

[58] PGE 2019 IRP at 371-378.

likely to be placed in commercial operation. PGE says it will *consider* the *status* of required permits, licenses and environmental studies; it will *consider* the experience of the project team; it will *consider* the *method* and *status* of financing; it will *consider* site control; it will *consider* the *status* of equipment contracts and sale or PPA price structure; and it will *consider* the project life and extension options.[59] This offers no additional information on bid scoring criteria that what a market participant already reasonably knows about what factors weigh into the likelihood of success for any particular project.

These Project Development Criteria do not primarily relate to the resource characteristics identified in this IRP. While the rules do not require that the non-price factors relate to resource characteristics, *per se*, the rules do indicate that the non-price score should "*primarily*" relate to resource characteristics.[60] The Project Development Criteria relate to the characteristics of the project team (e.g., their "experience") or the status of development efforts such as permitting, project financing, site control, equipment, and other contractual characteristics. These factors have no bearing on the characteristics of the resource itself. In doing this, PGE provides no explanation as to why PGE included these criteria as non-price factors, rather than accounting for these factors someplace else in its scoring methodology.

Many of these Project Development Criteria may more appropriately be classified as minimum bid criteria or maybe converted to price factors, but PGE does not sufficiently describe any of its non-price scoring criteria to enable the Commission, Staff

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59 *Id.* at 371.

60 OAR 860-089-0400 ("Non-price scores must, when practicable, primarily relate to resource characteristics identified in the electric company's most recent acknowledged IRP Action Plan").

and stakeholders to evaluate whether the non-price factors may be more appropriately converted to a price score or a minimum bid criterion. The rules require that non-price factors be converted to price factors where practicable and if the non-price factors seek to identify minimum thresholds for a successful bid and may be readily converted into minimum bid criteria, then it must be converted into minimum bid criteria.[61] It is not clear whether PGE intends to reject a bid outright if, for example, it has not even applied for a permit at the time it submits a bid or if it is only in negotiation with a landowner but has not secured site control. There may be some minimum level of project development work that PGE intends to require, and these types of project milestones are easily converted to minimum bid criteria. Yet, PGE still lists these criteria as an amorphous aspect within its non-price scoring category and asserts that any decision regarding whether it should be converted to a minimum threshold is "outside the scope of this proceeding."[62]

The goal of the Commission's new rules was to provide more information on utility RFPs earlier in the procurement process to give bidders notice. PGE's amorphous Project Development Criteria provides no details to potential bidders regarding how far along their project needs to be to receive the highest score. Development efforts can take years to implement and if PGE waits until the last minute to provide any notice about minimum thresholds for eligibility, then many if not most potential bids will not qualify and there will be no improvement from PGE's last IRP where only a few bids made the final shortlist.

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61 *Id.*

62 Attachment A (PGE Response to NIPPC Request No. 054).

Additionally, even if there is no minimum threshold requirement for the Project Development Criteria, PGE does not articulate any objective criteria for scoring such factors. As the rules clearly provide, PGE's job in designing its RFP non-price scoring criteria is to design criteria that is "objective and reasonably subject to self-scoring."[63] Specifically, PGE does not tell bidders objectively how much of a lower score they will receive should their required permits, licenses, or environmental studies still be in progress, or how their score will be affected if the project team has never successfully completed a project, or if the project team has completed few projects, or many projects. PGE fails to articulate how the method of financing affects the score, or how the status of financing affects it. There is no indication of how site control, equipment contracts, sale or PPA structures, or project life and extension options affect the score. There is no dispute that factors such as these have some impact on the likelihood for a project to become commercially operational, but PGE provides utterly no indication of any objective scoring criteria.

Objective scoring criteria is required to be produced in the IRP under the new rules because otherwise the requirement that the RFP "reflect any. . . scoring methodology. . . described in the Commission-acknowledged IRP"[64] would be rendered meaningless, and the Commission's efforts to provide notice to potential bidders and an opportunity for stakeholders to understand and improve the process would be fruitless. Here too, PGE asserts that its scoring criteria is "outside the scope of this proceeding."[65]

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63 OAR 860-089-0400.
64 OAR 860-089-0250.
65 Attachment A (PGE Response to NIPPC Request No. 054).

However, PGE's position is directly inconsistent with the rules because its RFP cannot reflect the scoring methodology described in the IRP if the IRP contains no methodology. As it stands now, PGE's IRP contains no methodology, and thus the RFP would need to contain no methodology to be consistent with the IRP.

Second, while PGE's "Project Physical Characteristics" generally relate to physical and operational characteristics of the project, there are still some factors that primarily relate to the *status* of the project. Here, like the project development factors just discussed, PGE also indicates that the *status* of the interconnection and transmission will impact the non-price score in addition the transmission characteristics and curtailment obligations, any remedial action schemes, the engineering reliability characteristics, and the resource fuel availability confidence.[66] Since the *status* of interconnection or transmission processes do not primarily pertain to the resource characteristics PGE should consider evaluating them in a different part of the RFP.

The Project Physical Characteristics may also be subject to classification as minimum bid requirements but PGE has not provided sufficient detail. The *status* of interconnection and transmission could be converted into minimum bid requirements, but here as with the factors above, PGE has not provided any indication of whether it will require that any particular milestone be achieved as a minimum bid requirement.[67] For example, PGE says it has not established minimum bid requirements for interconnection and asserts that such requirements are "appropriately addressed in an RFP proceeding."[68]

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66 PGE 2019 IRP at 371.
67 Attachment A (PGE Response to NIPPC Request No. 055).
68 Attachment A (PGE Response to NIPPC Request No. 036).

However, PGE also appears to contemplate that it will require that a project supporting a bid will have reached the facilities study.[69] Therefore, it appears that PGE will require a facilities study as a minimum bid criterion. If that is the case, PGE should specify so now in order to give the Commission, Staff, and stakeholders the opportunity to comment on that minimum requirement and improve the process. The remainder of the Project Physical Characteristics listed may also be capable of being classified as minimums, but PGE has not provided sufficient detail to understand and recommend whether the factors should be classified as minimums.

PGE simply provides no objective indication of the weight of any particular factor in the grand scheme of the bid. The most detail PGE offers is that projects "will receive additional points" if PGE is able to use the project as a credit for its obligation to support existing remedial action schemes.[70] However, this level of detail provides no notice to potential bidders except maybe that they ought to consider this particular item. The number of *additional points* is not specified, and the weight of this factor in relation to other factors is completely unknowable. PGE has not provided any objective scoring criteria regarding how these criteria factor into the overall calculus.

Third, PGE's "<u>Project Performance Certainty</u>" category again simply lists factors that PGE will *consider* in its non-price scoring including firmness of energy, scheduling, contract/resource start date, guarantees, and deviations from form product term sheet.[71] It

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69 Attachment A (PGE Response to NIPPC Request No. 043) ("PGE intends to ensure that the interconnection costs included in the bid are consistent with interconnection facility study results produced by the relevant transmission provider and included within each bid.").

70 PGE 2019 IRP at 371.

71 *Id.* at 371-372.

is completely unremarkable to any market participant that these types of factors may be considered in an RFP, so PGE offers no additional notice to potential bidders about its upcoming RFP. Again here, the weight each of these factors holds is completely opaque. The goal of the Commission's new RFP rules was to encourage transparency, and PGE offers none.

Finally, PGE's "Credit Evaluation" criteria again tends to measure the characteristics of the bidder rather than the resource characteristics and may not be appropriately categorized as a non-price factor. PGE indicates that it will *take into account* the creditworthiness of the bidder including debt to equity ratings, financial ratio analysis, bond risk, tangible net worth, and corporate structure.[72] None of these factors relate to the resource characteristics, but relate to the bidding company. Without any further detail here about what characteristics PGE's prefers, it is impossible for a bidder to know whether it should even try to bid in. PGE may have some number in mind when it says the "debt to equity rating" will be considered. There may be some rating at which PGE will simply refuse to work with a bidder or some number that in combination with other factors such as bond risk or other non-price factors that PGE will consider unacceptable. However, without any other detail, here again, it is impossible to know whether these criteria may be better classified as minimum bid requirements or converted to price factors. PGE has provided no objective way to measure these or any of the other non-price factors discussed above. Therefore, because the non-price factors account for

72 *Id.* at 372.

40% of the overall score, it is not insignificant and PGE should be required to provide further detail to comply with the Commission's newly adopted rules.

D. Price Score

PGE's proposed price scoring methodology and adjustments to prices submitted by bidders also do not provide sufficient detail. While a price score is more easily capable of objective scoring, PGE still leaves significant uncertainty around how it will adjust bid prices. The "[p]rice score must be based on the prices submitted by bidders and calculated using units that are appropriate for the product sought and technologies anticipated to be employed."[73] The Independent Evaluator ("IE") "may authorize adjustments to price scores on review of information submitted by bidders."[74] PGE indicates that prices will be subject to adjustment for costs related to transmission, interconnection, ancillary services, owner's costs, performance assurances, and tax credit carrying cost net benefits. However, PGE does not indicate the source it will use to make those adjustments. In response to data requests, PGE indicates that in making these adjustments, it will rely upon: 1) tariffed transmission service costs at the time of PGE's evaluation; 2) interconnection requirements detailed in the facility study included within each bid; 3) tariffed or forecast ancillary service costs at the time of PGE's evaluation; 4) internally identified owner's costs assumptions; 5) quotes for performance assurance costs; and 6) a forecast of PGE's tax credit utilization.[75] The assumptions underlying

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73 OAR 860-089-0400(2)(a).
74 *Id.*
75 Attachment A (PGE Response to NIPPC Request Nos. 042-047).

these price adjustments should be provided in its IRP because there is a lack of detail regarding how they will be accounted for in the RFP.

E. PGE Provides Nothing to Indicate the Weighting of Individual Factors that Make up the Price and Non-Price Score

The only detail PGE provides in weighting is that it will be a 60/40 split of price and non-price scoring criteria. PGE has not discussed the derivation of this determination, whether it has evaluated other price/non-price allocations, even in light of the Commission's new rule that non-price factors be converted to price factors, where practicable, or as minimum requirements. Should certain non-price factors be pulled out of the non-price score, then the 60/40 split PGE has used historically will make the non-price score even more important than the price score.

Further, within the non-price score and as discussed above, PGE provided no allocation of the individual factors affecting the non-price score. PGE's RFP must reflect the scoring methodology described in the Commission-acknowledged IRP. In this 2019 IRP, PGE had not articulated any non-price scoring methodology which is yet another reason not to acknowledge this part of PGE's IRP.

The Commission should require that PGE supplement its IRP with a revised Appendix J: Renewable RFP Design and Modeling Methodology document and re-evaluate whether to acknowledge the revised documents.

VII. CONCLUSION

NIPPC appreciates PGE's hard work on the IRP and recommends that the Commission acknowledge the IRP, subject to the exceptions listed above.

Dated this 11th day of October 2019.

Respectfully submitted,

Sanger Thompson, PC

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Attachment A

PGE Responses to NIPPC Data Requests

August 6, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 005
Dated July 23, 2019

<u>Request:</u>

Please refer to section J.2.1 "Bid Evaluation Criteria" and J.4 "Final Short List Determination."

a) **Please explain: a. Why PGE selected the 60/40 price/non-price split.**

b) **What additional sensitivity analysis that PGE will perform to determine the sensitivity of scoring results on price and non-price weighting, and whether PGE will study how the ranking of its short-list would be affected by an 80/20 price/non-price split.**

c) **c. Please provide a ranking of the bids in PGE's 2018 Renewable RFP using an 80/20 and 70/30 price/non-price split.**

<u>Response:</u>

PGE objects to this request which calls for new analysis, is overly broad, and seeks information that is not relevant to the subject matter of this docket. The request seeks information from the 2018 Renewable RFP. Without waiving these objections, PGE responds as follows:

A) PGE's proposed price and non-price weighting balances project cost and project risks to identify least cost, least risk resources for customers. A 60 percent price score weighting reflects PGE's intent to prioritize resources of least cost and greatest value to customers. A 40 percent nonprice weighting reflects PGE's intent to also appropriately recognize least risk resources for customers.

Consistent with Public Utility Commission Oregon Order number 91-1383 in UM 316[1], PGE has regularly utilized a 40% non-price score allocation to reflect the implicit risks that are not captured in the price score. PGE believes that it is reasonable and appropriate to balance price and non-price scoring factors with a 60/40 weighting in a future renewable RFP.

B) PGE intends to perform additional sensitivity analysis to determine the sensitivity of scoring results on price and non-price weighting. PGE intends to specifically study 50/50 and 70/30 price, non-price weighting sensitivities. PGE's request for RFP approval will include the specific sensitivities for inclusion in the RFP analysis.

[1] In UM 316 Staff recommended that non-price factors be weighted 30%-50% to appropriately address various risks factors associated with projects.

August 7, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 010
Dated July 24, 2019

Request:

Please provide a copy of the Service Agreement for Point-to-Point Transmission Service executed by the United States Department of Energy acting by and through the Bonneville Power Administration and Portland General Electric Company (BPA Service Agreement 09TX-14507) together with all Exhibits and Tables.

Response:

PGE objects to this request on the basis that it is overly broad, unduly burdensome, and seeks information that is not relevant to this proceeding. Subject to, and without waiving these objections, PGE responds as follows:

Please see Attachment A which identifies the long-term transmission rights executed by PGE's Merchant Function (PGEM). Attachment A contains a table which identifies the transmission provider, the transmission service request number (TSR), service type, point-of-receipt (POR), point-of-delivery (POD), source point, sink point, MW amount, start date and stop date.

Confidential Attachment 010-A_CONF contains protected information subject to Protective Order No. 19-186.

Confidential Pages Redacted

PGE Response to NIPPC Data Request No. 010 Attachment A_Confidential

August 7, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 016
Dated July 24, 2019

Request:

Portland General indicates that it is largely dependent on BPA's transmission system to deliver its resources to load. Portland General also describes BPA's transmission system as increasingly constrained— that on many of BPA's flowgates, there is little to no Available Transfer Capability left for purchase. Portland General describes the transmission constraints on BPA's system as a "growing challenge" as "most of the current and future resources" PGE will acquire to meet load are "located off PGE's system and are likely to require BPA transmission to reach PGE's system." Please confirm that:

a. In its portfolio analysis, PGE assumes that transmission service will be available to deliver the generation resources in the portfolio to PGE's load.

b. PGE's portfolio analysis did not make any effort to analyze whether there was any ATC available on BPA's system to deliver energy from any of the resources described in any of the portfolios.

Response:

PGE objects to this request to the extent that it misleading and seeks information that is not relevant to this proceeding. Without waiving these objections, PGE responds as follows:

a.) As noted on page 148 of the 2019 IRP, PGE assumes in the IRP that off-system generation resources will have access to transmission at BPA rates.

b.) In the IRP, resources are considered as proxies, based on generalized characteristics provided by a third-party consultant.[1] Multiple wind resources are considered in the IRP as geography affects both the intensity and timing of generation.

[1] In the 2019 IRP, these estimates were provided by HDR. Please refer to External Study D. Characterizations of Supply Side Options for more detail.

PGE considers all of these proxy resources in its portfolio analysis to identify a preferred portfolio. While the preferred portfolio provides insight as to how future resource procurement might best balance cost and risk, PGE does not interpret the preferred portfolio as a precise directive of specific resources that must be acquired. The Action Plan is designed to allow PGE to pursue opportunities to meet customer needs in a way that is consistent with the preferred portfolio, but also allows for flexibility should the resources available in the market differ from the proxy generic resources modeled in the IRP in terms of cost and/or performance. Accordingly, it would be inappropriate to limit a quantity of proxy resources available from a specific region in IRP analysis based on an assumed quantity of transmission available transfer capability (ATC). Resources made available to PGE in a subsequent RFP are likely to differ in location, performance, technology, and transmission and interconnection from those proxy resources studied in the IRP.

Additionally, constraining resource availability on the basis of transmission would require speculation to resolve differences between PGE's IRP modeling and the physical and commercial qualities of the regional transmission system. The regional generation zones used in the IRP do not align with more granular potential transmission constraints studied by BPA. Transmission service availability for BPA is determined by each point of receipt and point of delivery combination[2] and relies upon a much more detailed and challenging transmission topology.

Further, existing transmission rights may be bought and sold or may already be controlled by a project developer. PGE has no accurate means to assess the feasibility for third-party developers to acquire transmission rights. Relying solely on transmission ATC available for purchase from BPA at a given point in time could understate the resource delivery feasibility, which would adversely affect the accuracy and relevance of IRP modeling.

Accordingly, PGE did not analyze ATC in evaluating the portfolios in the 2019 IRP. Attempting to do so would mischaracterize much of the complexity of the transmission system. Further, doing so would significantly depart from a process that treats generic resources as proxies for comparison within the IRP, and allows the RFP to deliver specific resource proposals.

[2] BPA also assess issues with the local system in the surrounding area of the point of receipt. This is referred to as a sub-grid analysis.

August 7, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 021
Dated July 24, 2019

Request:

In describing the resources in its preferred portfolio, PGE refers to a quantity of generation in "MWa." Please provide the nameplate capacity for the generation units described in the preferred portfolio.

Response:

PGE objects to this request to the extent that it is vague. Without waiving this objection, PGE responds as follows:

As detailed in Section 7.1 Portfolio Construction as well as Appendix I.6 ROSE-E - PGE's Optimization Tool, ROSE-E allows resource additions in each portfolio to change depending on future market conditions. Only in the Action Plan window (2023-2025) are the resource additions the same across all futures: Section 8.1 – Key Elements of the Preferred Portfolio describes the cumulative customer resource, renewable, and dispatchable capacity additions in the Action Plan window. The preferred portfolio selects, in MWs, the following resources in the Action Plan window:

Preferred Portfolio MW Additions	2023	2024	2025
Pumped Hydro	-	200	-
Gorge Wind	100	-	-
Washington Wind	-	-	180
Montana Wind	262	-	-
6-hour Battery	-	37	-

August 15, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 022
Dated August 1, 2019

Request:

Please provide us with all of the work papers underlying the figures in PGE's IRP, including the source for each data set.

Response:

PGE objects to this request on the grounds that it is overly broad and unduly burdensome. Without waiving these objections, PGE responds as follows.

See Attachments A through S.

Attachment A lists each of the figures in the Executive Summary and Chapters 1 through 8 of the 2019 IRP, notes which attachment contains the information requested for each figure, and lists the relevant sources of information for each data set.

PGE has not provided information for figures that were provided by external consultants, that contain no quantitative data, or contain only illustrative information.

August 30, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 023
Dated August 16, 2019

Request:

With reference to PGE's IRP, Section 4.7.3.1: Please provide all workpapers, studies, analysis and communications related to the two sensitivities for the year 2025.

Response:

PGE objects to this request to the extent that it is overly broad and unduly burdensome. Without waiving these objections, PGE responds as follows:

Please refer to PGE's response to AWEC Data Request No. 003.

August 30, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 024
Dated August 16, 2019

Request:

With reference to PGE's IRP, Section 4.7.3.1: Did PGE evaluate capacity needs associated with LTDA sensitivities for years other than 2025 sensitivities and analysis developed? If so, please provide such evaluations and sensitivities, including all workpapers and studies, and any communications regarding such evaluations and sensitivities. If not, please explain in detail why PGE did not perform such evaluations.

Response:

PGE objects to this request to the extent that it is overly broad and unduly burdensome. Without waiving these objections, PGE responds as follows:

No. The LTDA sensitivity analysis for the 2019 IRP examined the year 2025 only. The year 2025 was selected because in the 2019 IRP, the year 2025 is used for several single-year analyses including ELCC values, integration costs, flexibility values, and capacity adequacy.

August 30, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 025
Dated August 16, 2019

Request:

25. With reference to PGE's IRP, Section 4.7.3.1: Please provide all analyses and projections of the level of long term direct access subscription on PGE's system (*excluding* new load direct access) for each year from 2020 through 2025, including all workpapers and studies and communications related thereto.

Response:

PGE objects to this request to the extent that it is overly broad, unduly burdensome, and mischaracterizes the analysis in Section 4.7.3.1. Without waiving these objections, PGE responds as follows:

As noted in Section 4.7.3.1 of the 2019 IRP, the direct access sensitivities examine the potential impact on the capacity need assessment of the following:

1. Including direct access load based on the enrollment limit of the existing long-term direct access (LTDA) program (300 MWa).
2. Including direct access load based on the combined enrollment limits of the existing LTDA and new load direct access programs (300 MWa + 119 MWa).

These sensitivities are not projections or forecasts of future subscription levels of the existing LTDA or new load direct access programs.

These sensitivities were analyzed for the year 2025 only. Please refer to PGE's response to NIPPC Data Request No. 024.

August 30, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 026
Dated August 16, 2019

Request:

With reference to PGE's IRP, Section 4.7.3.1: Please provide all analyses and projections of the level of *new load* long term direct access subscription for each year from 2020 through 2025, including all workpapers and studies and communications related thereto.

Response:

PGE objects to this request to the extent that is overly broad, unduly burdensome, and requests new analysis. Without waiving these objections, PGE responds as follows:

Please refer to PGE's response to NIPPC Data Request No. 025.

September 11, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 036
Dated August 28, 2019

Request:

For in-system PPA bidders, what interconnection characteristics and status (e.g. executed GIA) does PGE plan to require as a minimum bidding requirement or to receive a preferential bid score in its 150 MWa renewable RFP? Please identify where such requirements and scoring allocations are clearly identified in the IRP.

Response:

PGE objects to this request as requests information outside the scope of this proceeding. The information requested is appropriately addressed in an RFP proceeding. Without waiving these objections PGE responds as follows:

Appendix J of PGE's 2019 IRP includes essential RFP design and scoring elements, including descriptions of PGE's proposed RFP modeling. PGE has not established the referenced interconnection requirements in the 2019 IRP.

September 11, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 042
Dated August 28, 2019

Request:

Please refer to PGE's IRP Appendix J, Section J.2.7. Please identify the source(s) PGE plans to use to estimate or determine how it will adjust prices submitted by bidders for transmission service costs including wheeling, losses, any required ancillary services, and any incremental costs for transmission or distribution system improvements necessary to deliver energy to PGE.

Response:

PGE intends to rely upon tariffed transmission service costs reflected in applicable tariffs of the applicable transmission provider at the time of PGE's evaluation. PGE will also include any transmission upgrade costs assigned to the bidder by the applicable transmission provider as reflected in a bidder's transmission service request study results.

September 11, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 043
Dated August 28, 2019

Request:

Please refer to PGE's IRP Appendix J, Section J.2.7. Please identify the source(s) PGE plans to use to estimate or determine how it will adjust prices submitted by bidders for interconnection costs.

Response:

PGE intends to ensure that the interconnection costs included in the bid are consistent with interconnection facility study results produced by the relevant transmission provider and included within each bid.

September 11, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 044
Dated August 28, 2019

Request:

Please refer to PGE's IRP Appendix J, Section J.2.7. Please identify the source(s) PGE plans to use to estimate or determine how it will adjust prices submitted by bidders for ancillary service costs.

Response:

PGE intends to rely upon ancillary service costs reflected in applicable tariffs or published forecast of ancillary service costs from the applicable transmission provider at the time of PGE's evaluation.

September 11, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 045
Dated August 28, 2019

Request:

Please refer to PGE's IRP Appendix J, Section J.2.7. Please identify the source(s) PGE plans to use to estimate or determine how it will adjust prices submitted by bidders for owner's costs.

Response:

PGE intends to rely upon internally identified owner's cost assumptions to be validated or replaced by a third-party owner's engineer.

September 11, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 046
Dated August 28, 2019

<u>Request:</u>

Please refer to PGE's IRP Appendix J, Section J.2.7. Please identify the source(s) PGE plans to use to estimate or determine how it will adjust prices submitted by bidders for performance assurance costs.

<u>Response:</u>

PGE intends to establish and enforce minimum performance assurance requirements. In addition, PGE retains the right to adjust the bid price to include performance assurance costs should the bidder take exception to the required performance assurances. PGE will rely upon indicative quotes from agents of a qualified institution to provide the necessary performance assurance to a non-investment grade counterparty.

September 11, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 047
Dated August 28, 2019

Request:

Please refer to PGE's IRP Appendix J, Section J.2.7. Please identify the source(s) PGE plans to use to estimate or determine how it will adjust prices submitted by bidders for customer costs associated with the utilization of incremental tax credits.

Response:

PGE intends to only adjust prices to account for tax credit carryforward costs associated with PGE's utilization of incremental tax credits. PGE will rely upon a forecast of PGE's tax credit utilization to determine the price adjustment.

September 11, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 054
Dated August 28, 2019

Request:

Please refer to PGE's IRP Appendix J, Section J.3.2.1 regarding the non-price factor evaluating the likelihood that a project will be placed in service.

a) Please explain why PGE cannot convert the characteristic into a minimum threshold.

b) Please explain how PGE plans to objectively score the project-specific risks or benefits associated with this characteristic.

Response:

a) PGE objects to this request as it requests information outside the scope of this proceeding.

b) PGE objects to this request as it requests information outside the scope of this proceeding.

September 11, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 055
Dated August 28, 2019

Request:

Please refer to PGE's IRP Appendix J, Section J.3.2.2 regarding the non-price factor evaluating the production and delivery of power to PGE.

a) Please explain why PGE cannot convert the characteristic into a minimum threshold.

b) Please explain how PGE plans to objectively score the project-specific risks or benefits associated with this characteristic.

Response:

a) PGE objects to this request as it requests information outside the scope of this proceeding. The information requested is appropriately addressed in an RFP proceeding.

b) PGE objects to this request as it requests information outside the scope of this proceeding. The information requested is appropriately addressed in an RFP proceeding.

September 11, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 056
Dated August 28, 2019

Request:

Please refer to PGE's IRP Appendix J, Section J.3.2.3 regarding the non-price factor evaluating the ability of the project to match PGE's system operating needs.

a) Please explain why PGE cannot convert the characteristic into a minimum threshold.

b) Please explain how PGE plans to objectively score the project-specific risks or benefits associated with this characteristic.

Response:

a) PGE objects to this request as it requests information outside the scope of this proceeding. The information requested is appropriately addressed in an RFP proceeding.
b) PGE objects to this request as it requests information outside the scope of this proceeding. The information requested is appropriately addressed in an RFP proceeding.

September 11, 2019

TO: Irion Sanger
Northwest and Intermountain Power Producers Coalition

FROM: Jay Tinker
Director, Rates and Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 73
PGE Response to NIPPC Data Request No. 057
Dated August 28, 2019

Request:

Please refer to PGE's IRP Appendix J, Section J.3.2.4 regarding the non-price factor evaluating the creditworthiness of the bidder.

a) Please explain why PGE cannot convert the characteristic into a minimum threshold.

b) Please explain how PGE plans to objectively score the project-specific risks or benefits associated with this characteristic.

Response:

a) PGE objects to this request as it requests information outside the scope of this proceeding. The information requested is appropriately addressed in an RFP proceeding.

b) PGE objects to this request as it requests information outside the scope of this proceeding. The information requested is appropriately addressed in an RFP proceeding.

Attachment B

BPA Administrator letter to region re south of Alston

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

EXECUTIVE OFFICE

May 17, 2017

In reply refer to: A-7

To parties interested in the I-5 Corridor Reinforcement Project:

The Bonneville Power Administration has completed an extensive analysis of the need for the I-5 Corridor Reinforcement Project and decided not to build the proposed transmission line. This decision caps an intensive review that included one of the most comprehensive public engagement processes BPA has ever undertaken. Much has changed since BPA proposed the transmission line, and I have concluded that constructing the line would not fulfill our commitment to making the right investment at the right time.

BPA proposed the I-5 Corridor Reinforcement project in 2009 as a solution to preserve reliability, meet existing contract requirements, reduce curtailments, and serve demand on the transmission system – which at the time was growing. More recently, BPA considered the size, local impacts and increasing costs of the proposed project, which prompted us to take a hard look at all of our transmission practices and analytics, including a fresh look at load (electrical demand) forecasts, generation changes and market dynamics.

As a result of this comprehensive review and the inherent difficulties associated with building this line, we are taking a new approach to managing congestion on our transmission grid. My decision today reflects a shift for BPA – from the traditional approach of primarily relying on new construction to meet changing transmission needs, to embracing a more flexible, scalable, and economically and operationally efficient approach to managing our transmission system. We will also increase our reliance on advanced technology, robust regional planning, industry standard commercial practices and coordinated system operations.

Going forward, we will leverage the tools of the modern energy economy to maximize the value of federal assets for our customers and the broader region. Through the transformational efforts described below, we will maximize grid availability, use and reliability to support economic growth along this and other important transmission corridors.

To those who have been with us every step of the way, I would like to acknowledge and thank you for the time you invested in reading our material, attending meetings and providing comments as we took nearly nine years at significant cost to complete a comprehensive review of the project and its potential impacts. This was a difficult decision, compounded by many technically complex and moving parts, and I understand the uncertainty this created for the landowners and homeowners along the route alternatives. Though the process was lengthy, I simply could not risk making a decision of this magnitude without first acquiring the best possible information, and I can say with confidence today that Bonneville is making the best decision for the region.

A summary of our in-depth review

In September 2016 we convened an independent review panel of industry experts to review study assumptions, methodologies, results and assessments supporting the need for the I-5 Corridor Reinforcement Project. The panel concluded that "the proposed 500-kV line could meet the reliability needs…, but that line will add far more capacity than is required for reliability alone." We agreed.

We also observed changes to our regional power system and transmission reliability planning standards. For example, the proposed transmission line would have helped manage the summer congestion impacts of power that flows north to south across the South of Allston flowgate – the portion of the transmission grid this project would have augmented. Contributing to this congestion is power from the coal-fired generators in Centralia, Washington, that are required by state law to close in 2020 and 2025. This should help relieve summer congestion, depending on where replacement generation is sited. Additionally, new national reliability regulations took effect in January 2016. These reliability standards changed the way line limits are calculated. This new standard will increase the potential for other regional utilities to consider infrastructure upgrades or additions that would provide additional transmission capacity and relieve congestion in this corridor.

Further, recent trends indicate that load growth has generally slowed relative to what was assumed in prior studies. However, we are also seeing the potential rapid development of large loads associated with the technology sector that could add hundreds of megawatts of baseload demand in a concentrated geographic area. Meeting the needs of such sudden and unexpected loads is a demanding task, whether through builds, technology or business changes. In this case, where we have decided against building the proposed project, Bonneville and its regional utility partners will need to maximize the use of modern approaches to grid design to meet load growth and economic development objectives.

Moving forward

We will be transforming our approach to adding transmission capacity by making more scalable and flexible investments in the federal transmission system. Focused effort will be given to integrated coordination of operations, transmission planning and commercial processes to support our product portfolio. Bonneville will need to establish a new level of risk tolerance to maximize the use of its transmission assets while meeting customer needs.

We have already put in place or are considering the following transformational approaches:

- Available transmission capacity calculations will be modified to take a more risk-informed profile, potentially enabling greater sales on the existing transmission system.

- In alignment with FERC *pro forma* tariff and industry standards, BPA will review and may modify its commercial transmission products and services.

- New state awareness tools and use of generation redispatch together with increased operational connectivity with the California Independent System Operator will ensure more effective real-time monitoring. The incorporation of real-time data and analysis into the calculation of system limitations may release excess capacity while maintaining reliability. Enhanced visibility and control of loads, resources and flows (including market flows) will allow more accurate, effective and reliable management of the transmission system.

- Non-wires measures to manage generation and loads to reduce peak congestion will launch this summer. We also will look to use cutting-edge grid technologies such as battery storage and flow control devices to proactively manage congestion and further extend operational capacity of the existing system.

- We will work closely with the region's other utilities, regional planning organizations and economic development organizations to convey the economic and operational implications of siting loads and generation resources in different areas. We will incentivize new load centers and resources to locate in areas that will make the best use of existing transmission capacity and minimize costs to them and to the region's electricity consumers.

The decision to not build the I-5 Corridor Reinforcement Project does not mean we and others will not need to build new lines in the future to provide additional transmission capacity in the Northwest. The region inevitably will need to build new lines, as well as rebuild existing, aging lines. But through this decision today, Bonneville is committing to taking a forward-looking approach with its investment decisions, and the region can be certain that BPA will seek first to use efficiencies and build at the smallest scale possible to meet our customers' needs, ensuring Bonneville remains a reliable engine of economic prosperity and environmental sustainability in the Northwest.

Understanding the certainty of business dealings our customers require, I want to reinforce Bonneville's commitment to offering terms and conditions of transmission service that align with FERC's *pro forma* tariff as much as possible; and indeed, we will be moving closer to that paradigm.

Work is already underway to craft solutions and design our way forward. Within a month, we expect to begin discussing these new approaches with our transmission customers and other stakeholders. During these discussions, Transmission Services will explain how we will advance our strategy and provide options for those seeking service across the South of Allston flowgate.

Thank you again for working with us as we take steps toward a more innovative transmission grid, updated business practices and improved regional coordination. This work is indicative of our commitment to working collaboratively with all of our stakeholders to deliver the best value for the region.

Sincerely,

/s/ Elliot E. Mainzer, May 17, 2017

Elliot E. Mainzer
Administrator and Chief Executive Officer