BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 66

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

I. INTRODUCTION

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") 2016 Integrated Resource Plan ("IRP"). NIPPC recommends that the Commission 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 resources, the Commission should recognize that PGE has a capacity need that is best served with short to medium term power purchase agreements ("PPAs"). Regarding transmission, the Commission should direct PGE to provide transparency of its transmission assets and an analysis on a converting its point to point service to network transmission service on Bonneville Power Administration ("BPA"). The long term risk associated with PGE's

[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/.

preferred portfolio justifies additional analysis from PGE, and the Commission should not acknowledge the IRP, without requiring such additional analysis.

The IRP fails to accurately evaluate or even distinguish between different flexible capacity resources. PGE ignores key distinguishing attributes between the resource technologies considered, and relies upon inaccurate data inputs and assumptions to justify its determination that there is no meaningful difference between flexible capacity resources. The data PGE used in its modeling is simply not accurate and cannot reasonably be relied upon. As such, PGE has failed to analyze the different costs, risks, and benefits associated with different physical capacity resources. This "failure" provides PGE with no information on the value of different flexible resource attributes, which will allow PGE to exercise inordinate discretion to select whatever resource it wants in its next request for proposal ("RFP").

The IRP offers only status quo options for adding new transmission, i.e., purchasing even more expensive long term transmission from BPA or building new transmission lines. By not considering alternative transmission opportunities, such as converting a portion of its transmission to less expensive network service, PGE has foreclosed analyzing a strategy that other utilities, like PacifiCorp, have embraced. PGE's portrayal of its transmission in this IRP also fails to acknowledge its transmission planning strategy and its ability to accept additional power via BPA's balancing authority. Switching to network service could also lower the cost of renewable acquisitions and reduce PGE's ability to use transmission issues to bias RFPs in favor of utility owned generation.

These analytical infirmities are particularly troubling, because they lead PGE to determine that a major long-term investment in a wind plant in 2018 along with a gas plant in 2021 is PGE's least cost and risk option. While the initial need for increased renewables in 2018 seems reasonable in light of SB 1547, the conclusion to build a gas plant in 2021 seems out of touch in the regulatory context for this IRP. With so much environmental policy uncertainty, PGE should consider "renting" resources instead of "buying" them.

NIPPC points out that there is no analysis of short-term opportunities in PGE's IRP, and PGE therefore cannot determine what kind of impact short-term contracts might have on PGE's projected needs. NIPPC is not disputing PGE has an increased need for renewable power and a capacity need in the near term, but PGE has not adequately analyzed whether its short-term need can be met with short-term purchases rather than a long-term investment in a new gas plant or owned renewable generation. In addition, PGE's assumptions about market availability artificially inflate PGE's load forecasts, especially in the long term. This exacerbates the need for the consideration of short-term options.

Finally, PGE's IRP exaggerates the benefits of utility owned generation and the risks associated with PPAs. Although the IRP states it is "generally agnostic with respect to ownership structure"[2] the overall content and conclusions of the IRP suggest the opposite. PGE highlights any and every conceivable theoretical risk to the utility associated with PPAs, while completely ignoring the tangible risks to ratepayers due to utility ownership, including construction cost overruns, early plant closure, resource underperformance, unexpected repairs and capital replacements, etc. As demonstrated in the Carty episode as well as the early closures of Trojan and Boardman, these risks are unique to utility owned projects, as opposed to PPAs.

II. 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

[2] PGE's 2016 IRP at 222.

acknowledged plan.[3] 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.[4] The Commission also lists twelve procedural guidelines. If a utility's 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."[5] 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."[6] 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,

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3 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).

4 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 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).

5 Order No. 89-507 at 3.

6 Id. at 2.

then the utility should explain its balance of those two characteristics in selecting the best strategy."[7]

Although PGE's previous two IRPs have both 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 alternatives to physical compliance to meet its renewable portfolio standard ("RPS") compliance goals.[8] Moreover, Commission staff ("Staff") determined that PGE's load and natural gas forecasts were overstated, and expressed concerns about PGE's evaluation of demand response and energy efficiency.[9]

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.[10] 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.[11] The Commission further directed PGE to conduct a comprehensive analysis of all flexible capacity resource options.[12] Finally, the Commission suggested PGE expand its consideration of market purchases, energy efficiency,

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7 Id.

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

9 Re Portland General Electric Company, 2009 Integrated Resource Plan, Docket No. LC 48, Proposed Order at 5, 20, 22 (Nov 12, 2010).

10 Re Portland General Electric Company, 2013 Integrated Resource Plan, Docket No. LC 56, Order No. 14-415 at Appendix A at 2 (Dec. 20, 2014).

11 Id. at 5-6.

12 Id. at 12.

demand response, and distributed generation in its next IRP.[13] As outlined below, PGE has not credibly adhered to the basic IRP Guidelines or these past IRP flaws.

III. COMMENTS

PGE's 2016 IRP does not properly evaluate the broad range of resources available in favor of rushing forward with ownership of a new gas generation resource like Carty 2. PGE has also failed to take the Commission's guidance from 2010 and 2014 to heart, and is moving forward with a plan designed to promote physical acquisition of owned gas and renewable resources over a potentially lower cost and risk approach. PGE's limited analysis does not clearly articulate its long-term resource needs, and either ignores or undermines the value of shorter-term and non-owned resource options.[14] Similarly, PGE does not even consider the option of switching to BPA network transmission service, which could be lower cost and risk as well as making it more difficult for PGE to use transmission access issues in an RFP to discriminate against PPAs.

1. The IRP Fails to Adequately Evaluate Different Resource Options

PGE has failed to properly analyze different resource options by claiming that there is no meaningful difference between different dispatchable capacity resources, and NIPPC recommends that the Commission order PGE to re-do its flexible capacity resource analysis. By failing to adequately distinguish different capacity resources, PGE concludes there is no meaningful difference. This makes it difficult to ascertain what kinds of impacts shorter options could have, and impossible to determine PGE's actual resource needs and the least cost/risk portfolio. This IRP does not place interested potential bidders on notice as to what kind of

13 Id.
14 See e.g., PGE's 2016 IRP at 222 (describing PPA and tolling agreements as "the two primary market alternatives for mid- and long-term contracts for wholesale electricity" without addressing shorter term options).

resources PGE needs or the value of different capacity resource attributes, and it cannot provide sufficient guidance for either PGE or an independent evaluator to fairly evaluate different resources in an RFP. Thus, the result is an overbroad IRP that will most certainly lead to an unworkable RFP, or at least an RFP that only works for whatever utility owned generation that PGE wishes to acquire.

PGE analyses three different types of flexible capacity resources, but all 23 IRP scenarios exclusively incorporate only one flexible dispatchable resource technology, the "generic" capacity resource, because PGE found no meaningful difference between flexible resources.[15] Thus, PGE claims that all flexible capacity resource technologies are so similar that PGE assumed the use of a large-frame simple-cycle combustion turbine in all of its IRP scenarios. By using only a single generic capacity resource (regardless of which resource displays the lowest lifecycle fixed and variable operating costs), PGE has no information regarding the value of different resource attributes to its system. For example, PGE cannot tell which resource technology will reduce fuel costs (and perform better in a high gas price or carbon regulation future), reduce renewable curtailments, increase the Company's flexibility in operating its existing resources, etc.

The failure to properly identify the least cost/risk resource portfolio matters because these critical components will be evaluated in future RFPs to acquire new generation, either owned or "rented." The IRP fails to clearly define its resource need and what types of resources best fit any need, which means that PGE is free to evaluate the market through a "robustly designed

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15 PGE's 2016 IRP at 30, 801-02; see also Attachment A- PGE Response to NIPPC Data Request Nos. 30, 31.

RFP" instead.[16] With an IRP that has not analyzed the specific impacts of different resource types, PGE will have unfettered discretion to subjectively make up the impact, benefits, and costs of different resource types. Absent removing PGE from running the RFP, there cannot be a fair analysis of different resource types in the RFP, if PGE fails to develop objective cost and benefit information in the IRP. There can be little doubt that, if PGE is allowed to use the RFP process as a substitute for a robust IRP, then PGE will acquire whatever owned resources it wants irrespective of cost or risk.

Despite PGE's conclusion that there is no material difference between flexible capacity resources and that 23 IRP scenarios should only incorporate PGE's "generic" flexible capacity resource, NIPPC believes that a robust IRP analysis could (or at least provide better information for an RFP to) identify the lowest cost and least risk resource. For example, the lower operating costs and emissions offered by the technology used in Port Westward II could more than offset its increased capital costs, by reducing exposure to future fuel and carbon prices. Neither NIPPC nor the Commission, however, can know what is best because this level of comparison is absent from PGE's IRP. Analyzing the fixed *and* variable costs over the life cycle of different resource technologies is the foundation of integrated resource planning. Because PGE's 2016 IRP lacks this foundation, its conclusions are not supportable, which should result in the Commission refusing to acknowledge the Action Plan's generic capacity resource.

a. PGE's Analysis Is Too Narrow and Fails to Consider All Known Resources Available to Meet PGE's Load

PGE has failed to examine even a representative subset of available flexible resources, much less a comprehensive one. PGE's IRP evaluates only three resource technologies for

16 PGE's 2016 IRP at 226 ("a robustly designed RFP will take full advantage of the numerous resource alternatives available in a competitive market, allowing the Company to seek out and deploy all resources that will bring the best value for customers").

providing incremental flexible capacity: 1) a combined-cycle gas turbine; 2) a reciprocating internal-combustion engine; and 3) a very large-frame simple-cycle combustion turbine. By relying on flawed REFLEX modeling, PGE "substantiates" its incorrect determination that there is no meaningful difference between these technology alternatives. This determination permits PGE to base its least cost capacity resource decision solely on fixed costs of construction and a narrow definition of operational parameters.[17] In short, PGE's conclusion that a simple-cycle combustion turbine is the "least-cost' capacity resource is flawed because it is the only flexible capacity resource PGE considered.

The three resource options PGE considered are worthy of further discussion.[18] First, a combined-cycle ("CCCT") plant is very efficient, but relatively inflexible. This is the technology PGE has proposed for a Carty 2 plant. Second, a reciprocating internal-combustion engine ("RICE") plant is moderately efficient, but very flexible. This is the kind of technology in PGE's existing Port Westward II plant. Third, the large-frame simple-cycle combustion turbine ("Frame") is inefficient, but moderately flexible. This is the kind of technology PGE proposed in Carty 3 combustion turbine plant currently undergoing review by the Oregon Energy Facility Siting Council ("EFSC"). The operating characteristics for the most flexible of these resources, i.e., RICE, was misrepresented in PGE's analysis, and leads to PGE requesting acknowledgment of a generic capacity Frame resource that is not shown to be least cost and risk.

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17 See PGE's 2016 IRP at 216. ("Figure 7-13 also shows that the *cheapest* capacity resource on a $ per kW basis is an SCCT, followed by a CCCT. Because of their least-cost, the frame SCCT is the technology selected to fill generic capacity needs in PGE's portfolio analysis").

18 PGE requested that Black and Veatch characterize a fourth flexible resource technology, the GE LMS100 combustion turbine, but there is no evidence that the LMS100 was ever modeled or otherwise analyzed in the IRP. Attachment A - PGE Response to NIPPC Data Request No. 2.

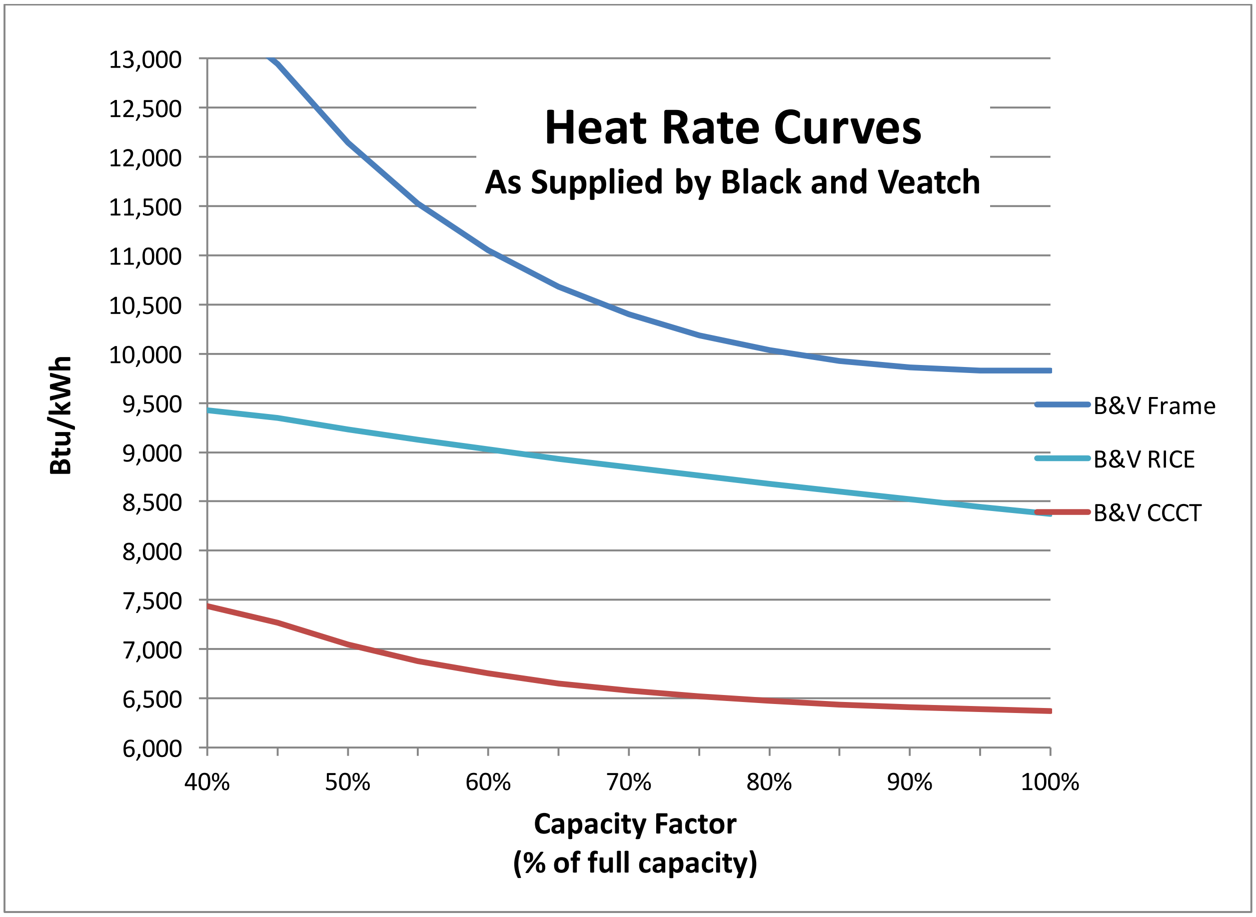
b. PGE's New Model Relies Upon Incorrect Data Assumptions

PGE used a new model (REFLEX) in this IRP, which was not configured to produce accurate results. The REFLEX model depends on many detailed resource-specific input assumptions, including six that directly capture the capability of a specific resource technology to effectively integrate renewable resources: 1) efficiency (heat rate) curve; 2) minimum up time; 3) minimum down time; 4) startup costs; 5) upward ramping capability; and 6) downward ramping capability.[19] PGE's input assumptions for some of these critical inputs misrepresent important operating characteristics of the RICE technology, contradict information provided to PGE by Black and Veatch, and are not supported by the data PGE uses to represent its own RICE technology at Port Westward 2.

i. Inaccurate Heat Rate Curve Specified for RICE Technology in the REFLEX Model

By substituting an incorrect heat rate curve assumption in the REFLEX model, PGE generates the improper conclusion that the RICE technology is as inefficient as the Frame technology. This is inaccurate and contrary to the efficiency information PGE specified for its own Port Westward 2 and the generic information from Black and Veatch, both of which very closely track each other. This is demonstrated with the following two charts. The first illustrates generic information provided from Black and Veatch. The second compares information entered into the REFLEX model by PGE.

[19] PGE's 2016 IRP at 132-145.



This chart illustrates the heat rate curves provided by Black and Veatch for the three resources PGE considered.[20] The heat rate of a resource is a measure of efficiency that expresses how much natural gas must be burned to generate one kilowatt hour ("kWh") of energy. So, the lower the heat rate, the more efficient the resource. Published heat rates can be misleading when evaluating flexible capacity, because most resources (and especially simple-cycle combustion turbines like PGE's proposed Carty 3 plant) can suffer large efficiency losses when operated at less than full load. Conversely, the RICE technology (identical to PGE's existing Port Westward 2 plant) can operate at full load efficiencies across a wide range of output. Because flexible capacity resources are frequently dispatched at partial load to supply upward ramping reserves,

[20] PGE's 2016 IRP at 212, Appendix K.

correctly modeling heat rate characteristics is critical in this IRP modeling. A higher heat rate resource results in higher fuel costs and higher carbon prices. Yet, PGE's analysis and portfolio modeling failed to capture these higher costs and risks.

Despite the heat rate advantage of the RICE technology, as indicated in Black and Veatch's information in Attachment K to the IRP, and depicted in the chart above, PGE determined through its own REFLEX analysis that there were no material differences between the resources, and selected the Frame resource as its "generic" capacity resource used in all 23 IRP scenarios.[21] Upon examination, NIPPC determined that critical REFLEX inputs were incorrectly specified by PGE for the RICE technology. PGE substituted erroneous data inputs for the RICE technology, in contradiction to both Black and Veatch's parameters documented in Attachment K and PGE's specifications for Port Westward 2.

The following graph depicts the magnitude of PGE's incorrect heat rate specification for the RICE technology in the REFLEX model studies.

[21] PGE's 2016 IRP at 30, 801-02; see also Attachment A- PGE Response to NIPPC Data Request Nos. 30, 31.

[redacted]

This graph compares the heat rate curve that PGE specified for their own Port Westward 2 and the generic RICE heat rate curve from Black and Veatch, and depicts the relatively flat heat rate curve and efficiency characteristics expected from the RICE technology. The graphs show the heat rate curve used by PGE for a new RICE generator in its REFLEX model, and depicts the efficiency losses at partial load.[22]

[22] See PGE Response to OPUC Data Request No. 035, Confidential Attachment 035-A (REFLEX data base).

ii. Inaccurate Turnaround Time used for RICE Technology in REFLEX Model

By substituting incorrect turnaround assumptions, PGE likewise generates the improper conclusion that the Frame technology is equally as flexible as the RICE technology. These turnaround time inputs, like those for heat rate, are inaccurate and contrary to the flexibility information PGE specified for its own Port Westward 2.

[redacted]

This table compares the minimum up and down times entered into REFLEX for the three resources PGE considered.[23] The capability of a resource to start and stop frequently (commonly referred to as turnaround time) is a critical component of its value. It is commonly known in the industry that the RICE technology requires only one minute of up time when started and only five minutes of downtime, which provides unique advantages. PGE correctly input these parameters in the REFLEX model when representing their own RICE resource at Port Westward 2, but input different numbers for a new RICE resource.[24]

iii. REFLEX Model Ignores Key Distinction Between Frame and RICE Technology

The REFLEX model also ignores a key distinction between the Frame and RICE technologies that should influence the flexibility modeling. Most thermal capacity resources can suffer significant capacity reductions when operating at higher ambient temperatures.[25] Frame

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23 Id.

24 Id.

25 See Combustion Engine vs Gas Turbine: Ambient Temperature, WARTSILA, http://www.wartsila.com/energy/learning-center/technical-comparisons/combustion-engine-vs-gas-turbine-derating-due-to-ambient-temperature.

generation will suffer more than a 10% loss in dispatchable capacity at 95° F, while the RICE technology maintains its rated capacity at high ambient temperatures.[26] At higher ambient temperatures, the Frame loses dispatchable capacity relative to the RICE technology. Yet, this characteristic does not appear to be included in PGE's analysis.

c. PGE's Analysis Ignores Future Cost Risk

Because PGE only considered its "generic" flexibility capacity resource in the scenario analysis using the different AURORA model, PGE's IRP avoids any examination of the different exposure to future fuel prices and CO_2 emissions between flexible capacity resources, which is not inconsequential. The heat rate penalty of operating PGE's generic capacity resource compared to the RICE technology at Port Westward 2 shows fuel costs and CO_2 emissions are almost 50% higher for the generic capacity resource than the RICE technology, when both resources are operated similar to the way PGE operates Port Westward II. To fully mitigate this CO_2 difference, PGE would need to acquire additional carbon-free resources equivalent to 70 MW of Gorge wind.

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26 See e.g., Catalog of CHP Technologies at 2-12, EPA COMBINED HEAT AND POWER PARTNERSHIP https://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies_section_2._technology_characterization_-_reciprocating_internal_combustion_engines.pdf.

	Column 1	Column 2	Column 3
	Port Westward 2 (Actual 2015)	Generic Capacity Resource Dispatched Similar to Port Westward 2	Difference
Actual hours dispatched	3,367 hours[1]	3,367	None
Actual Net Generation	342,205,000 kWh[1]	342,205,000 kWh	None
Average Capacity Factor across all hours dispatched	46.2%[1]	46.2%	None
Actual Heat Rate	8691 Btu/kWh[1]	12,750 Btu/kWh[3]	4059 Btu/kwh (+47%)
Actual Fuel Consumption	3,005,213 MMBtu[1]	4,358,312 MMBtu	1,384,105 MMBtu
Actual Annual Fuel Cost	$10,009,746[1]	$14,260,397 million	+$4,529,794 million (+45%)
Actual average annual fuel price	$3.272 MMBtu[1]	$3.272 MMBtu	None
Approximate CO2 emissions[2]	179,000 tons	255,000 tons	+80,000 tons (45%)
Additional Wind Resources Required to offset increased CO2 emissions			Approx. 70 MW nameplate
[1] Portland General Electric Company, 2015 FERC Form 1, p. 403.1			
[2] Actual fuel consumption (MMBtu) x 117 lbs (CO_2 per MMBtu)			
[3] Attachment K, Table 3-4, Column 8-Row 2, Fuel Consumption versus Output: x = 106,000 kw			

This table compares actual operations at Port Westward 2 in 2015 to approximate costs if PGE's generic capacity resource had been operating, and was dispatched like Port Westward 2 was dispatched, in 2015.[27] This shows a clear disparity fuel costs and CO_2 emissions associated with operating PGE's "generic" resource compared to the RICE technology. And this chart reflects only one year. By failing to include the relative future costs of fuel and carbon, PGE's analysis not only fails to adequately evaluate the different resources, but also forecloses any accurate evaluation of PGE's plans to meet its long term environmental requirements.

27 Portland General Electric Company FERC Financial Report at 403.1 available at http://investors.portlandgeneral.com/ferc.cfm (2015 FERC Form 1 hyperlink); PGE's 2016 IRP at Attachment K.

2. The IRP Fails to Adequately Analyze Transmission Opportunities and Ignores the Possibility of Converting Transmission from Point-to-Point to Network

PGE's description of its transmission position in the IRP fails to provide sufficient insight into its transmission planning and capacity to accept power generated in neighboring Balancing Authority Areas, especially BPA. PGE suggests only two options for transmitting power from existing and future remote resources to PGE's loads: 1) purchasing long-term Point-to-Point transmission service ("PTP") from BPA for the full nameplate capacity of each existing and new resource as PGE does today; or 2) building new transmission lines from remote resources to PGE's loads (e.g., reviving PGE's tabled plans for the Southern Crossing transmission line, which the Commission acknowledged in 2009).

PGE has overlooked a third option for managing transmission, that may be pursued at significantly lower cost. This third option would be for the company to convert existing transmission service on the BPA system from PTP service under Part II of the BPA Open Access Transmission Tariff ("OATT") to Network Integration Transmission Service ("NITS") available under Part III of the BPA OATT. The Commission should refuse to acknowledge PGE's IRP because it has failed to analyze the potential cost savings and other benefits associated with switching from PTP to NITS service, and should instead direct PGE to conduct a robust analysis of its transmission options in a re-constituted IRP. Given the importance of transmission issues, as they relate to generation purchases, the Commission should also decline to acknowledge any plans to own new gas generation or significant amounts of new renewable generation until PGE has completed such a transmission analysis.

a. An NITS Strategy Could Result in Significant Savings for Ratepayers and Reduce PGE's Ability to Favor Owned Resources in RFPs

PGE currently holds over 4,400 MW of long-term firm PTP transmission rights on the BPA system.[28] PGE's ratepayers currently pay BPA a fixed cost of approximately $95 million per year.[29] If PGE were to replace this existing PTP service with NITS service, PGE ratepayers' fixed cost obligation to BPA could be reduced to about $81 million per year, approximately 15% less.[30] Unlike PTP transmission, the cost of NITS would remain stable over the IRP planning horizon, and would not increase with additional PGE resource additions.

	BPA Point-to-Point Transmission (PTP)	BPA Network Transmission (NITS)
PGE Monthly Billing Factor	4,400 MW	Varies based on load
Average Annual PGE Monthly Billing Factor (NITS is 2015 Actual)	4,400 MW	3,230 MW [1]
BPA Monthly Transmission Rate [2]	$1,790 MW	$2,085 MW
Annual PGE Cost of BPA Transmission	$94.5 million	$80.8 million
[1] Source: Portland General Electric Company 2015 FERC Form 1 page 401b		
[2] Source: BPA https://www.bpa.gov/Finance/RateInformation/Pages/Current-Transmission-Rates.aspx		

28 PGE may hold over 5,000 MW of BPA long-term PTP transmission. NIPPC has sought to ascertain the exact amount of BPA transmission that PGE holds, but PGE has refused to provide this information to date. PGE has provided other information showing that it has about 3,670 MW BPA PTP transmission. PGE Response to ICNU Data Request No. 019. PGE's actual BPA PTP transmission appears to be much greater. See BPA Transmission Rate Case Study Documentation available at https://www.bpa.gov/secure/Ratecase/openfile.aspx?fileName=BP-18-E-BPA-08+Transmission+Rates+Study+and+Documentation.pdf&contentType=application%2fpdf) (PGE has 4,430 MW of LT PTP reservations and all but 25 MW do not expire until later than 2019.). NIPPC may address in subsequent comments whether PGE has failed to inform the Commission that it has reserved extra unused transmission that may be more than needed for Company owned Carty 2 and 3 generation projects.

29 See chart infra comparing PGE 2017 transmission costs with current BPA rates.

30 Id. These are only estimates of one aspect of the cost savings, and NIPPC recognizes that these numbers fail to include all potential costs and benefits of such a significant change like switching to NITS. A full and more accurate estimate can only occur after PGE commits the resources in the IRP to study it.

If this potential savings were not enough, there is a second reason for expanding consideration of its choices in transacting with BPA. Converting from PTP to NITS would remove an inherent bias against renewable resources and shorter-term contract resources. With the change, non-utility generators would no longer be saddled with onerous transmission delivery costs; costs that PGE would presumably decline to charge itself in an RFP.

Under PTP, the transmission service rights accrue to generation resources and the service is charged based upon the capacity reservation associated with each specific generator. Under NITS, the transmission service rights accrue to utility load, and are charged based on peak demand, regardless of how much generating capacity is designated to serve load. However, and this is undoubtedly central to PGE's implicit preference for the status quo, NITS cannot be used to support off-system sales of surplus power or resale of unused transmission capacity. In other words, switching from PTP to NITS could significantly reduce PGE's ability to discriminate against non-utility owned generation in its RFP processes.

b. The "Tipping Point" for PGE between PTP and NITS

PGE should use this IRP to outline the trade-off between ratepayers' savings by not using NITS with increased cost associated with less surplus PTP transmission to support off-system sales. At least some third party purchasers may have their own transmission rights. The IRP should also include an in-depth evaluation of how different transmission options impact PGE's preferred resource portfolio and renewable portfolio standard compliance costs and risks.

For many utilities, NITS would be higher cost than PTP because they are not as dependent on BPA to serve load as PGE. NITS is charged based on a utility's monthly peak load, which means that, for utilities with their own significant in-system generating assets, the cost of NITS is often too high relative to the share of the utility's load that otherwise require PTP transmission on a neighboring transmission providers' system.

PGE is different. It appears that the nominal breakeven point for PGE to consider converting to NITS service is about 3,750 MW of PTP transmission.[31] That is, the cost of NITS based upon PGE's actual 2015 peak loads is equivalent to the cost of about 3,750 MW of annual long-term firm PTP transmission on the BPA system. Until recently, PGE held less than 3,750 MW of PTP transmission rights on the BPA system. However, PGE's recent transmission purchases have increased PTP holdings to over 4,400 MW (and potentially much more) on BPA's system.

c. PGE's Reliance Upon PTP Transmission Unnecessarily Increases the Costs of Renewable Resources

PGE's IRP action plan calls for acquiring 515 MW of new renewable resources (nameplate capacity) and 775 MW of new dispatchable thermal capacity resources by 2021; or 1,290 MW of new incremental resources in total.[32] PGE describes that all of these resources will require new incremental PTP transmission capacity from BPA. The costs of this required incremental transmission has been added to the PVRR in PGE's Scenario analysis.[33] PGE assumes an added cost to PGE ratepayers of over $27 million/year by 2021 based on current BPA PTP transmission rates.[34] Given PGE's assumption of incremental BPA PTP transmission for each incremental resource, the relative cost effectiveness of different resource technologies will be skewed in the portfolio analysis. PTP transmission costs (which must be paid based on generator size rather than load) result in disparate impacts on different supply side resources

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31 3,750 MW x $1790 * 12 months = $80.5 million.

32 PGE's 2016 IRP at Appendix O: Portfolio Detail at 10.

33 PGE's 2016 IRP at 218 (including Sources and Assumptions for PGE Real Levelized Costs in Section 7.5.1)

34 1,290 MW x BPA PTP Rate ($1,790) * 12 months = $27.7 million.

because of varying annual capacity factors. For example, transmission for renewable resource options (with lower capacity factors) are considerably more costly relative to higher load factors thermal resources like PGE's so called "generic" capacity resource in preferred "Portfolio 3: Efficient Capacity 2021". Until the company provides information to the contrary, it appears that, if PGE were to convert its existing BPA transmission service to NITS, it could obtain any and all incremental future transmission service from BPA to the extent it is needed at no incremental cost. This conversion to NITS could significantly lower the costs of renewables, and make compliance with Oregon's newly aggressive renewable portfolio standard more cost effective.

d. PGE's Transmission Modeling Approach in the IRP Creates an Inherent Bias Against Shorter–term Contract Resources

The primary advantage of equitably considering shorter-term contract resources in the IRP analysis is to reflect the significant risk avoidance and technological obsolesce associated with deferring long-term fixed cost commitments. Under PGE's narrow-minded approach to modeling transmission, shorter-term contracts are assigned incremental fixed long-term transmission costs. And to add insult to injury, PGE's portfolio analysis extends those transmission costs for the length of the IRP planning period. This not only artificially increases the cost of short term resources relative to the lower cost treatment of transmission (e.g., NITS), it masks a portion of any net benefits of shorter term contract resources that would otherwise accrue to ratepayers.

e. PGE's 2009 IRP Transmission Plans

PGE has not always obscured its intentions for transmission planning. In the 2009 IRP, PGE's least cost transmission strategy was to build a new double circuit 500 kV transmission line from PGE's system near Salem, Oregon across the Cascades to Boardman site and on to the site of the company's Coyote Springs generating plant.[35] PGE justified this ambitious plan on the basis of near term transmission savings from de-contracting existing BPA PTP transmission it held for delivering Coyote Springs and Boardman generation to load. The Commission acknowledged the benefit of moving off BPA's PTP service and instructed the company to keep it informed.

PGE's resource and transmission planning since 2009, including in this IRP, are consistent with the Commission's policy guidance in the 2009 IRP and the associated Commission requirement that PGE return to the Commission with an updated analysis that shows sufficient net benefits to regarding whether the construction of the Cascade Crossing is prudent. PGE has pursued actions to improve how the economics of Cascade Crossing appear to the Commission:

1. Purchasing BPA transmission ahead of need;
2. Pursuing EFSC site certificates and air permits at the Boardman (Carty) site in advance of RFPs;
3. Designing their RFPs to favor PGE owned resources sited at the Boardman (Carty) site;
4. Pre-building certain transmission infrastructure to support Cascade Crossing (e.g., Grassland Switching Station); and
5. Extending the IRP planning period from 20 to 33 years.

While Cascade Crossing has dropped into the shadows, PGE never cancelled the project. Instead PGE "suspend[ed] permitting and development of the Cascade Crossing Project" and

[35] Order No 10-457 at 17.

recorded a $52 million before-tax write-off on its books.[36] At the same time, however, PGE requested deferred accounting treatment for the $52 million; although PGE withdrew its application, it remains to be seen whether PGE is still hoping to recover these costs in the future from PGE ratepayers.[37]

The re-emergence of Cascade Crossing as a transmission planning option in this IRP, even if only as a stalking horse, strongly suggests that the company needs to be more forthcoming with its perspective on other transmission options, such as a conversion from PTP to NITS on BPA's transmission system. If nothing else, the recent acquisition of costly new firm PTP transmission rights on BPA should be explained and equitable access to all potential sources of generation, utility or IPP owned made self-evident. In other words, the Commission should be made fully aware of what PGE's actual transmission plans are so that they can be properly reviewed, vetted, prior to an acknowledgement should that be forthcoming.

3. The Financial Context for this IRP Supports "Renting" Short-Term Resources Rather Than "Buying" New Long-Term Generation Resources to Meet PGE's Near Term Capacity Needs

The context for this IRP is unique in the level of uncertainty in scope of both the potential regulatory changes and technological advances, which should influence PGE's long-term planning. To begin with, gas prices remain abnormally low, which suggests price volatility ahead. Oregon's Legislature recently passed groundbreaking legislation to phase out coal and stimulate energy storage. Technological advancements have brought down the costs of renewable generation earlier than expected, which are increasingly competitive with non-

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36 Re Portland General Electric Request for Proposals for Capacity and Baseload Energy Resources, Docket No. UM 1535, Gray's Harbor Energy, LLC'S Request for Investigation at Attachment E (Aug. 5, 2013).

37 Re Portland General Electric Application for Deferral Accounting of Costs Associated with the Cascade Crossing Transmission Project, Docket No. UM 1656, PGE's Request to Withdraw Application for Deferral of Accounting Costs (Nov. 12, 2013).

renewable alternatives. Political uncertainty continues to build over future carbon costs. The region is struggling to establish an energy imbalance market ("EIM"), with the possibility of significant expansion of the California Independent System Operator in the medium term. And PGE itself is tied up in legal disputes over nearly $150 million in cost overruns at its Carty project.

This context naturally suggests that PGE should consider short-term contracts to meet its immediate needs, rather than lock itself and its captive ratepayers into large, long-term investments in generation. Yet, PGE's IRP concludes the opposite and doubles down on a late 20th Century approach to planning and resource acquisition that is ill-suited for the modern world. The Seventh Power Plan concludes "[s]pot market prices for wholesale power continue to be low, due to increasing penetration of renewable resources with low variable operating costs and low natural gas prices, and do not provide an accurate representation of the avoided cost of new resources." So why isn't PGE clamoring to "rent" resources?

PGE needs to own up to the fact that utilities are not that great at analyzing long-term risk, and especially against efficiency and demand response projections. The Commission should require PGE to take a hard look at shorter-term options, at least for the duration of its current IRP Action Plan. As examples of early plant closures and cost overruns continue to pile up, it seems incomprehensible to allow PGE to stay the traditional "big build" course without at least requiring a thorough comparison between short-term contracts and long-term investments.

The region's expectation of yesteryear that nuclear power could be "too cheap to meter" provides an important lesson worth revisiting in today's context. In the 1970s, PGE, along with Puget Sound Energy ("PSE") (as Puget Sound Power & Light), Avista (as Washington Water Power), and Washington Public Power Supply Systems ("WPPSS") all believed sizeable commitments to nuclear plants were prudent and in the public interest. PGE's controversial Trojan plant was closed early for economic reasons. PSE, PGE, PacifiCorp, and Avista also abandoned the Pebble Springs and Skagit plants. And although five WPPSS nuclear plants were planned in the 1970s, only one was completed at a cost far more expensive than expected. WPPSS ultimately lapsed into what was then the nation's largest municipal bond default.[38] In hindsight, it is easy to see that the expectations for long-term nuclear investments did not pan out well for the region. Yet, unfortunately for ratepayers, investor owned utilities were still allowed to recover nearly all of the costs of these abandoned, closed and expensive nuclear power plants.[39]

Hindsight is twenty-twenty, but with hindsight it is clear PGE fared better, but still failed to accurately predict long-term regulatory requirements, operational risks, and long –term closure expenses with its thermal resources. For example, PGE started its Boardman coal plant before the passage of the 1977 Clean Air Act amendments, and hoped to avoid the significant new environmental obligations that would be imposed upon new sources of pollution. Eventually, however, PGE agreed to close the Boardman plant early in 2020 because early closure would save ratepayers about $470 million. PGE should incorporate its analysis of lessons

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38 David Wilma, Washington Public Power Supply System (WPPSS), HISTORYLINK.ORG http://www.historylink.org/File/5482; Daniel Pope, A Northwest Distaste for Nuclear Power, THE SEATTLE TIMES (July 31, 2008), http://www.seattletimes.com/opinion/a-northwest-distaste-for-nuclear-power/.

39 E.g., People's Org. for Wash. Energy Res. v. WUTC, 104 Wash.2d 798, 804 (Wash. 1985) ("the WUTC allowed Puget Power to ultimately recover, through rates, $47.5 million rather than Puget Power's full $53.5 million net investment [in Pebble Springs]. The part of the rate increase attributable to Pebble Springs increased the average residential customer's monthly billing by $1.12."); Gearhart v. Pub. Util. Comm'n. of Or., 339 P.3d 904, 356 Or., 216 (Or. 2014) (the OPUC allowed a return of, but not a return on Trojan's costs and PGE's capital investment).

learned before it decides to move forward with its long-term resource investment strategy in the context detailed above.

4. The IRP Fails to Analyze Short-Term Options to Meet PGE's Near-Term Needs

NIPPC agrees that PGE appears to have a short-term resource need, but submits that PGE has not adequately analyzed short-term opportunities to address that need. PGE's IRP focuses exclusively on long-term forecasts and solutions and does not consider how short-term and medium-term solutions could solve its needs for a period of time. Moreover, PGE's long-term market availability forecasts appear to be artificially constrained, which in turn inflates PGE's long-term needs. Because PGE may have forecasted an inflated long-term need, PGE must consider how potential short-term options impact those needs before moving forward with its plan to make a long-term investment in a gas plant in 2021.

The very limited consideration of hydro contracts in the IRP illustrates this problem. PGE's IRP describes hydro availability as one of the "key variables" in its scoring metrics that allows PGE to identify a Preferred Portfolio[40] and also includes hydro availability among its environmental considerations.[41] Yet, PGE has not even explained the availability of its own existing three hydro contracts that are up for renewal.[42] And despite acknowledging the benefits of providing "clean, carbon-free energy to customers" and shortcomings in reaching its long-term environmental goals, PGE's IRP mainly focuses on risks associated with hydro. PGE contends that contract expiration and uncertain hydro conditions, due to climate change, make

[40] PGE's 2016 IRP at 30.

[41] Id. at 87.

[42] The Commissioners directed PGE to update them on any progress renewing its expiring hydro contracts (noting that despite PGE's active negotiations, this capacity is not reflected anywhere in the IRP) and to include any additional hydro availability identified. PGE Presentation, at 44:00 (Dec. 20, 2016).

hydro contracts problematic.[43] These may be legitimate long-term risks associated with climate change and hydro contracts, but none that should not preclude PGE from analyzing the availability of short-term hydro contracts, which are widely believed to be available.

The IRP does not adequately analyze the market availability of hydro contracts, or even consider how entering into new hydro contracts (either by renewing its existing contracts, or entering into new agreements) would affect its needs. In addition to hydro, other short term contracts should be considered. PGE could "rent" capacity from a gas plant with a shorter term PPA rather than buy a gas plant. PGE's lack of analysis on short-term and medium-term energy contracts begs the question as to what other kinds of short-term options may be available to PGE. Other short-term solutions, like energy efficiency or demand response, could also serve PGE's near term need and should be analyzed more rigorously. The absence of this kind of analysis is a glaring problem that PGE should address before moving forward with its current action plan.

5. The IRP Artificially Constrains Market Availability

The problem with the IRP's lack of short-term analysis is exacerbated by PGE's assumptions on market availability. PGE's IRP appears to artificially constrain market availability, which helps to justify the option of building a new gas plant. For example, PGE's IRP assumes only 200 MW to be available in the spot market.[44] To begin with, NIPPC contends this number is far too low and is not supported by PGE.[45] Worse yet, that 200 MW cap stays flat through 2041, despite PGE's steadily increasing load forecast.[46] This divergence is flawed. And

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43 PGE's 2016 IRP at 87.

44 PGE's 2016 IRP at 118.

45 During a public presentation before the Commission, PGE admitted that it used 200 MW based on "historical context" which it explained is simply copied from previous IRPs). PGE Presentation, at 39:10 (Dec. 20, 2016).

46 PGE's 2016 IRP at 115 (estimating PGE's annual capacity need in Figure 5-1).

this flawed divergence signals a long-term need, which leads PGE to ultimately conclude it should build another gas plant.

Comparing PGE's extended "cap" on market availability to the assumptions of other utilities in the region demonstrates additional analysis offers a stark contrast. While PSE and PacifiCorp have been experiencing an energy surplus for "over a decade" and relying heavily on market purchases in their IRPs, PGE has been assuming only 200 MW of market availability per year indefinitely. PacifiCorp's 2015 IRP determined that market purchases provided the least cost and risk plan to meet its near term resource needs.[47] Likewise, PSE's 2015 IRP concluded the region has long enjoyed an energy surplus. "For a decade, these surpluses have enabled many utilities, including PSE, to use wholesale market purchases to meet load obligations with a high degree of confidence in the reliability of both physical supply and reasonably prices."[48] PSE continues, by explaining the region's energy surplus, "has made it less expensive for utilities like [PSE] to meet its load needs by purchasing energy and capacity in the wholesale market rather than building new generation plants."[49]

As briefly noted above, the Commission identified this disconnect as a problem in PGE's 2013 IRP, (which ultimately concluded no new major resources were needed during the Action Plan) and expressly directed PGE to consider "[m]aintaining an open position (e.g., buying spot or short-term electricity)" in its next IRP cycle.[50] The Commission explained,

> We also share the concerns raised about PGE's IRP portfolio modeling. For its next IRP planning cycle, we direct PGE to hold a series of workshops with stakeholders (with at least one attended by the Commissioners) to develop a wide range of multiple portfolios for meeting its incremental capacity and energy needs.

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47 PacifiCorp's 2015 IRP at 2.
48 PSE's 2015 IRP at G-4.
49 Id. at G-1.
50 Order 14-415 at 5-6

The Commission suggested PGE consider portfolios that increase renewable generation with costs comparable to natural gas and accelerate programs in energy efficiency, demand response, distributed generation, and storage.[51] Despite clear direction from the Commission, it appears the PGE has failed to address its "incremental capacity and energy needs" and extended the IRP horizon and focused on longer-term goals instead.

6. The IRP Does Not Evaluate PGE's Options or Explain PGE's Strategy on Gas Storage

The IRP mentions, almost in passing, that PGE has entered into a precedent agreement with NW Natural to double PGE's storage volume rights at NW Natural's Mist Storage Facility.[52] The IRP does not, however, include any analysis comparing increased firm gas storage with other alternatives. PGE's gas and storage strategy should be explained and analyzed in the IRP rather than determined unilaterally.

PGE's current gas storage contract, which expires in 2017, is being replaced by a commitment for "firm storage at NW Natural's North Mist Expansion project located north of the Mist Storage Facility." And the new agreement, "will provide PGE approximately twice the storage volume the Company currently has at Mist as well as No-Notice Service."[53] Although the IRP outlines PGE's rights under the new agreement, there is nothing that explains why PGE decided to enter into the precedent agreement with NW Natural, and nothing that allows stakeholders to analyze costs, risks and benefits to ratepayers.

The lack of information regarding gas storage troubles NIPPC, because in 2009 PGE determined such gas storage was an indispensable part of its acquisition strategy without

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51 Id.

52 PGE's 2016 IRP at 83. Id.

53 Id. No-Notice Service allows PGE to receive gas on demand, without making prior nominations, without paying balancing and scheduling penalties.

indicating as much in either its 2009 IRP or RFP.[54] NIPPC argued that PGE should not be permitted to use gas storage to disqualify bidders.[55] PGE countered that it did not have any excess gas storage that it could make available to bidders, and should not be required to do so.[56] Ultimately the Commission permitted PGE to condition RFP participation upon a showing that bidders had the ability to acquire gas storage and intraday scheduling.[57] NIPPC believes the 2016 IRP suggests that PGE may again attempt to use gas storage to disqualify RFP bids. NIPPC notes, however, that PGE's expanded storage rights should not support similar treatment in its next RFP, especially given the paucity of analysis regarding the cost, risks and benefits.

7. The IRP Exaggerates the Benefits, Downplays the Risks of Utility Ownership, and Does Not Properly Credit the Unique Benefits of PPAs

The overall theme of PGE's IRP (i.e., utility ownership is great and PPAs are awful) is misguided and does not speak to the reality of today's energy market, as evidenced by PSE and PacifiCorp's IRPs. Although PGE's IRP claims to be "generally agnostic with respect to ownership structure", it inflates the benefits, and ignores the risks, of utility ownership.[58] Likewise, the IRP strains to detail every possible, theoretical risk associated with signing a PPA, and then completely ignores the unique benefits PPAs offer. A general bias for self-generation project, which is inherent in the utility model, may explain PGE's natural preference for utility ownership, but it does not excuse the inadequate analysis or the unseemly conclusions in this IRP.

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54 See Re Portland General Electric Company Request for Proposals for Capacity Resources, Docket No, UM 1535, Order No. 11-371 at 3-4 (Sept. 27, 2011).
55 Order No. 11-371 at 3.
56 Id. at 4.
57 Id.
58 PGE's 2016 IRP at 222-26.

f. Exaggerated "Benefits" of Utility Ownership and "Risks" of PPAs

The following PGE's statement concisely encapsulates the problems with this IRP:

> Through experience developing, owning, and operating facilities, PGE has demonstrated its ability to mitigate the risks and manage the costs of resource ownership across all technologies and fuel types, and across multiple projects of significant size, scope, and complexity.[59]

PGE's bravado about its experience in utility-owned generations is unfounded, given its history of early-plant closures, its deferral of $50 million in Cascade Crossing costs, and its recent request to defer nearly $150 million in cost overruns at its Carty generation project.[60] PGE touts that the ownership model allows it use existing locations and infrastructure, but there is nothing stopping PGE from allowing third-party developers to use PGE's location and infrastructure, which are ultimately paid for by ratepayers. Likewise, PGE suggests that a utility-backed PPA may be the only way an independent power producer can secure financing, because the utility's "strong credit" is backing the agreement. But, isn't it the nearly-guaranteed ratepayer recovery that permits utilities themselves to secure financing? Overall, the benefits of utility ownership in PGE's IRP conflate the benefits or receiving of nearly-guaranteed ratepayer funds with that of the utility's own expertise.

The IRP includes only one half of one page, including three bullet points and two paragraphs in total, on the risks associated with utility ownership. The three bullet points provides the entire list of risks PGE identified as being associated with utility ownership, and do not include construction defects (like Trojan), regulatory changes (like Boardman), expensive

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59 Id. at 223.

60 Re Application of Portland General Electric Company for an Order Approving the Deferral or Incremental Revenue Requirement Associated with the Carty Generating Station, Docket No. UM 1791, Application for Deferral at 1 (July 29, 2016).

capital repairs (like Boardman in 2005), or cost overruns (like Carty).[61] Instead of actually outlining the real risks of ownership, PGE uses this minimal discussion to explain how it can mitigate the identified utility ownership risks, and then fallaciously explains how these risks are actually minimized with utility ownership and increase with PPA options.

Moreover, the IRP's analysis on the cost of credit within this section is either misplaced or misguided. The IRP claims that "PPAs reduce PGE's financial flexibility or increase the Company's borrowing costs." The discussion of imputed debt associated with PPAs is flawed, because have less of an impact on PGE's financial flexibility or borrowing costs than borrowing money to finance a utility project. The Commission has repeatedly declined to endorse or address the utility's concerns with imputed debt.[62] Likewise, PGE's statements about margin requirements have nothing to do with the cost of credit. PGE's IRP concedes that margin requirements protect both buyers and sellers from default due to drastic changes in market

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61 Application to Amortize the Boardman Deferral, Docket No. UE 196, Order No. 10-051 at 1 (Feb. 11, 2010); PGE's 2016 IRP at 224 (identifying only three risks associated with utility owned generation: 1) costs of ownership and operation exceeding market prices; 2) costs of poor performance and early retirement; and 3) unknown liabilities due to reclamation at the end of project life in its Risks Associated with Utility Ownership section).

62 Re Commission Investigation Regrading Competitive Bidding, Docket No. UM 1182, Order No. 13-204 at 11 (June 10, 2013) (concluding "risk" from IPP bids "is already addressed sufficiently in the RFP process and that no changes to the [IRP] Guidline 10(d) evaluation process are required."); Re Commission Investigation Regarding Performance-Based Ratemaking Mechanisms to Address Potential Build-vs-Buy Bias, Docket No. UM 1276, Order No. 11-001 at 6 (Jan. 3, 2011) (finding debt imputation "more appropriately addressed in the context of an overall examination of a utility's cost of capital"); Re Commission Investigation Relating to Electric Utility Purchases from Qualifying Facilities, Docket No. UM 1129, Order No. 07-360 at 28 (Aug. 20, 2007) (determining that debt imputation was "not likely to be caused by large QF contracts" and that "imputed debt associated with QF power purchase agreements should not be taken into account in determining avoided costs"); Re Investigation Regarding Competitive Bidding, Docket No. UM 1182, Order No. 06-446 at 11 (Aug. 10, 2006) (the Commission may require the utility to obtain an advisory opinion from a ratings agency to substantiate the utility's debt imputation analysis).

prices.[63] So, it is hard to understand why PGE would include margin requirements among the "benefits" or utility ownership and "risks" associated with PPAs.

Finally, PGE's IRP suggests that at the end of a PPA, PGE will be forced to find a replacement contract among only less-comparable resources.[64] This assumes that independent power producers, with existing projects in prime generation sites, do not want to continue to sell power to PGE or that the market will otherwise fail. NIPPC is willing to concede that this is possible, but notes that it seems very improbable and the only reason the market will fail is if the utilities succeed it killing it. So improbable, in fact, that statements like these seem out of place in what should be a document analyzing long-term resource acquisition options. Asserting there are risks, and lost benefits, due to contract expiration is fundamentally flawed because it ignores the fact that contracts are frequently renewed. Contract renewals actually provide additional benefits to PGE, which were unsurprisingly not mentioned in the IRP.

PGE's IRP includes contract default as another "risk" to PPAs, pointing to PGE's exposure to unknown contract costs due to abandonment or default.[65] But, this representation is also flawed because contractual damages are actually quite certain, because they are spelled out in the contract, as opposed to, for example, the costs due to failed utility build or plant failure, including early closure. Compare the risks to ratepayers of Carty's contract default ($150 million plus interest) with the risks to ratepayers if Carty had been a third party PPA (legal fees and some administrative costs).

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63 PGE's IRP at 223.

64 Id. ("If a utility purchased power from an IPP, who owned one or more of these prime sites, and the IPP did not want to extend the agreement upon expiration or sell the resource to the utility, the utility would have to seek out another resource.")

65 Id. at 225.

g. Actual Risks of Utility Ownership

Construction overruns provides perhaps the most obvious, and recent, example of risks associated with utility ownership. PGE's ill-fated Carty Generating Station 1 is the elephant PGE cannot get out of the room as it discusses its long-term planning needs. The reason is that, despite significant opposition from industrial customers and independent power producers, PGE selected a utility-owned bid over what customers and other bidders argued were lower cost and lower risk bids offered by independent power producers.[66] And despite the lofty $514 million original estimate, it now appears that Carty's capital costs will be anywhere from $126 to $146 million more than originally expected.[67] Ratepayers, who may be on the hook for an additional $150 million in cost overruns, could have realized nearly-unprecedented savings had PGE simply selected a lower-cost and less risky PPA rather than opting to build Carty.

PSE's Lower Snake River wind project offers another example where long-term investment in utility ownership proved unnecessarily expensive for the region's ratepayers. PSE began permitting and planning on the Lower Snake River project well in advance of its need, on a site that allowed for four wind resource areas, and included enough acreage and wind potential for up to 1432 MW of development.[68] Once an additional project is established, these type of

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66 Ted Sickinger, Despite acrimony and accusations, PGE's bid process doesn't need investigating, regulators decide, THE OREGONIAN (Sep. 20, 2013), http://www.oregonlive.com/business/index.ssf/2013/09/explanation_of_portland_genera.html; Ted Sickinger, Construction halts at PGE's new gas plant in Boardman, THE OREGONIAN (Dec. 17, 2015), http://www.oregonlive.com/business/index.ssf/2015/12/construction_halts_at_pges_new.html.

67 Re PGE Application for Deferral of Incremental Revenue Requirement Associated with the Carty Generating Station, Docket No. UM 1791, PGE Application at 2 (July 29, 2016).

68 WUTC v. PSE, WUTC Docket Nos. UE-111048 and UG-111049 (consolidated), Order No. 08 at ¶ 378 (May 7, 2012); Re CUP 012609 Lower Snake River Wind Energy

multi-phase project sites allow utilities to out-compete independent power producers bidding against utility-owned projects in subsequent RFPs, based on siting and transmission savings.[69] Washington's ratepayer advocates (Public Counsel) and industrial customers argued that even the initial phase of the Lower Snake River project was not needed, not prudent, not cost-effective, and not used or useful. The Washington Utilities and Transportation Commission ("Washington Commission") staff raised additional concerns over PSE's inflated power costs, incentive pay, and federal income tax implications associated with the project.[70] Although the Washington Commission agreed Lower Snake River was built in advance of need, it determined that PSE's $770 million investment was prudent in light of PSE's future RPS obligations.[71] Had PSE opted to purchase shorter-term contracts to meet its short-term need, ratepayers could have either completely avoided shouldering that $770 million investment, or at the very least taken advantage of today's lower prices. Lower Snake River demonstrates the risks to ratepayers associated with utility owned generation projects, and the powerful incentives to justify utility ownership ahead of need.

By way of comparison, Avista's Palouse Wind PPA example illustrates the stark difference between "renting" and "buying" generation resources. In 2012, the Washington

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Project, Hearing Examiner Decision (Nov. 25, 2009) available at: http://www.co.garfield.wa.us/planning/lower-snake-river-project.

69 Because PSE built ahead of need, Phase II of Lower Snake River was sold to PGE, as the lower Tucannon 267 MW wind project. Re PGE Request for General Rate Revision, Docket No. UE 283, Order No. 14-422 at 8 (Dec. 4, 2014); Re PGE Renewable Resources Automatic Adjustment Clause, Docket No. UE 288, Order No. 15-129 at 3 (Apr. 15, 2015). (costing PGE's ratepayers approximately $525 million).

70 Id. at ¶¶ 300-329. The Commission received 778 public comments on PSE's rate increase proposal—733 opposed, three in favor, and 42 undecided.

71 Id. at ¶¶ 411, 418.

Commission also approved as prudent Avista's 30-year PPA with Palouse Wind.[72] Palouse Wind's $62 per MWh bid was selected from Avista's RFP to build a 58 turbine project generating 104 MW in Whitman County. Unlike PSE's Lower Snake River 1 and PGE's Tucannanon, any Palouse Wind cost overruns could not be collected from ratepayers. Comparing PSE's contemporaneous cost-plus $70 per MWh price with Avistas's fixed price $62 per MWh price makes clear that PPAs can offer significant long-term savings to ratepayers.[73]

While the Palouse PPA offered Avista's ratepayers significant long-term savings, it may simply illustrate the prudency offered to the utility by hindsight. The Palouse PPA decision closely followed Avista's decisions to construct, delay, and ultimately abandon its Reardan Wind Project. Avista had planned to have Reardan operating in time to qualify for federal and state tax credits, but announced a series of delays as it attempted to make its costs pencil out. At the second such delay, Avista indicated that the electricity would not be needed for several more years. Hugh Imhof, a spokesperson for the utility stated, "[w]e thought it would be more prudent to wait until we need the electricity, or the renewable energy credits, and do it then."[74] Four years after the Reardan project commenced, but, luckily for ratepayers, before construction started, Avista reevaluated the estimated costs of the project and abandoned Reardan. The

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72 WUTC v. Avista, WUTC Dockets Nos. UE-120436 and UG-120437 (consolidated), Order No. 09 at ¶¶ 87-329 (Dec. 26, 2012).

73 Avista 2013 IRP at 2-30, A-24; BUSINESS WIRE, First Wind Secures $210 Million Financing for Palouse Wind Project (Dec. 19, 2011) available at: http://www.businesswire.com/news/home/20111219005194/en/Wind-Secures-210-Million-Financing-Palouse-Wind.

74 Becky Kramer, Avista pushes back Reardan wind farm construction, THE SPOKESMAN-REVIEW (Feb. 17, 2010) available at http://www.spokesman.com/stories/2010/feb/17/avista-pushes-back-reardan-wind-farm/.

Commission ultimately authorized Avista to recover its share, about $2.5 million from customers for the ill-timed project.[75]

PacifiCorp has its own set of similar decisions that have proved costly to its ratepayers. In 2008, the Commission determined PacifiCorp's Rolling Hills project acquisition was not prudent, due to its poor capacity factor.[76] That order also acknowledged PacifiCorp's strategy for avoiding the Commission's competitive bidding guidelines, implemented to counter the utility bias for self-generation projects. PacifiCorp has also been found to have imprudently installed costly upgrades at its coal plants, which resulted in cost increases for its ratepayers.[77] And PacifiCorp's outage at its Hunter plant in 2000 cost Oregon ratepayers more than $130 million in power costs, plus the utility's legal and other fees to litigate the case all the way to the Oregon Court of Appeals.[78]

NIPPC notes that some cost overruns and risks associated with utility-owned generation do not necessarily stem from poor decision-making or the utility's bias for ownership, but merely from the utility model. For example, Idaho Power requested $14 million in cost overruns when a

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75 Re Petition of Avista for an Accounting Order Authorizing Accounting Treatment, WUTC Docket No. UE-130536, Order 01 at 2 (May 17, 2013).

76 Re PacifiCorp, dba Pacific Power, 2009 Renewable Adjustment Clause Schedule 202, WUTC Docket No. UE 200, Order No. 08-548 at 19-20 (Nov. 14, 2008); see also Re NIPPC Petition for an Investigation Regarding Competitive Bidding, Docket No. UM 1182, NIPPC's Direct Testimony and Exhibits of William A. Monsen, NIPPC/100, Monsen/30-33 (Nov. 16, 2012).

77 WUTC v. Pacific Power & Light Co., a division of PacifiCorp, WUTC Docket No. UE-152253, Order No. 08 at ¶ 116 (PacifiCorp "failed to meet its burden to demonstrate the prudence of its decision to install the SCR systems on Bridger Units 3 and 4."); Re PacifiCorp dba Pacific Power, Request for a General Rate Revision, Docket No. UE 246, Order No. 12-493 at 27-32 (Dec. 30, 2012).

78 Indus. Customers of N.W. Utils. v. Pub. Util. Comm'n of Or., 196 Or. App. 46 (Or. App. 2004).

latent construction defect manifested itself after commercial operation commenced.[79] According to Idaho Power, a contractor engaged at the utility-owned site failed to install the bolts in the gas turbine's air inlet plenum in accordance with construction specifications.[80] The developer of the build-to-own transfer project, and apparently Idaho Power, failed to detect the improper installation and a bolt ultimately dislodged, was ingested in the turbine, and caused extensive internal damage. These types of events are not uncommon at power plants, but only in the case of utility-owned plant are the ratepayers at risk for the costs overruns, increased insurance premiums, and other consequences of such events.

As these construction risks demonstrate, cost recovery for utility-owned generation creates price uncertainty for generation facilities where the risk is borne by ratepayers rather than by those taking the risk or responsible for managing the risk. The same problem extends to operational risks. Traditional utilities have relative inexperience in developing and operating large renewable plants, and substantial operating risks can decrease profitability. This is especially true when considering the fact that most of the very best sites have already been developed. PPAs can enhance operational reliability, because independent power producers, unlike utilities, must meet operational targets to remain profitable and stay in business.

Finally, as technology improvements continue to rapidly reduce prices, utilities must weigh the benefits of building today against the savings associated with waiting for technology

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79 Re NIPPC Petition for an Investigation Regarding Competitive Bidding, Docket No. UM 1182, NIPPC's Direct Testimony and Exhibits of William A. Monsen, NIPPC/100, Monsen/19-20 (Nov. 16, 2012) (discussing the same latent defect among a host of other cost overruns at utility-owned plants).

80 Re Idaho Power Co.'s Application for a Certificate of Public Convenience and Necessity for the Langley Gulch Power Plant, Idaho PUC Case No. IPC-E-09-03, Rebuttal Testimony of Vernon Porter at 4 (July 14, 2009), available at: http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE0903/company/20090702PORTER%20REBUTTAL.PDF.

improvements to drive costs down further. In the modern market, technology risks are not limited to latent defects or theoretical design improvements. PGE's Trojan Nuclear Power plant, mentioned in brief above, provides a cautionary tale in technology risk. When Trojan came online in 1976, it was the largest nuclear plant in the county and cost $460 million to build.[81] It was Oregon's only nuclear plant and there was public, environmental opposition to the plant form its inception.[82] Trojan was on line only sixteen years before PGE decided to decommission the plant.[83] Although designed to last the life of the plant, after only four years, the steam-generator tubing began cracking. PGE estimated the decommissioning costs would reach $404 million.[84] In short, PGE's investment in Trojan was a disaster. Thus, PGE should consider whether PGE's rush to build a new gas plant, especially amid public, environmental opposition, repeats the same flawed decision making.

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81 Re Application of PGE for an Investigation into Least Cost Plan Plant Retirement, Revised Tariffs Schedules for Electric Service in Oregon Filed by PGE, PGE's Application for an Accounting Order and for Order Approving Tariff Sheets Implementing Rate Reduction, Docket Nos. DR 10, UE 88 & UM 989, Order No. 08-487 (Sept. 30, 2008); see also George Rede, The basics on nuclear power and Trojan, THE OREGONIAN/OREGONLIVE (Aug. 30, 2008), http://www.oregonlive.com/opinion/index.ssf/2008/08/the_basics_on_nuclear_power_an.html.

82 In 1977 and 1978 protests at the plant resulted in hundreds of arrests. In 1992, PGE spent $4.5 million to defeat a ballot measure seeking to close the Trojan plant.

83 Re Application of PGE for an Investigation into Least Cost Plan Plant Retirement, Revised Tariffs Schedules for Electric Service in Oregon Filed by PGE, PGE's Application for an Accounting Order and for Order Approving Tariff Sheets Implementing Rate Reduction, Docket Nos. DR 10, UE 88 & UM 989, Order No. 08-487 at n. 58 (Sept. 30, 2008).

84 Re Revised Tariff Schedules for Electric Service in Oregon filed by PGE, Docket No. UE 88, Order No. 95-322 at 3 (Mar. 29, 1995); PGE Form 10-Q, SECURITIES AND EXCHANGE COMMISSION (Mar. 31, 1997); George Rede, The basics on nuclear power and Trojan, THE OREGONIAN/OREGONLIVE (Aug. 30, 2008), http://www.oregonlive.com/opinion/index.ssf/2008/08/the_basics_on_nuclear_power_an.html.

h. Actual Benefits of PPAs

Diverse ownership of generation provides unique benefits to customers that were not included in PGE's IRP. To begin with, competitive markets drive down costs, which produces significant savings for ratepayers. Historically, healthy competition has driven down generation costs for all types of ownership. And non-utility ownership provides other savings opportunities to customers. First, the utility model itself effectively provides for a surcharge on the costs of generation projects. Second, PPA shareholders, rather than captive ratepayers, shoulder the risks associated with development, operation, and management of generation.

PPAs also reduce the risks historically associated with utility ownership, including those detailed above. Purchasing power through a PPA minimizes the capital demands on traditional utilities, which in turn helps improve the utilities balance sheets. Renewable development especially, which may seem fairly new, or fast-paced to traditional utility businesses, naturally aligns with either a short or long term "rental" contract rather than investing in a long-term utility-owned project.

Finally, PPAs are uniquely positioned to manage environmental, regulatory risk in today's changing political climate. Whether carbon costs are implemented immediately under current federal regulations, or are implemented later, there seems to be little doubt that some kind of carbon limitation will be necessary to meet our global climate change goals. Thus, new long term utility investments in carbon burning facilities brings with it a lot of environmental concerns that can largely be avoided, simply by purchasing power from independent power producers.

III. CONCLUSION

For the reasons detailed above, NIPPC recommends the Commission not acknowledge the IRP, without requiring additional analysis by PGE.

RESPECTFULLY SUBMITTED this 24th day of January, 2017.

Sidney Villanueva

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Of Attorneys for Northwest and
Intermountain Power Producers Coalition

Attachment A

January 19, 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. 030
Dated January 5, 2017

Request:

Please refer to Table 5-3: Renewable resource portfolios examined in the REFLEX study:

A. Please confirm or deny that the new thermal resource portfolios that PGE evaluated using REFLEX for IRP Portfolio A (25% RPS – Gorge Wind) include both a case adding 200 MW of Frame CTs and a case adding 200 MW of Reciprocating Engines.
B. If the answer is confirm, please provide a summary of results comparing the case adding Frame CTs to the case adding Reciprocating engines.

Response:

PGE can neither confirm nor deny the request as asked.The REFLEX analysis was performed prior to portfolio construction, so Portfolio A does not correspond to a specific IRP Portfolio. PGE confirms that among the portfolios tested by E3 with REFLEX was a portfolio that combined the REFLEX renewable Portfolio A with a 200 MW frame CT and a portfolio that combined the REFLEX renewable Portfolio A with 11 reciprocating engines, each sized at 18.2 MW, totaling 200 MW.

A. The REFLEX output summaries are included in the following table for the 200 MW Frame CT and 200 MW Reciprocating Engine portfolios associated with REFLEX Renewable Portfolio A.

REFLEX Renewable Portfolio	A	A
Thermal Additions	200 MW Frame	200 MW Reciprocating Engines
Maximum Hour-Ahead Imbalance (MW)	603	581
Annual Hour-Ahead Imbalance (MWh)	19,078	18,772
Frequency of Non-Zero Hour-Ahead Imbalance (%)	1.66%	1.64%
Maximum Real-Time Imbalance (MW)	311	311
Annual Real-Time Imbalance (MWh)	506	509
Frequency of Non-Zero Real-Time Imbalance (%)	0.23%	0.23%
Maximum Renewable Curtailment (MW)	895	895
Annual Renewable Curtailment (MWh)	138,667	131,907
Frequency of Non-Zero Renewable Curtailment (%)	7.48%	7.22%

B. Not applicable

January 19, 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. 031
Dated January 5, 2017

Request:

Please confirm or deny that PGE did not perform any capacity analysis using REFLEX that evaluated the addition of reciprocating engines to Portfolio B:

A. If the answer is confirm, please explain why PGE did not do a comparative evaluation of flexible capacity across capacity technologies when evaluating Scenarios that included the integration of solar resources as well as wind resources.
B. If the answer is deny, please provide a summary of REFLEX results and associated insights gained when comparing the flexible capacity characteristics of the Frame CTs compared to the reciprocating engines in Portfolios that included solar resource additions.

Response:

PGE confirms that E3 did not evaluate Renewable Portfolio B with the addition of reciprocating engines in REFLEX.

A. The REFLEX results from Portfolio A suggested that the addition of equivalent capacities of frame CTs and reciprocating engines had similar impacts to the observed hour-ahead and real-time imbalances. E3 did not perform tests of all thermal addition options for Renewable Portfolio B in in part because of this observation and because the computationally intensive nature of the REFLEX analysis required prioritization of model runs. PGE prioritized investigating the flexibility challenges at increased renewable penetrations and requested that E3 create and run the 50% RPS Portfolio. Both incremental wind and solar resources were incorporated into the 50% RPS

Portfolio, which was tested with 200 MW of reciprocating engines and a 200 MW frame CT.

The REFLEX output summaries are included in the table below for the 200 MW Frame CT and 200 MW Reciprocating Engine portfolios associated with the 50% RPS REFLEX Renewable Portfolio.

REFLEX Renewable Portfolio	50% Portfolio	50% Portfolio
Thermal Additions	200 MW Frame	200 MW Reciprocating Engines
Maximum Hour-Ahead Imbalance (MW)	629	615
Annual Hour-Ahead Imbalance (MWh)	13,089	12,456
Frequency of Non-Zero Hour-Ahead Imbalance (%)	1.0%	1.0%
Maximum Real-Time Imbalance (MW)	289	299
Annual Real-Time Imbalance (MWh)	1,134	970
Frequency of Non-Zero Real-Time Imbalance (%)	0.28%	0.26%
Maximum Renewable Curtailment (MW)	2,176	2,176
Annual Renewable Curtailment (MWh)	1,641,225	1,613,564
Frequency of Non-Zero Renewable Curtailment (%)	28.3%	27.9%

B. Not applicable.

January 11, 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. 002
Dated December 28, 2016

Request:

Refer to PGE's Characterization of Supply Side Resources (Appendix K), please explain why PGE directed Black and Veatch to assume all generic capacity resources selected for study were "add-on units to existing PGE combined cycle or thermal plant sites", when preparing cost and performance estimates for use in analytical modeling support for the IRP.

Response:

PGE did not direct Black and Veatch (B&V) to assume all generic capacity resources selected for study were "add-on units to existing PGE combined cycle or thermal plant sites." For the purpose of analysis in the 2016 IRP, PGE and B&V elected to model the generic resource costs of the following simple cycle options:

- 1x0 GE LMS100,
- 1x0 GE 7F.05, and
- 6x0 Wärtsilä 18V50SG

B&V's description of the general site assumptions is too narrow. The generic resource costs for the simple cycle options are modeled generally as add-on units i.e., there is no specific PGE site assigned to the assumptions.