BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 66

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY 2016 Integrated Resource Plan.	)))))))	**REDACTED NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION'S FINAL COMMENTS**

I. INTRODUCTION

Northwest and Intermountain Power Producers Coalition ("NIPPC")[1] respectfully submits these Final Comments for consideration by the Oregon Public Utility Commission ("Commission") on Portland General Electric Company's ("PGE" or the "Company") 2016 Integrated Resource Plan ("IRP"). NIPPC supports PGE's renewable resource need in 2018, and believes that it is reasonable for PGE to issue a renewable request for proposal ("RFP") to capture 100% of the benefits of the production tax credit ("PTC"). However, PGE's late filed benchmark wind resource has not been reviewed or analyzed, and should not be acknowledged.

The Commission should also decline to acknowledge PGE's: 1) proposed capacity resource and preference for owned generation; and 2) transmission plan (or lack thereof). Instead of acknowledging the Company's vague plans to own new Carty 2 and 3 capacity

[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, transmission companies and commercial and industrial customers. NIPPC's current member list can be found at http://nippc.org/about/members/.

resources, the Commission should recognize that PGE has a capacity need that is best served with short to medium term power purchase agreements ("PPAs"), and require PGE to conduct additional analysis before issuing a capacity RFP in 2021. To be clear, PGE has a capacity need, but PGE has failed to analyze the various costs, risks, and benefits of different types of capacity resources. Given that this need does not materialize until 2021, and there are numerous opportunities to acquire short and medium term capacity in the market, there is sufficient time to complete a true analysis of PGE's capacity resource options before the next RFP is issued.

Regarding transmission, NIPPC has two related concerns. First, the Commission should direct PGE to conduct a transparent analysis of converting its point to point service ("PTP") to network transmission service ("NITS") on Bonneville Power Administration's ("BPA") system. Such a change could result in significant savings for ratepayers, especially as PGE increases the amount of renewable resources on its system. The long-term risk and bias against non-utility generation associated with PGE's current reliance upon BPA PTP transmission justifies additional analysis. PGE is not treating its transmission system as belonging to ratepayers, but is instead relying upon an approach that could lead to PGE selecting overall more expensive utility owned generation. Second, PGE is reserving significant amounts of PTP transmission for future use by Company-owned generation, which may make it difficult, if not impossible, for certain independent power producer ("IPP") generators to sell power to PGE in an RFP. Essentially, PGE may be using ratepayer funds to secure transmission assets with the practical impact of ensuring that its own riskier and costlier generation wins the next RFP. Whether PGE ultimately relies upon PTP or NITS, PGE's transmission assets should be utilized for the sole benefit of ratepayers, regardless of who ultimately owns the generation resources used to serve consumers.

II. COMMENTS

A. PGE Has Demonstrated a Near-Term Renewable Resource Need

NIPPC sees merit in the Company securing additional renewable capacity on a timely basis. This is particularly true with wind power given the declining financial value of the PTC. In other cases, NIPPC raised concerns regarding PGE's and PacifiCorp's claims that early action to acquire renewable resources was needed due to the expiration of the PTC. NIPPC, however, has always stated that action would be justified at some point. Now that time has passed and we are closer to the PTC's expiration, it is warranted to act to take full advantage of the PTC.

NIPPC is unconvinced by the Company's expressed interest in a benchmark wind power resource described in Section 2.8 of its Reply Comments. Among the considerable factors in evaluating wind power investments, over commitment to one resource area is a danger. The Company has fallen woefully short in making the case for why a benchmark wind power resource is needed for the IRP or subsequent RFP. The Commission should not acknowledge any specific benchmark resource, but instead acknowledge PGE's overall renewable resource need, including the 2018 acquisition date.

B. PGE Has Demonstrated a Mid-Term Capacity Need, but Has Failed to Provide Sufficient Information Regarding the Costs, Benefits, and Risks Associated with Different Types of Capacity Resources

1. PGE Has a Capacity Need that, at this Time, Can Be Met with Near and Medium Term Contracted Resources

With its revisions to its IRP, PGE demonstrates that it appreciates the value of securing capacity resources from the market. The Wells Hydro PPA is as sensible as it is predictable given the highly attractive characteristics of hydropower in a utility resource portfolio. PGE's IRP should count on PGE taking similar reasonable actions.

NIPPC has previously noted and continues to insist that the Company define with far greater precision the operational features it seeks in adding what it describes as dispatchable capacity and peak capacity. NIPPC has not disputed the appealing characteristics of thermal generation for the Company's resource portfolio. At this point in time, gas-fired generation, biomass-fired generation, or pumped storage should be considered as preferred options to meet the Company's high-level and generic stated capacity requirements. Thermal generation and pumped storage can complement hydro resources and back-fill intermittent renewables' increasing presence in PGE's resource base.

PGE is aware that the market currently offers ample operating and permitted (green field) thermal capacity, although its commentary regarding bi-lateral transactions in Section 2.6 of its Reply Comments is oblique. Several thousand megawatts ("MW") of Northwest-based non-utility owned thermal assets are available to meet any and all of the capacity requirements the Company could conceivably need. These currently operating and permitted gas-fired generators are dispatchable, highly efficient, and capable of meeting peak demand, integrating wind and solar while supplying the Company with the ancillary services it may require.

NIPPC agrees with the Citizens' Utility Board of Oregon and others that now is the time to "rent" (contract with) thermal resources rather than encumber ratepayers with new, costly and risk-laden utility owned generation. PGE's assertion that it is unable to contract for thermal power for short durations does not accurately reflect the capabilities of the market. The fact that ample dispatchable thermal capacity is available for contract – for either short or long durations – should not be lost on the Company or the Commission.

NIPPC expects to see much greater specificity from the Company with respect to its capacity requirements upon release of its RFPs, but the Commission should require additional analysis now before the expedited RFP process begins. And while PGE may argue that its description of its capacity needs are satisfactory for the IRP, a point NIPPC disputes, the Company should not be permitted to hide behind acknowledgement of a vague Action Plan when it files its RFPs for the Commission's review.

2. PGE Conceded that Flexible Capacity Resources Have Meaningful Differences, Yet All 23 IRP Portfolios Rely Upon a "Generic" Flexible Capacity Resource

NIPPC pointed out that PGE's analysis found no meaningful difference between flexible capacity resources, and that PGE's IRP relies upon the same resource type as a generic capacity resource in all 23 of its IRP scenarios. PGE has not disputed NIPPC's concerns. Instead, PGE claims "there is no clear industry standard methodology for characterizing flexibility needs"[2] and notes that it "recognizes that incremental improvements to the evaluation" are important.[3] Ultimately PGE failed to adequately evaluate how different flexible resource options meet its capacity need, which results in the IRP not providing the proper foundation for subsequent RFPs, and places potential bidders at a disadvantage. Thus, NIPPC urges the Commission not to acknowledge PGE's capacity resource acquisition without additional study. As PGE is not

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2 PGE Reply Comments at 58.

3 Id. at 59 (PGE "recognizes that incremental improvements to the evaluation will continue to be important in future IRPs, especially as PGE attempts to more fully integrate flexibility considerations into portfolio evaluation").

planning to acquire a capacity resource until 2021, there is ample time to require PGE to conduct the proper analysis.

The flexibility of a dispatchable resource cannot be reduced to a single index or ordinal ranking. Flexibility is defined by many operational characteristics, such as upward and downward ramping capability, minimum generation levels, start-up and shut-down times, minimum and maximum run time, cycling limitations, etc. These important attributes vary across resource technologies and even within resource technologies, and strategic engineering decisions made during project development can affect the amount and value of flexibility attributes of any given resource. Furthermore, once a project is built and integrated into a resource portfolio, fuel and operating costs can be significantly affected when the resource is deployed. The existing utility resource portfolio into which a new capacity resource is integrated also impacts the relative value of different flexibility characteristics. This is why a flexible capacity analysis performed by a third party like E3 is critically important to the IRP. But to be useful, the information developed in the flexible capacity analysis must be incorporated in the IRP Portfolio analysis, and communicated to the parties and the Commission.

As PGE's resource portfolio expands to integrate new non-dispatchable renewable resources, the importance of capacity resource flexibility increases as does the relative value of different resource attributes. Some of these flexibility attributes can be valued on a stand-alone basis, while others need to be modeled in a resource portfolio to capture the actual resource costs and ancillary service values that result when the resource is integrated into a larger portfolio of resources.

NIPPC criticized PGE's flexibility analysis using REFLEX because, according to PGE, the differences between resources studied were not of sufficient importance to warrant testing different flexible capacity resources in the IRP portfolio analysis that used the AURORA model. Instead, PGE defaulted to a single "generic" flexible capacity resource for defining all IRP portfolios studied in AURORA. NIPPC offered an example of how important differences in capacity resources could occur, and demonstrated how PGE's generic capacity resource would perform if dispatched like PGE's existing RICE technology used for Port Westward 2. NIPPC showed that PGE's generic capacity resource could be expected to emit 80,000 more tons (45%) of CO_2, and consume almost $5 million more in fuel annually, than PGE's Port Westward 2.

PGE countered that a key finding of the REFLEX study was that under a 25% renewable portfolio standard in 2021, the system required at least 400 MW of additional dispatchable resources to ensure that potential upward flexibility imbalance experienced in real-time did not increase over the 2015 baseline portfolio. NIPPC appreciates this finding, but believes that much more analysis is necessary to understand which type of flexible capacity resources will be least cost and least risk.

Based on representations by PGE and E3 in IRP Public Meeting #3 on August 13, 2015, NIPPC fully expected more information to be forthcoming from PGE on the results of their flexible capacity analysis. In that meeting, E3 made a presentation and progress report on their flexible capacity analysis being performed for PGE, and reported that they had yet to complete the final task which was to "*Simulate Dispatch and Quantify Curtailment with Candidate Resources"*.[4]

The final report from E3 should have provided the expanded information and REFLEX modeling results that would be important for a quality IRP, and for informing the evaluation (scoring) criteria for future resource RFP's. NIPPC submitted a data request to PGE requesting a copy of the final report from E3 reflecting completion of the above task.[5] PGE objected to the relevancy of that request, but responded to NIPPC's request as follows:

> Attachment 111-A contains the final presentation provided to PGE from E3 regarding REFLEX modeling exercises of the PGE system. In addition to the REFLEX analysis described in Section 5.3 of the 2016 IRP, this deliverable included material that was not utilized in the 2016 IRP and material that was preliminary and not confirmed by PGE. Pages containing material not utilized in the 2016 IRP have been redacted. Attachment 111-A is protected information subject to Protective Order 16-048.[6]

Attachment 111-A is dated [redacted]

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4 2016 IRP Public Meeting #3, PGE Presentation at 85 (Aug. 13, 2015), available at https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning.

5 See Attachment A at 1 (PGE's Response to NIPPC DR No. 111 (Apr. 25, 2017)).

6 Id. at 2.

[redacted] Thus, PGE's response confirms that it has not adequately analyzed the flexible capacity resource options available.

PGE's response indicates that it did not perform (or has not provided) all the REFLEX analysis needed to support its conclusions about the different flexible capacity technology alternatives to the stakeholders. If either PGE or E3 has done any additional modeling or verification, then they should present that information to the Commission for review. If neither PGE nor E3 has done the additional verification and modeling called for in PGE's third public meeting, then the Commission should order PGE to provide this analysis so that the Commission can determine the costs and benefits of different types of capacity resources.

3. PGE's Analysis Relies Upon Incorrect Data Inputs for Heat Rate Curve and Turnaround Time

NIPPC also discovered that PGE used incorrect data assumptions in its REFLEX modeling, which distorted the operating characteristics of certain flexible capacity resources. More specifically, PGE's heat rate curve and turnaround time assumptions were not consistent with the data PGE uses to represent its own resources in the REFLEX model. This is important because it calls into question PGE's conclusions with respect to the different flexible capacity resources and ultimately PGE's determination to use one generic capacity resource type in all its IRP scenarios.

PGE argues that it merely relied upon data provided by Black &Veatch to populate the parameters for new generic resources.[7] PGE also claims that NIPPC's statements about heat rate

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[7] PGE's Reply Comments at 60.

assumptions are incorrect and notes that PGE was not able to verify the heat rate curves supplied by NIPPC.

Simply put, PGE incorrectly used the heat rate data provided by Black & Veatch. More specifically, [redacted] NIPPC reiterates that PGE entered different (and correct) heat rate data inputs into the REFLEX model when entering the heat rate data for its own RICE plant, but used incorrect heat rate data inputs into the REFLEX model when entering heat rate data for the generic RICE resource. This input error led REFLEX to overstate the heat rate of one technology at partial loads and incorrectly model the operating characteristics of that technology. This is one reason why, when compared to the other technologies, PGE concluded that there was no meaningful difference between capacity resources.

With respect to turnaround inputs, PGE again merely relied upon the data provided by Black & Veatch, but did not apply a comparison to its own technology inputs. PGE noted NIPPC's concerns about "the use of a constant available capacity for each month to model technology capabilities in REFLEX", but did not address this problem with the modeling.[8]

PGE correctly modeled the turnaround time inputs for its own RICE technology when entering the turnaround inputs for its own plant, but then relied upon incorrect information. Specifically, [redacted]

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8 Id. at 58.

[redacted]

This input error led REFLEX to mask the benefits associated with new RICE technology relative to the inflexibility of PGE's generic Frame CT resource. Once again, this is another reason why PGE incorrectly found no meaningful difference between capacity resources and chose to rely upon one generic flexible capacity resource in all 23 IRP scenarios.

In summary, these data-input errors underscore the need for additional analysis and verification of the REFLEX results because, as PGE has acknowledged, different capacity resources provide different costs, risks and benefits, which should be recognized in an IRP.

C. PGE Must Study All Available Transmission Options and Pursue a Least Cost Transmission Strategy

1. PGE's IRP Has Failed to Adequately Analyze Its Transmission Options

NIPPC continues to recommend that PGE should consider switching from a purely PTP transmission strategy to one that incorporates NITS to serve PGE's load because PGE's current transmission strategy may be imposing unnecessary and rapidly increasing costs upon its ratepayers.[9] PGE's transmission assets solely exist to benefit ratepayers and ensure that the least-cost and least-risk generation resources are used to serve load. NIPPC is also concerned that PGE is following a transmission strategy that will limit robust competition to serve PGE's growing resource need and be an impediment to a prudent resource acquisition strategy. This would further harm ratepayers by using resources that belong to customers to produce a result that biases future RFPs in favor of more expensive utility owned generation. If PGE refuses to

[9] NIPPC recognizes that, if PGE switches to NITS, then PGE would need to keep some PTP transmission to make wholesale sales and to participate in the energy imbalance market, and NIPPC is not recommending that PGE study giving up all of its PTP.

fairly evaluate all transmission options, then the Commission will need to even more carefully monitor PGE's RFPs to ensure that PGE is not able to rely upon ratepayer funded investments to discriminate against PPA bids. Regardless of whether PTP or NITS transmission is used, the Commission needs to ensure that PGE is using its transmission assets to benefit customers rather than utility ownership of generation.

NIPPC's position that PGE should study its long-term transmission options is supported by the Commission's IRP Guidelines, which expressly state that PGE should consider all its available transmission options. Guideline 1 says utilities must evaluate known resources for meeting the utility's load, including any options with respect to purchases and transmission of power.[10] Guideline 5 focuses on transmission, and requires utilities to include transmission costs for each resource being considered.[11] Thus, to comply with the Commission's IRP Guidelines, PGE must evaluate switching to NITS. NITS appears to be a lower-cost, higher benefit transmission strategy available to PGE on the BPA transmission system, which PacifiCorp, Avista Energy, and dozens of utilities in the Pacific Northwest already utilize.

NIPPC's initial estimates of near-term savings relied upon PGE's 2017 transmission holdings as reported by BPA, and indicate an approximate $14 million annual difference, and potential ratepayer savings, simply by using NITS rather than PTP. These short-term savings pale in comparison to the long-term savings for PGE ratepayers. Long-term, a NITS transmission strategy could lead to larger savings because NITS transmission costs are capped at

10 Re Investigation Into Integrated Resource Planning, Docket No. UM 1056, Order No. 07-002 at Appendix A at 1 (Jan. 8, 2007).

11 Id. at Appendix A at 5.

today's costs and will only increase as PGE load increases. This means that, even as PGE adds renewable projects to its generation fleet, PGE's transmission costs will remain stable. Adding even the one new large renewable wind resource in PGE's Action Plan exacerbates the problem with PGE's current approach to using only PTP transmission.

Renewable resources are particularly problematic from a PTP transmission perspective because they have much lower capacity factors. This means that, if PGE is buying PTP to the full nameplate capacity of each new renewable resource, ratepayers are buying larger and larger quantities of transmission that will only be needed a fraction of the time. For example, PGE's IRP seeks to add about 500 nameplate MW of wind resources. If PGE were a NITS customer of BPA, this renewable resource could be integrated into PGE's resource portfolio at potentially little incremental cost for transmission, assuming BPA has available transmission capacity. Under PGE's current use of only PTP transmission, PGE will purchase incremental PTP transmission for this resource, at a long-term fixed cost to ratepayers of over $10 million a year, which adds over $8 per MW hour ("MWh") to the next tranche of renewable resources.

NIPPC is not suggesting that PGE can walk-away from its existing PTP contracts with BPA or that PGE should immediately switch to from PTP to NITS. NIPPC's analysis of PGE's 2017 transmission holdings is merely illustrative of the potential benefits and demonstrates why PGE should at least comprehensively study the cost, benefits, risks, and logistics associated with a NITS strategy. NIPPC also recognizes that there may be costs or other potential challenges with a new transmission strategy, but the only way to determine the appropriate course of action is to conduct an unbiased, rigorous, and open cost-benefit study. NIPPC is suggesting, however, that PGE stop purchasing additional PTP transmission rights from BPA until it has fully evaluated an orderly conversion from PTP to NITS.

PacifiCorp embraced a similar evaluation of its transmission strategy years ago and now uses NITS on the BPA system to serve significant portions of its customer loads.[12] As NIPPC's Initial Comments addressed, the unique aspects of PacifiCorp's service territory may have led PacifiCorp to become an early adopter of a NITS strategy, but PGE may have crossed the "tipping point" where a similar approach would bring benefits to PGE's customers. PacifiCorp testified many times in recent years alongside PGE that it intends to bring on new renewable generation resources in the near term, and plans to use NITS for those new resources. PGE should consider following PacifiCorp's example.

PGE has likely already reached the "tipping point" where using NITS transmission will be cost effective due to its decision to purchase PTP transmission rights in advance of its actual transmission needs. NIPPC identified a discrepancy between PGE's stated PTP transmission rights on the BPA system and BPA's accounting of those rights. This discrepancy indicates that PGE has rights to as much as 700 MW of PTP transmission available on BPA's system in excess

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[12] Generally, utility transmission customers serving load must place all of their contiguous (discretely metered) loads on either NITS or PTP transmission. Customers using NITS to serve their loads can also use and retain PTP to make wholesale sales or participate in other activities, such as the Energy Imbalance Market. PGE operates a generally contiguous service territory, and NIPPC understands that PGE would need to use only NITS for its loads, but could keep PTP transmission to make wholesale sales and participate in the Energy Imbalance Market. PacifiCorp uses both NITS and PTP to serve its load because it has non-contiguous service territory. NIPPC understands that PacifiCorp's factual circumstances are different from PGE, but PacifiCorp's example is illustrative that a utility can move from a PTP to a NITS transmission strategy.

of PGE's nameplate generating capacity.[13] PGE notes these rights are in a deferred status, but PGE's IRP has analyzed neither the costs nor the wisdom of assuming this long-term obligation. As PGE points out in its Reply Comments, the amount of long-term PTP transmission rights that PGE currently holds on BPA's system is a significant consideration in the transmission analysis needed.[14]

These future PTP transmission rights could signal significant unnecessary costs that ratepayers will incur over PGE's extended planning horizon when PGE acquires additional resources. PGE's continued reliance on PTP transmission could result in over $27 million/year in added transmission costs that would be permanently avoided if PGE were to convert to NITS on BPA.[15] Other benefits would flow to PGE ratepayers by virtue of being a NITS customer of BPA instead of a PTP customer. For example, under NITS, a reduction in a single hour's peak load on the PGE system achieved using dispatchable demand response will result in a MW for MW reduction in PGE's transmission bill from BPA for that month.[16] These future recurring savings alone would, at a minimum, increase the cost-benefit ratio of certain demand response programs. For example, a 20 MW single hour reduction in hourly peak load on the PGE system (coincident with BPA's monthly billing peak hour) would reduce PGE's transmission bill from

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13 PGE may actually have over 5,000 MWs of long-term PTP transmission rights under contract on the BPA system, yet in its IRP PGE claims to have (and only needs) 3,670 MWs. PGE has refused to provide accurate information regarding its actual long-term PTP transmission rights.

14 PGE's Reply Comments at 114 ("NIPPC … overstates PGE's BPA PTP transmission position by approximately 700 MW, which if this alone is corrected in NIPPC's analysis, reduces the purported savings to approximately $0.").

15 NIPPC's Initial Comments at 20, n. 34.

16 If the demand response is dispatched on the hour of BPA's monthly peak billing hour.

BPA by over $35,000/month, but only if PGE were a NITS customer. Thus, the benefits to PGE ratepayers of converting to NITS are quantifiable, persistent, and will grow over time.

There is a separate and a key issue regarding PGE's use of PTP transmission. PGE has significantly more PTP transmission rights than it currently needs to serve its loads. The practical result is that PGE may be using ratepayer funds to hold and pay for PTP transmission rights and prevent them from being available to competing generation. This approach could harm ratepayers by requiring them to pay for potentially unnecessary transmission to ensure that they are served with more expensive PGE owned generation.

As is, PGE's IRP fails to meet Guidelines 1 and 5, and the Commission should not acknowledge the IRP's transmission plans. Due to the sizeable savings potential at stake, it is imperative that PGE at least analyze a transmission strategy involving NITS transmission. Thus, the Commission should order PGE to analyze short and long-term cost and benefits of relying on NITS before moving forward with any additional transmission resource acquisitions. Ratepayers should be considered the "owners" of these transmission assets, and PGE should review all reasonable alternatives to ensure that these assets are best used to facilitate the acquisition of energy and capacity regardless of ownership.

2. PGE Must Consider Alternative Transmission Strategies and Ensure that Its Customers' Transmission Rights Support the Least-Cost and Least-Risk Generation

PGE's failure to study its transmission options is important because PGE's transmission plans may require ratepayers to pay unnecessary costs and could result in discrimination against certain competitors in its RFPs. PGE makes several claims about a NITS conversion in its Reply

Comments that are misguided. A brief explanation of PTP and NITS service is needed to address PGE's concerns.

Both PGE and BPA have adopted the Federal Energy Regulatory Commission's ("FERC") pro forma Open Access Transmission Tariff ("OATT"), which defines two forms of firm transmission service: PTP and NITS.[17] PTP transmission is a "take or pay" contract meaning that PTP capacity holder must pay the full transmission rate, at all times, for the full term of the PTP contract. So, PGE pays for PTP whether or not it uses it. PTP reservations can only be used on a firm basis, if it is used to schedule power from the primary point of receipt to the primary point of delivery. NITS transmission can only be used to serve loads designated by contract as designated network loads. Instead of a single point of delivery, NITS customers usually have many points of delivery defined in their agreements. Unlike PTP, NITS is not a "take or pay" obligation. NITS is charged based upon actual use, but is limited to a NITS customer's own load. Thus, NITS cannot be used to support PGE's wholesale trading operations.

PGE's reliance upon PTP transmission necessarily requires PGE's ratepayers to purchase transmission in excess of PGE's need because PTP is a "take or pay" service. Thus, when PGE's resources are not running at full capacity, PGE has excess transmission rights that it does not need. NIPPC agrees with PGE that unused PTP can be redirected or resold, and that these incremental revenues benefit ratepayers; however, this must be considered in the context that they are mitigating PGE's "take or pay" obligation during times where PGE does not need PTP

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17 BPA has some variations from the pro-forma OATT, which are not relevant to this discussion.

transmission. NITS, on the other hand, would be based upon PGE's load and would relieve PGE's ratepayers from the entire amount of "take or pay" obligation that is beyond what is needed to serve load. NIPPC's recommendation also includes PGE keeping some PTP transmission to make surplus sales of generation in the market or other uses.

PGE has reserved surplus transmission rights, which it has postponed usage and holds in a deferred status. These rights, by definition, are in advance of need and PGE should study whether these surplus rights are the least cost and risk approach to PGE's long-term resource planning. PGE's reliance on purely PTP transmission distorts the IRP analysis and may allow PGE to discriminate against certain bidders in subsequent RFPs.

a. PGE's Actions Distort its IRP Analysis

In the IRP, PGE's assumption that it will perpetually pursue surplus transmission rights on the BPA system distorts PGE's long-term planning analysis and could subject PGE's ratepayers to enormous unnecessary costs, which are certain to grow over PGE's planning horizon. Ratepayers are paying for the costs of PGE's current surplus transmission holdings, even if they are postponed for future use. Although BPA's OATT allows PGE to postpone the start date of a PTP transmission right, BPA assesses one month's reservation charge for each year or partial year the service is deferred.[18] Thus, 700 MW of reserved transmission rights could cost PGE more than a million dollars each year in carrying costs, during which time the transmission is not benefiting PGE ratepayers.[19]

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18 BPA's OATT at 17.7, available at https://www.bpa.gov/transmission/Doing%20Business/Tariff/Documents/bpa_oatt.pdf.

19 BPA's current PTP demand charge of $1.489 x PGE's 700 MW of deferred transmission rights = $1,042,300.

This approach could only be prudent if there is a potential future value. For example, pre-purchasing transmission that can be used for future generation requirements and could avoid the need for PGE to pay for the construction of additional transmission upgrades. The appropriateness of this approach, however, should not be presumed, but PGE's IRP should explain its cost-benefit analysis and confirm whether its ratepayers or shareholders are paying the carrying costs for PGE's future transmission needs.

It is NIPPC's view that transmission assets overall belong to PGE's ratepayers. It is incumbent upon PGE in preparing its long-term resource plans to evaluate the best way that these transmission rights can benefit customers to ensure that the Company acquires the least-cost and least-risk resources regardless of ownership.

b. PGE's Actions Affect its Subsequent Resource Procurement Actions

PGE could use its surplus transmission to discriminate against non-utility owned bids in its next RFP. If PGE does not make its reserved transmission capacity available to RFP bidders, PGE will be using ratepayer money to ensure that the only generation resources that can have their power wheeled to PGE will be the generation owned by PGE. In the past, PGE has required non-utility ownership bidders to purchase expensive transmission to support their bids. PGE needs to demonstrate that it is not using PTP to favor its own resources. This kind of business practice can be expected to lead to the selection of higher-cost and higher-risk projects, a risk to PGE ratepayers. Moreover, PGE's reservation of transmission rights on its own or third-party providers' system can make it difficult or impossible for competitors to purchase transmission to wheel their power to PGE.

For example, PGE's excess transmission purchases have already constrained access to transmission for prospective bidders and other IPP sales. PGE's currently unused transmission purchases have effectively consumed significant amounts of the incrementally available firm transmission from the east side of the state to PGE's loads. Thus, many IPP projects will not be able to secure transmission and participate fairly in PGE's RFP or otherwise sell power to PGE. As noted above, PGE has acquired significant quantities of transmission rights above its near-term need. If those transmission reservations are not available to IPP generators seeking to bid into PGE's RFPs or sell power in bi-lateral transactions, then PGE is using ratepayer funds to ensure that PGE's self-build options win.

In addition to PGE's over-reservation of PTP transmission, there is the separate issue of whether NITS or PTP is the appropriate type of transmission in the first place. All utility and non-utility owned bidders must absorb the costs of the expensive PTP transmission required by PGE. For example, a solar project may have to add $12 MWh to its bid price just to cover the cost of PTP transmission on BPA's system. For a project that is only generating 25% of the time, the full costs of PTP transmission could make a project uneconomic, or at least add considerable and unnecessary costs to ratepayers to meet the aggressive standard of Oregon's renewable portfolio standard.

If PGE were a NITS customer of BPA, however, these projects could be designated network resources to PGE's NITS agreement with BPA, saving PGE ratepayers this entire incremental transmission cost and allowing a wider pool of resources to compete. Alternatively, PGE could make its future transmission positions available to third parties preparing bids into

PGE's RFPs. This is consistent with the concept that PGE's transmission rights belong to its ratepayers, but is not consistent with PGE's past RFPs.

In short, PGE's reliance upon PTP and habit of reserving transmission rights for projects it intends to build should be best understood as prudent only under a world view where PGE owns all the generation resources used to serve its load. Because PGE's IRP should be ownership agnostic, PGE must begin considering different transmission strategies that do not discriminate in favor of utility-owned generation and could lower the costs of transmitting the significant amount of renewable resources that will be required in the future.

3. PGE Has Not Provided Any Grounds Not to Evaluate Transmission Options

PGE argues that even contemplating conversion to a "BPA Network Integrated Transmission Service is without merit" and provides four reasons to exclude considering a NITS conversion in the IRP process.[20] First, PGE claims that PTP and NITS are not comparable. Second, PGE notes that NIPPC has assumed savings without balancing any related costs. Third, PGE suggests that NITS is incompatible with EIM. Finally, PGE claims that switching to a NITS strategy is an untested idea. None of these assertions provide support for PGE's refusal to comply with the Commission's IRP Guidelines, or at least conduct a fair and balanced study of such a switch. Each of PGE's claims is addressed in detail below.

a. PTP and NITS are Comparable Transmission Products

PGE's assertion that PTP and NITS are not comparable is incorrect because the salient difference between PTP and NITS is how they are priced, and the pricing supports NIPPC's

[20] PGE's Reply Comments at 113-115.

position. As explained above, PTP is considered a "take or pay" transmission product because PGE will pay for PTP whether it uses the service or not, and with NITS PGE only pays for what it uses to serve load.

Both PTP and NITS are flexible, just in different ways. For example, PGE points out that PTP is re-directable and re-sellable, but fails to acknowledge that secondary uses for unneeded PTP transmission merely seek to mitigate PGE's costly take-or-pay obligation under PGE's PTP strategy, or used to market generation surpluses for the benefit of ratepayers.[21] Additionally, because this kind of flexibility can only by accessed on a non-firm basis, it may not be as valuable and it is unclear how much of the initial costs can be recovered. Conversely, NITS can be more flexible in certain circumstances and allows ratepayers to avoid paying for transmission service that PGE does not need on many hours of the year.

In the end, NIPPC has not and should not be required to account for all potential costs and benefits related to a switch to NITS. The entire purpose of doing a cost-benefit study is to account for all potential costs, benefits, risks and operational impacts, and PGE has a duty to study its transmission options.

b. A NITS Transmission Strategy Is Compatible With the EIM

There is no reason why PGE cannot participate in an EIM using BPA NITS transmission to serve its load. PGE, claims that "using NITS on the BPA system is incompatible with transfers into the Energy Imbalance Market."[22] Yet, PacifiCorp is currently participating in the

21 Id. at 114.
22 Id. at 115.

EIM and PacifiCorp is also a large NITS customer of BPA, having over 2,000 MW of network resources designated under its NITS service on the BPA system.

PGE also states that "[a]s part of its market participation [in the EIM], PGE will make portions of its transmission rights available on BPA's system to facilitate EIM transfers"[23] and that PGE could not make such rights available for transfers under NITS should PGE convert to NITS under BPA. These statements are not relevant, because PGE appears to refer to the rights that PGE holds for power sales, and not transmission rights on BPA's network held to serve PGE's load. To be clear, NIPPC supports PGE's retention of the existing PTP transmission rights necessary to make surplus sales or participate in the EIM, and reiterates that a robust study of PGE's transmission options could reveal opportunities for PGE to begin converting to NITS to support its load.

c. BPA Will Accept a NITS Request From PGE

PGE appears to argue that BPA may not allow it to become a NITS customer of BPA, which is wrong and misleading. BPA is required to provide NITS to any eligible customer that requests network service, which could certainly include PGE. PGE could undertake the process that is thoroughly outlined in FERC's pro forma OATT, and has been adopted by both BPA and PGE. At a minimum, PGE cannot claim that BPA would deny a NITS request and discriminate against PGE without even first making the request to BPA.

The process laid out in BPA's OATT could even be implemented before PGE acquires transmission service for its next renewable resource. NIPPC agrees that PGE would need to

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23 Id.

move deliberately and carefully, but once PGE has executed a NITS agreement with BPA and been assured that its reservation was first in the queue, and designated network load, PGE could begin making scheduling power deliveries using a NITS reservation instead of PTP reservation.

BPA's OATT requires BPA to offer both PTP and NITS to any eligible customer on a non-discriminatory basis. PGE concedes that BPA's OATT allows PGE to use NITS, but offers a variety of concerns that are without foundation.[24] For example, PGE maintains that NIPPC's idea of using NITS for a large off-system load like PGE is "completely untested", belies the fact that every single utility customer of BPA is an "off-system" load just like PGE. While many BPA customers rely upon PTP, some of these off-system NITS customers of BPA are quite large, such as Clark County PUD's more than 900 MW system.

Contrary to PGE's claims, converting to NITS would neither give BPA operational control over PGE's resources nor complicate BAA balancing operations. BPA's OATT requires NITS customers to agree to make their designated network resources available to BPA for redispatch if necessary to maintain system reliability and ensure uninterrupted service to firm load.[25] Two things worth noting here. First, BPA must fully compensate its NITS customer for any resulting costs. Second, this is actually a benefit of NITS over PTP for a utility like PGE because under PTP service the transmission provider has no such redispatch right, and the transmission provider must instead curtail a PTP transmission schedule without compensation,

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24 PGE's Reply Comments at 114-15.

25 See BPA OATT at 33.2 ("to the extent the Transmission provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources").

which has a risk of interrupting service to load. Under NITS, customers stand ready to redispatch their resources for the reliability of the of service to all NITS customers, secure in the knowledge that they will be compensated by the transmission provider in the event there are reliability concerns.[26]

Despite this benefit of NITS over PTP (more reliable service to load), PGE claims that NITS could somehow complicate its BAA balancing operations, yet offers no evidence or examples of how this might happen. By way of response, NIPPC points out that PGE intends to join the EIM and will voluntarily make its resources available to the EIM operator for redispatch at five-minute intervals for both reliability and economic reasons. PGE has not explained why giving BPA the right to redispatch PGE's resources under NITS for the limited reason of maintaining system reliability somehow complicates "PGE's own BAA balancing operations",[27] whereas participation in the EIM does not raise any such concerns.

PGE mischaracterizes NIPPC's recommendation to study all its transmission options by focusing on discrete examples connected to the most extreme NITS position possible to PGE.[29]

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26 See BPA OATT at 33.3 ("Cost Responsibility for Relieving Transmission Constraints Except as provided in Attachment M, when the Transmission Provider implements least cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Network Load.").

27 PGE's Reply Comments at 114.

29 NIPPC notes that PGE could sell all of its existing unexpired PTP rights, if the benefits of switching to NITS made that option cost effective, or could hold a portion of any unexpired PTP rights to support its marketing activities. At a minimum, NIPPC suggests PGE *consider* switching to NITS for at least its *load*. NIPPC also notes that all but 270 MW of PGE's active status PTP contract rights will expire by 2021, so PGE could simply allow them to expire and begin switching load to NITS via attrition.

Any attempts by PGE to draw conclusions about the feasibility of a NITS strategy is akin to placing the cart before the horse.

III. CONCLUSION

The IRP process is fundamental to the Commission's role in ensuring the Company's services to ratepayers are properly valued. The Commission can only perform its core statutory duties if PGE provides comprehensive and transparent information. The IRP is not an end in itself, but instead provides the justification for an action plan that leads to billions of dollars of investments on behalf of and paid for by ratepayers. NIPPC is concerned that the IRP inadequately considers all available options to ensure that ratepayers are served with the least-cost and least-risks resources. The success of PGE's next RFPs and the ultimate value to customers will be profoundly influenced by the credibility and rigor of this IRP. Therefore, NIPPC recommends the Commission not acknowledge the transmission plans and capacity resource components of the IRP, without requiring additional analysis by PGE, but acknowledge PGE's near term renewable resource need to allow the Company to take advantage of the potentially low cost renewable resources.

Dated this 12th day of May 2017.

Respectfully submitted,

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Of Attorneys for Northwest and
Intermountain Power Producers Coalition

Attachment A

April 25, 2017

TO: Sidney Villanueva
Northwest and Intermountain Power Producers Coalition (NIPPC)

FROM: Patrick Hager
Manager, Regulatory Affairs

PORTLAND GENERAL ELECTRIC
LC 66
PGE Response to NIPPC Data Request No. 111
Dated April 18, 2017

Request:

Please provide the following supporting information for the Flexible Capacity Analysis conducted by E3 as presented in Chapter 5.3, Flexible Capacity analysis.

A. Please provide a copy of the final report delivered to PGE by E3 detailing the nature, scope, design, and findings of the analysis in which E3 employed their proprietary REFLEX model to support PGE's Flexible Capacity analysis.

i. If no such final report exists, please provide copies of all correspondence, memorandums, data exchanges, and emails between PGE and E3 identifying the derivation of key analytic assumptions specifying the PGE system modeled in REFLEX, the scope and depth of scenarios analyzed, and the specific findings of E3 pertaining to PGE's flexible capacity analysis

C. Please provide a copy of the professional services contract between E3 and PGE specifying E3's support and involvement in developing the 2016 IRP Flexible Capacity analysis using REFLEX, and the nature and amount of all compensation paid to E3 for assistance in developing such Flexible Capacity analysis.

i. If no such contract between PGE and E3 was ever executed, please describe in detail the scope of E3 involvement and support to PGE in developing the Flexible Capacity analysis and an itemized accounting of all compensation paid to E3 by PGE specifically for E3's assistance in developing the Flexible Capacity analysis

Response:

A. PGE objects to this request on the grounds that it seeks information not relevant to this docket. Subject to and without waiving its objection, PGE responds as follows.

   Attachment 111-A contains the final presentation provided to PGE from E3 regarding REFLEX modeling exercises of the PGE system. In addition to the REFLEX analysis described in Section 5.3 of the 2016 IRP, this deliverable included material that was not utilized in the 2016 IRP and material that was preliminary and not confirmed by PGE. Pages containing material not utilized in the 2016 IRP have been redacted. Attachment 111-A is protected information subject to Protective Order 16-408.

C. PGE objects to this request on the grounds that it seeks information not relevant to this docket.

LC 66

Attachment 111-A

Provided in Electronic Format only

Protected Information Subject to Protective Order No. 16-408

E3 Final Presentation