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 FINAL COMMENTS

I. INTRODUCTION

The Northwest and Intermountain Power Producers Coalition ("NIPPC") respectfully submits these Final Comments for consideration by the Oregon Public Utility Commission ("Commission") on Portland General Electric Company's ("PGE") 2019 Integrated Resource Plan ("IRP"). NIPPC filed Opening Comments in this matter on October 11, 2019. Overall, NIPPC is disappointed that it looks like PGE's IRP is setting up a request for proposal ("RFP") with transmission limitations which will result in only PGE's favored resources having an opportunity to win the upcoming RFP. NIPPC made similar warnings in PGE's last IRP and RFP. The Commission did not make the necessary changes to PGE's last RFP to result in meaningful competition; PGE chose a resource in which it had an ownership interest. In addition, PGE has provided very limited information in this IRP in response to the Commission's new RFP rules, which require a utility to include detailed information regarding the upcoming RFP in the IRP. NIPPC is hopeful that this time, PGE does not use a "fast track" process in its upcoming RFP—because if it does, NIPPC believes PGE will put bidders in a worse position than if the Commission had not adopted new rules. This is the case, because bidders will not be provided meaningful information in the IRP, and will have less time to review the RFP once it is filed. NIPPC believes that requiring PGE to provide detailed information and adequate time are fundamental elements of a functional RFP. Finally, NIPPC believes that utility resource procurement efforts should contemplate long-lead time resources.

II. TRANSMISSION COMMENTS

A. Efficient Use of Existing Rights Supplemented with Short Term Firm or Non-Firm Service

With two notable exceptions, PGE has an "all or nothing" approach to transmission in its IRP. Despite early objections from stakeholders, PGE decided to base its entire IRP analysis on the assumption that transmission would be available on BPA's system at BPA's tariff rate. PGE then, which we appreciate, issued its Interim Transmission Addendum. In the Addendum, which is looked upon favorably by both stakeholders and OPUC staff, PGE offers two concessions to calls for increased flexibility in the transmission requirements for a renewable procurement. The first is to allow bidders to bring transmission rights for only 80% of the project's nameplate capacity. The second is to allow bidders to support their bid with conditional firm service from BPA. NIPPC supported these small, incremental steps towards increasing the efficient use of the BPA's transmission grid, but suggested that PGE could do more.

PGE's response to those suggestions, however, was once again to fall back on an "all or nothing" analysis of transmission. PGE makes a compelling case that it cannot rely only on non-firm transmission, that it cannot rely only on short term transmission, and that it cannot always redirect its existing transmission rights. NIPPC agrees.

NIPPC never intended to suggest that PGE should rely only on non-firm transmission, or rely solely on short term transmission, or even that PGE could always redirect its existing transmission portfolio of long term firm point to point ("PTP") transmission rights to a different generator on BPA's system.

But PGE can use redirects to redeploy its transmission rights in some hours between some locations. NIPPC also suggests that "some" level of non-firm and that "some" level of short term firm (beyond 20% of the proposed procurement) could be deployed to the benefit of ratepayers. How much of the 433.6 MW of long term firm transmission service that PGE proposes to acquire (either directly or indirectly) could be deferred would depend on the locations of the resources procured, their generation profile, and how much additional transmission risk is acceptable to the Commission. There is too much near term uncertainty regarding how much transmission load serving entities like PGE will need in the future and how existing transmission rights will be used in the new markets to justify acquiring new transmission rights either directly (reserved by PGE) or indirectly (reserved by independent developers bidding into the request for proposal ("RFP") where the bid price will likely include the cost of any transmission required to support the bid). This is more fully discussed below in Section D related to the regionalization of the energy markets. But in the absence of any analysis of how much curtailment risk is acceptable to PGE (and the Commission), PGE's need for additional transmission, or the transmission curtailment risk associated with the specific resource zones established in PGE's IRP (all of which may change in the near future), NIPPC is unable to make any recommendations beyond asking the Commission to order PGE to perform those analyses. Transmission is so very critical to the viability of a resource that can serve PGE's load; it is fundamental that these analyses be performed in order to inform this process.

B. Deferred Service

In its Reply Comments, PGE notes that NIPPC suggested the Commission require PGE to allow bidders to PGE's deferred transmission rights on BPA's system. But PGE's Reply Comments are then silent on the question of how PGE intends to use these deferred rights.

When a customer requests long-term firm PTP transmission service on BPA's system and BPA accepts the reservation request (because it has transmission capacity available), the customer has the option to extend the date for commencement of service (or defer the start date). The customer has the option to delay the start of service up to five times for as long as one year each time. The cost for an extension of commencement of service is one month of service.

PGE currently has deferred service on four requests totaling 350 MW of transmission service on BPA's system from the Slatt Substation to PGE. Slatt Substation is located outside Arlington, OR and was constructed for the primary purpose of connecting wind generation located in the Columbia River Gorge to BPA's transmission grid. PGE acquired these rights from another transmission customer. One of the requests has already been deferred five times and cannot be deferred again. The other three requests have been deferred four times and could be deferred once more. PGE intends to take service on these requests when they become active (although PGE has - within the limits of the deferral process - the ability to determine when those requests become active).[1] PGE has not shown any intention of activating these rights (or timing the deferral to coincide with its procurement) which precludes bidders from bidding into PGE's renewable resource procurement in reliance on these transmission rights.

Rather, it appears that PGE intends to use these rights itself. And, if that is the case, the effect will be to limit the ability of independent power producers to compete with PGE's benchmark generation in a procurement process, due to the lack of transmission access.[2] A PGE benchmark resource would have a distinct advantage under the terms of the proposed Transmission Addendum which would allow potential bidders to use conditional firm service for 80% of the nameplate of the resource. In the scoring process in the RFP, PGE would be able to bid its own proposed generation using long term firm PTP service on BPA's system; its own projects would not face any scoring discount for bringing transmission rights for only 80% of the project's capacity or a discount for basing its bid on conditional firm service. PGE can essentially guarantee its projects will be selected in the RFP by timing the start of service of these deferred contracts. This unfairness needs to be addressed.

The Commission is well aware that transmission availability is one of the primary factors limiting the options available to PGE's ratepayers in the RFP process. PGE

[1] *See* Attachment A, PGE Response to NIPPC Data Request No. 66. Note that NIPPC originally designated its Data Request No. 66 as confidential, but PGE later confirmed that it contains no confidential information.

[2] PGE may decide to not include a benchmark resource in this RFP. This will not allow competitors access to these transmission capabilities and will effectively limit the pool of potential bidders, while PGE reserves the transmission rights for a future PGE-owned resource.

seems to exacerbate this shortage of transmission by accumulating rights on BPA's system and deferring start dates for reservations. PGE could have released these rights back to BPA for sale to other customers. PGE could have commenced service and only required RFP bids to obtain an interconnection to the Slatt Substation (allowing bidders to use these transmission rights). Instead PGE has continued to defer these transmission reservations which keeps them out of the regional inventory and limits the ability of independent power producers to compete on an equal basis.

This situation cannot be viewed as anything but aiding PGE to benefit PGE's shareholders, not its ratepayers. Ratepayers would benefit if these rights were used to secure the least cost and least risk generation resources. Shareholders will benefit (and ratepayers will be harmed) when PGE sets the conditions of the RFP to ensure that its own projects using these transmission rights prevail in the "competitive" resource procurement process. Even though the proposed Transmission Addendum appears to offer more flexibility to bidders in response to Commission pressure, how PGE uses these deferred transmission rights could well predetermine the outcome in PGE's ratepayers' disfavor.

C. Coal Retirements

PGE has announced the closure of two coal fired generation resources, Boardman and Colstrip. Boardman Coal Plant in the Columbia River Gorge is scheduled to retire in 2020 freeing up 585 MW of long term firm PTP transmission service. PGE's future use of these transmission rights, however, is not addressed in either the IRP or the Interim Transmission Addendum. Surprisingly, PGE does discuss the future of transmission associated with the future retirement of Colstrip 3 and 4. In the case of Colstrip, PGE clearly anticipates deploying its Colstrip transmission rights through the acquisition of a future Montana wind resource. The Boardman transmission rights should be used to ensure that ratepayers have access to the least cost/least risk projects bid into any renewable energy procurement. Otherwise, PGE's ratepayers will be forced to purchase renewable resources from the least cost/least risk bid that has transmission rights. PGE, however, has made no commitments regarding the future deployment of the Boardman transmission rights. Depending upon the location of the renewable generation, the Boardman retirement would free up sufficient transmission rights to provide service for the full quantity of the proposed renewables procurement. NIPPC also hopes that, when PGE begins any procurement of wind resources from Montana, the transmission rights associated with Colstrip will be made available to all bidders, not reserved exclusively to support self-build options submitted by PGE.

D. Regional Markets

In its Reply Comments, PGE responds to suggestions to consider the impact of the Energy Imbalance Market on transmission dispatch. NIPPC agrees that the Western energy market is in a period of transition, e.g., BPA plans to join the Energy Imbalance Market in 2023. The California ISO has begun stakeholder processes to both enhance the types of products traded in the CAISO market (to include capacity products) in the Day Ahead Market Enhancement ("DAME") process as well as expand the granularity of the EIM market into the Day Ahead time frame (Enhanced Day Ahead Market or EDAM). NIPPC agrees with PGE that it is still too early - and there is too much uncertainty around the final form of those market enhancements - to expect PGE to provide any detailed analysis of the benefits that will flow from those market reforms, especially with regard to transmission.

That uncertainty, however, is yet another reason for the Commission to view the proposed Transmission Addendum with concern. At the very time that the Western Energy market will be entering the unknown, PGE would have its ratepayers commit to almost 500 MW of new long term firm PTP contracts (as PGE notes the cost of conditional firm service is the same). While transmission customers may purchase long-term firm transmission service for as little as one year, in order to secure rollover rights (necessary to ensure that the transmission provider will not terminate service in the future) transmission customers must agree to service for five years or more. In its Transmission Service Expansion Planning Process, however, BPA requires customers to commit to service for a term long enough to ensure that the customer seeking the transmission upgrades will pay its full share of the cost of the upgrades. Given the uncertainty associated with how transmission will be treated in these rapidly evolving markets, there is too much uncertainty to require PGE ratepayers to make commitments to new long-term firm PTP contracts (or conditional firm contracts) when PGE already has long-term firm transmission rights sufficient to support all of the proposed renewables procurement. These long-term transmission rights are the result of transmission rights that are freed up following the Boardman retirement and PGE's deferred transmission rights.

If the coming market reforms meet their promise, the market dispatch mechanism may eliminate the need for long-term transmission (contract) rights associated with specific generation in favor of dispatching the most efficient mix of generation to meet load regardless of who administers the resource dispatch and how the rights to transmission capability is optimized . Accordingly, it would be prudent to delay requiring PGE ratepayers to take on the financial commitment associated with new long-term transmission rights and instead rely on PGE's existing transmission service rights, supplemented as necessary with incremental purchases of short term firm and/or non-firm transmission service.

E. Resource Diversity

In its Reply Comments, PGE suggests:

> The RFP analysis will also capture the impact of the transmission services associated with each resource, as described in the Interim Transmission Solution. If a bid contains two or more diverse resources which share one or more legs of transmission service to PGE, the RFP analysis will account for both the diversity benefits of the resources and the limitations or benefits of the transmission service associated with the combined resources. The assessment of the benefits provided will depend on the specific characteristics of the generating resources and transmission service associated with the bid. For example, complementary facilities like wind and solar may not require additive transmission service or a facility paired with energy storage can reduce its transmission need.[3]

NIPPC, however, is unable to locate any discussion in the Interim Transmission Solution regarding how an RFP analysis will treat bids consisting of diverse resources. This is another example of NIPPC's concerns with respect to the need for additional detail in the Interim Transmission Solution which will better inform how the RFP will be conducted and scored. The lack of detail is unfortunate because NIPPC could have supported this concept if it had appeared in the Interim Transmission Solution. NIPPC would also have suggested that the diversity benefits maximizing transmission should not

[3] PGE Reply Comments at 76-77.

be limited to single bids. Rather the RFP should deploy the same analysis to all potential bids; not just those that feature two diverse resources as part of the same bid. For example, there does not appear to be a compelling reason that the transmission requirements of two separate bids consisting of one bid of 100 MW of Gorge Wind and a separate bid of 50 MW of Gorge solar should be scored differently than the transmission requirements of a single bid combining the two? NIPPC believes that PGE should be taking advantage of all opportunities to use the diversity of renewable generation output from different types of generating resources and from resources located in different zones, not just those that happen to be bundled into a single bid.

PGE argues that the details of the procurement should only be disclosed following Commission acknowledgment of the IRP. PGE, however, appears to be willing to release favorable details to the Commission which NIPPC believes is in hopes of obtaining acknowledgement. In NIPPC's opinion, PGE's Reply Comments are not the appropriate place to announce details of the proposed procurement process described in the Interim Transmission Solution. Instead, if PGE wants to obtain acknowledgement of its transmission plan or "fast track" treatment in its RFP, NIPPC believes that the Commission, Staff and all stakeholders should have a more detailed understanding of the proposed RFP process including scoring metrics and any new contract language as a precursor to acknowledgment. NIPPC is less concerned by the early release of favorable details, and more concerned about the details that will lead to a fair procurement process.

III. DIRECT ACCESS COMMENTS

NIPPC reiterates its recommendation that the Commission reject PGE's analysis with respect to the intertwined issues as to whether direct access suppliers should be subject to a reliability requirement, how such requirement should be measured, and who should be permitted to supply resource adequacy services (henceforth "Direct Access Resource Adequacy Issues") as well as PGE's proposal that it be allowed to acquire capacity and be the sole provider of resource adequacy in support of the direct access market. These issues are currently before the Commission in other dockets, and the major policy changes PGE is seeking cannot be effectively considered in the context of this IRP docket without a fulsome consideration of facts and law not before the Commission here. PGE's proposal is also fundamentally at odds with Oregon law.

A. Issues Related to Appropriate Resource Adequacy Requirements For Direct Access Are Before The Commission in Existing Dockets

As PGE recognized in its Reply Comments, Direct Access Resource Adequacy Issues are already before the Commission in other dockets.[4] In particular, the same day PGE filed its Reply Comments in this docket, PGE, Commission Staff and a variety of interested parties filed detailed opening briefs addressing Direct Access Resource Adequacy Issues, with reply briefing further addressing the topic filed November 26, 2019, in Docket UE 358. Also, on December 12, the Commission held its first workshop in the "generic" direct access proceeding docketed as UM 2024. The stipulated issues list for that docket (attached hereto as Attachment B) expressly addresses how load serving entities should plan to ensure resource adequacy within the direct access framework. Docket UM 2024 is the correct docket to consider these issues, and the Commission should decline from addressing them further herein.

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[4] PGE Reply Comments at 56-58

B. Supply of Resource Adequacy is a Competitive Product by Oregon Law

In its Reply Comments, PGE states its belief that "PGE believes that PGE is the best entity to engage in the capacity procurement for direct access loads, given PGE's role and responsibility to be the reliability provider within the balancing authority." PGE goes on to ask the Commission for authority to plan for and procure such capacity.[5]

PGE is wrong. To the extent the Commission determines it to be appropriate to impose resource adequacy requirements on the competitive market, the participants in that market are the best entities to engage in such procurement. But more to the point, PGE's proposal that it be allowed to act as the sole provider of this service is fundamentally at odds with Oregon law. Oregon's direct access law allows eligible customers to '"opt out 'of purchasing electricity" from their distribution utility and "instead, purchase electricity directly from a certified electricity service supplier, using [their distribution utility]'s distribution system."[6] The law expressly defines direct access to include "the ability of a retail electricity consumer to purchase electricity and certain ancillary services, as determined by the commission for an electric company or the governing body of a consumer-owned utility, directly from an entity other than the distribution utility."[7] It further defines "electricity" to mean "electric energy, measured in kilowatt-hours, or electric capacity, measured in kilowatts, or both."[8] In other words, the law requires that non-residential customers be allowed to purchase "electric energy . .

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5 PGE Reply Comments at 56-57.
6 *Calpine Energy Solutions, LLC v. PUC*, 298 Or App 143 at 147 (2019).
7 ORS 757.600(6).
8 ORS 757.600(14).

. or electric capacity . . . or both" from the market through direct access.[9] This is even true in emergency situations: ORS 757.622 requires that the Commission:

> establish terms and conditions for providing default electricity service for nonresidential electricity consumers in an emergency. The commission also shall establish reasonable terms and conditions for providing default service to a nonresidential electricity consumer in circumstances when the consumer is receiving electricity services through direct access and elects instead to receive such services through the default service. The terms and conditions for default service established by the commission ***shall provide for viable competition among electricity service suppliers***.[10]

PGE's proposal that it be the sole supplier of capacity to support resource adequacy for direct access is fundamentally at odds with Oregon law, and must be rejected. Even in emergency circumstances, direct access customers are entitled to access the competitive market, and cannot be forced to purchase resource adequacy from the utility.

IV. RFP COMMENTS

NIPPC remains concerned that PGE's RFP process will result in bidders and stakeholders having access to less information then they would have without the Commission's new rules and less than what the new rules contemplate. As noted in the Administrative Law Judge Memorandum issued December 11, 2019, NIPPC agrees that the Commission's task in this first implementation of the new competitive bidding rules is to determine how much RFP detail the utility must include in its IRP, if any, and how much detail is sufficient to skip the step in the independent evaluator ("IE") selection docket where the utility would otherwise be required to file a proposal containing the

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9 *Id.*

10 ORS 757.622 (emphasis added).

RFP design, scoring methodology, and associated modelling. In the Commission's order adopting the new competitive bidding rules, the Commission notes that:

> Clearly expressing the system needs associated with a resource acquisition is an important objective reflected in these rules. Presenting those needs in detail and the scoring associated with an acquisition in the IRP will allow notice to prospective bidders and the opportunity for stakeholders to understand and, where necessary, for utilities and the Commission to improve the acquisition process.[11]

As fully detailed in NIPPC's Opening Comments, NIPPC does not believe that PGE has provided sufficient detail in its IRP or sufficient detail in order to take the "fast track" in the IE selection docket, and believes that in particular, PGE's non-price scoring criteria is not sufficiently detailed to provide any notice to prospective bidders or stakeholders to understand and improve the process.

A. Appendix J Provides Little Additional Information Than Past IRPs

Here, PGE provides little additional information in identifying the system need and resource characteristics than it has in past IRPs. In PGE's 2016 IRP, it identified a need to procure 175 MWa of RPS-compliant renewable resources that would come online by 2018.[12] In this IRP, PGE identifies a need to procure 150 MWa of RPS-compliant renewable resources that will come online by 2023.[13] In both cases, the IRP simply tells us that the "need" PGE identifies is for an RPS-compliant renewable resource. As noted above, the Commission contemplated that the needs would be express "in detail" and that the "scoring associated with the acquisition" would be in the IRP, in order to provide

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11 *In re Rulemaking Re: Allowances for Diverse Ownership of Renewable Energy Resources*, Docket No. AR 600, Order No. 18-324 at 8 (Aug. 30, 2018).

12 PGE 2016 IRP at 308.

13 PGE 2019 IRP at 216.

notice to potential bidders and stakeholders, but where little additional detail is provided, it is difficult to see how the new rules have improved the process.

The competitive bidding rules require that the RFP non-price score primarily relate to "resource characteristics" identified in the last acknowledged IRP Action Plan or IRP Update,[14] yet PGE's IRP provides no transparency into what other characteristics PGE needs while at the same time telling us that the RFP score will be affected by other resource characteristics. For example, PGE will consider curtailment obligations, engineering reliability characteristics, resource fuel availability confidence, and whether PGE is able to use the project as a credit for its remedial action scheme obligations in evaluation of the RFP bids.[15] Notably absent from PGE's IRP Action Plan, however, is any identification of what it "needs" in relation to these resource characteristics, thus, should PGE consider such characteristics in its RFP non-price score, it will be difficult to show how the non-price score "primarily relate[s] to resource characteristics identified in the . . . most recent acknowledged IRP Action Plan" as required by rule. Therefore, in addition to providing that it needs an RPS-compliant resource by 2023, PGE should provide more information regarding what other resource characteristics it needs that will affect the non-price score.

B. A Reasonable Market Participant Already Knows the Majority of the Information Provided in PGE's Appendix J

PGE's Appendix J essentially lists generic factors and considerations that any reasonable market participant already knows. It will come as no surprise to any potential

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[14] OAR 860-089-0400(2)(b).
[15] PGE 2019 IRP, Appendix J at 371 § J.3.2.2.

bidder that their bid may be affected by the items PGE discusses in Appendix J, but PGE does not provide any additional information regarding how those characteristics will affect the score. PGE notes that there will be a 60/40 split of price/non-price scoring criteria, but provides no other detail regarding the scoring associated with the acquisition, other than a list of potential factors that may impact it.

PGE should provide additional detail on how each of the proposed factors will affect the score. This is not to say that PGE's IRP must include all information necessary for a final RFP filing, but it should provide sufficient information to provide notice to prospective bidders and the opportunity for stakeholders to understand and, where necessary, for utilities and the Commission to improve the acquisition process. What PGE has provided is a list of factors that a market participant already knows *may* affect its score, but is not adequate to understand *how* those factors will affect the score.

In addition, and as articulated in NIPPC's Opening Comments, many of the non-price factors may be converted to minimum bid requirements, which could substantially improve the transparency behind how such factors will affect a potential bidder's eligibility and likelihood of success. A key driver behind the revised rules is to let potential bidders know earlier in the process whether they will even be competitive in the RFP. Without knowing which non-price factors are actually minimum bid requirements, a potential bidder will have no additional knowledge about whether it even has a chance at success.

C. PGE Has Not Provided Sufficient RFP Detail to Relieve it of the Obligation to File an RFP Proposal in the IE Selection Docket

PGE's Appendix J appears to be an attempt to include enough of the RFP design, scoring methodology, and associated modeling within the IRP sufficient to relieve PGE of the obligation to later file the RFP proposal in the IE selection docket contemplated by OAR 860-089-0250(2)(a). PGE has not provided sufficient detail to relieve it of that obligation.

Specifically, prior to preparing a draft RFP, a utility must "develop and file for approval in the electric company's IE selection docket, a proposal for scoring and any associated modeling."[16] The company can skip this step if it "intends to use an RFP whose design, scoring methodology, and associated modeling process were included as part of the Commission-acknowledged IRP."[17] As discussed above and in NIPPC's Opening Comments, PGE's IRP provides little design, scoring information, or the associated modeling. The information provided is essentially the same as what PGE has provided in the past, with the addition that PGE has provided a list of factors that may affect the score (which most market participants already know) and does not provide specifics regarding how the proposed factors will affect a bidder's score.

Even if PGE does not intend for Appendix J to relieve it of its obligation to file an RFP proposal in the IE selection docket, the IRP still does not provide information required by the new rules. Specifically, when PGE ultimately issues its draft RFP, that draft RFP "must reflect any RFP elements, scoring methodology, and associated

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16 OAR 860-089-0250(2)(a).
17 *Id.*

modeling described in the Commission-acknowledged IRP."[18] The RFP cannot reflect elements, scoring methodologies, and modeling described in the IRP if the IRP does not contain that information. Therefore, this information should be provided now rather than in the draft RFP.

D. The Commission Should Avoid an Outcome that Would Make the Competitive Bidding Process Worse Off Than it Was Before the New Rules

NIPPC believed that the Commission's new competitive bidding rules would improve the RFP process by requiring that the utilities provide more information earlier in the process. What NIPPC hopes to avoid, is a situation where the utility provides very limited information in its IRP and is then permitted to skip the step detailed in OAR 860-089-0250(2)(a) where it would normally develop and file an RFP proposal in the IE selection docket including the design, scoring methodology, and associated modeling.

Therefore, when the Commission acknowledges PGE's IRP, it should indicate whether it thinks PGE has provided sufficient information to allow it to skip this step in the IE selection docket.

E. Utility Resource Procurement Efforts Should Contemplate Resources with a Long-Lead Time

In response to the questions detailed in the Administrative Law Judge Memorandum issued December 11, 2019 regarding resources with long-lead times, NIPPC responds that it believes it is important for the Commission to recognize such resources in a manner which to allows the utilities some flexibility to acquire these types of resources. The Commission should acknowledge when a utility has a need that may be

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[18] OAR 860-089-0250(2).

filled with such a long-lead time resource and let the utility pursue such a resource through either an RFP that contemplates long-lead times, or through an appropriate RFP waiver, to the extent such a resource qualifies. NIPPC recommends that the Commission clarify and confirm that a utility plan to acquire a long-lead time resource satisfies the competitive bidding rule exception to the rules when the utility identifies an "alternative acquisition method [that] was proposed by the electric company in the IRP and explicitly acknowledged by the Commission."[19]

V. CONCLUSION

For the reasons articulated above and in NIPPC's Opening Comments, NIPPC recommends that the Commission acknowledge the IRP, subject to the exceptions listed above.

Dated this 17th day of December 2019.

Respectfully submitted,

Sanger Law, PC

Irion A. Sanger
Marie P. Barlow
Sanger Law, PC
1041 SE 58th Place
Portland, OR 97215
Telephone: 503-756-7533
Fax: 503-334-2235
irion@sanger-law.com

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19 OAR 860-089-0100(3)(c).

Blue Planet Energy Law, LLC

/s/ *Carl M. Fink*
Carl M. Fink
Blue Planet Energy Law
628 SW Chestnut St.
Portland, OR 97210
Telephone: 503-819-4188
cmfink@Blueplanetlaw.com

Attorneys for the Northwest and
Intermountain Power Producers Coalition

/s/ *Henry Tilghman*
Henry Tilghman
Tilghman Associates
1816 NE 53rd Ave.
Portland, OR 97213
Telephone: 503-702-3254
hrt@tilghmanassociates.com

Consultant for the Northwest and
Intermountain Power Producers Coalition

Attachment A

PGE Response to NIPPC Data Request No. 66

October 1, 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. 066 CONF
Dated September 17, 2019

Request:

In PGE's Response to NIPPC Data Request No. 010 Attachment A_Confidential, [confidential] PGE indicates that four transmission service requests on BPA's system for long term point to point service from Slatt to PGE (totaling 350 MW) are "Deferred Rights-Slatt".

a. Please explain what "deferred rights" are.
b. Are these transmission service requests currently in deferral status?
c. How many times has the start date of these transmission requests been deferred?
d. Can these transmission requests be deferred beyond the "start date/renewal date" identified in Attachment A?
e. How does PGE intend to deploy these transmission service requests for the benefit of ratepayers?
f. Are these transmission service rights currently associated with delivery of any specific generation asset to PGE's service territory?
g. Why is PGE's Interim Transmission Proposal silent on these transmission service requests?
h. Could these transmission service requests be deployed (in whole or in part) to meet the transmission requirements associated with the generation assets described in either the preferred portfolio in the IRP or any renewable resources procured consistent with the Interim Transmission Proposal?
i. Will PGE make these transmission rights available to bidders in an RFP for renewable resources? If not, why not? [end confidential]

Response:

a. Deferred rights are when a transmission customer has postponed the commencement of service (start date).

b. Yes, these transmission service requests (TSR) are in deferral status.

c. The following summarizes by TSR the number of times the service commencement date has been postponed:

   - 88602747 – 5 times
   - 88100819 – 4 times
   - 88100833 – 4 times
   - 87902862 – 4 times

d. Yes, as noted part c of this response, three of the TSRs have been deferred four times; therefore those TSRs have one remaining deferral request each.

e. PGE objects to this request as it seeks information outside the scope of this proceeding. Without waiving this objection, PGE responds as follows:

   These deferred transmission rights were acquired from a third-party and none of the costs associated with these rights have been included in PGE's customer rates. PGE's current intent is to use these transmission rights when they become active.

f. No, given that these TSRs are in deferral status, the scheduling rights are currently not available for use to support the delivery of generation to PGE's service territory.

g. PGE's 2019 IRP Transmission Addendum details PGE's proposed provisional transmission program and associated RFP transmission requirements, which is not related to or impacted by deferred transmission rights. PGE's Addendum endeavors to identify a broadly applicable and fair transmission solution for additional renewable resources that manages deliverability risks for PGE and its customers. Use of PGE's existing transmission rights does not accomplish these aims.

h. See PGE's response to NIPPC Data Request Nos. 16, 19, and 64 addressing transmission and generic resources used in the IRP. PGE cannot speculate on renewable resources procured through an RFP implementing the Interim Transmission Proposal. See PGE's response to subpart g of this request.

i. No. Please refer to PGE's response to parts g and h of this request.

Attachment B

UM 2024 Stipulated Issues List

ELLEN F. ROSENBLUM
Attorney General

FREDERICK M. BOSS
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

December 3, 2019

***via* E-mail**

Public Utility Commission of Oregon
Attn: Filing Center
201 High Street SE, Suite 100
Salem, OR 97308-1088
PUC.FilingCenter@state.or.us

Re: UM 2024 – Stipulated Issues List

On November 14, 2019, a Notice of Commission Workshop and Agenda was issued in the above-referenced docket, which contains a copy of the proposed issues list that Oregon Public Utility Commission Staff (Staff) circulated to the parties to this proceeding ahead of the October 15, 2019 scoping workshop. At the scoping workshop, participating parties discussed Staff's draft issues list and made suggestions for its improvement. At the conclusion of the workshop, the parties agreed to a draft issues list in principle, that was subsequently circulated and subject to edit by the participating parties in this proceeding.

Given the additional discussion and changes to the issues list made as a result of the scoping workshop, the parties provide the attached stipulated issues list for Commission review and consideration prior to the December 12, 2019 Commission Workshop. The attached issues list represents the stipulated issues list agreed to by the Alliance of Western Energy Consumers (AWEC), Oregon Citizens' Utility Board (CUB), Northwest and Intermountain Power Producers Coalition (NIPPC), Northwest Power and Conservation Council, PacifiCorp, Portland General Electric (PGE), Staff, and Walmart, Inc. Staff was unable to confirm with Calpine Solutions (Calpine) as of the date of this filing, but notes that Calpine participated in the workshop and provided edits to Staff's draft issues list.

Sincerely,

Shawn Riemcke, for

Sommer Moser
Assistant Attorney General
Business Activities Section

Enclosure
ST7:pjr/#9970778

UM 2024 Scoping Docket and Proposed Issues List

1. What are the potential benefits and potential costs to customers from long-term direct access participation?
    a. How can long-term direct access programs be structured to maximize these potential benefits?
    b. How can long-term direct access programs be structured to minimize or eliminate these potential costs?
2. What cost shifts occur when load departs a utility?
    a. What constitutes "unwarranted" cost-shifting?
        i. Are PGE's and PacifiCorp's current long-term direct access programs structured in a way that avoids unwarranted cost-shifting? Topics may include:
            - Transition Adjustments and the potential for Capacity Credits or Capacity Charges
            - Consumer Opt-out Charge
            - Resource Intermittency
            - Freed up RECs
            - Legislative mandates (state and federal) and bypassability of costs
            - Load growth
            - Return-to-cost-of-service restrictions
            - Resource Adequacy
        ii. If not, how should these programs be structured to avoid unwarranted cost- shifting?
3. What limits, if any, should be placed on the ability of a customer to participate in a long-term direct access program? Including:
    a. Caps
    b. Notice Requirements
        i. Election Windows
        ii. Return Notice
        iii. Energization Notice/Timing
    c. Customer Size Requirements
4. How should load serving entities plan in the short and long-term for direct access and all jurisdictional load to ensure resource adequacy?
5. Are current rules, regulations, and other programs recognizing the current state of wholesale power markets while preserving and protecting those markets? Or should the Commission take steps to promote an organized wholesale market structure?
6. How are other states handling customer choice and access to wholesale markets for different customer classes? Along with previously listed issues, topics may include:
    - Provider of last resort obligations

- Deceptive marketing practices, consumer protection
- Price disclosure
- Data disclosure
- General enforcement authority
- Pricing of departing load
- Market design and alignment with customer choice
- Oversight, compliance, and reliability responsibilities
- Capacity and reliability

a. What has worked well, what hasn't?

b. How can these findings be applied to Oregon, including consideration of the fact that Oregon's direct access market is limited to non-residential customers?