BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

LC 66

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY, 2016 Integrated Resource Plan	**SIERRA CLUB COMMENTS [PUBLIC VERSION]**

Sierra Club submits the following initial comments on Portland General Electric's 2016 Integrated Resource Plan (IRP). These comments were prepared with technical assistance from Tyler Comings, Dr. Ariel Horowitz, and Kenji Takahashi of Synapse Energy Economics, Inc. As with other Oregon IRP processes Sierra Club has participated in, we focus on the overarching goal of achieving transparent resource planning that strikes a balance between low costs and risk mitigation. While we appreciate Portland General Electric's (PGE) efforts towards stakeholder involvement, we find that the IRP as presented proposes a vague and alarming plan based on significant methodological weaknesses.

We are concerned that PGE has a specific plan to build a new natural gas combined-cycle (NGCC) plant using this IRP as justification, despite the fact that it claims to have not arrived at any specific resource decisions. This is troubling for two reasons: 1) PGE has failed to propose a clear resource decision in this IRP, presenting instead an action plan that includes acquisition of a large amount of "generic," "efficient," "dispatchable" capacity of an uncertain resource type, denying the Commission necessary oversight; and, 2) PGE has failed to justify its preferred portfolio which includes construction of an "efficient capacity" resource with the costs, performance, and emissions profile of an NGCC unit. This leads to our concern that PGE intends to construct such a unit but has not fully disclosed its intentions to the Commission or stakeholders.

I. Summary of PGE's IRP Analysis

Sierra Club evaluated the analysis conducted by PGE in its 2016 IRP. We looked in-depth at PGE's underlying assumptions, modeling structure, and its evaluation of resource options.

In its 2016 IRP, PGE developed 21 portfolios of energy resources, including new natural gas generation, demand-side actions, and renewable energy. PGE also modeled two types of unspecified resource additions: "generic capacity," which was modeled as a simple-cycle, natural gas-fired combustion turbine (CT), and "efficient capacity," assumed to have the costs and operational characteristics of a natural gas-fired combined cycle (CC) unit. PGE asserts that these generic additions are meant to represent any resource type, or combination of resource types, that can provide similar cost and performance characteristics to a CT or a CC.

PGE evaluated each portfolio under 23 different "futures." These futures include combinations of varying factors such as natural gas prices (reference case and high), carbon prices (reference case, high, and zero), and load growth (reference case, high, and low). For instance, one future includes reference case carbon prices, natural gas prices, and load forecasts while another includes high carbon prices, high natural gas prices, and a high load forecast. After testing all portfolios under each future, PGE chose a subset of ten portfolios for further analysis. Included in this subset were portfolios designated as "action plan portfolios," meaning PGE considered them viable. PGE explains that the thirteen other portfolios were excluded because:

> Generally, these portfolios include potentially incomplete resource cost estimates, include a primary resource action that is beyond the Action Plan time horizon in this IRP, or fail to plan for achieving PGE's established resource adequacy targets.[1]

The action plan portfolios were evaluated in a scorecard, where different metrics were assigned weights. Half of the scored weight for each portfolio was assigned on the basis of net present value of revenue requirements (NPVRR) in the reference case (only). The other half of the scored weight was based on PGE's evaluation of risk in what PGE calls "severity," "variability," and "durability." PGE weighted the three risk metrics and then used the total combined cost and risk score to rank portfolios against one another. As a result of this process, PGE narrowed its action plan choices to the "top-four performing portfolios,"[2] called RPS Wind 2018, Wind 2018, Wind 2018 Long, and Efficient Capacity 2021. During its stakeholder process, PGE agreed that these four portfolios were only narrowly distinguished from one another in terms of cost and risk. However, PGE ultimately concluded that its "preferred portfolio" was Efficient Capacity 2021—the only portfolio of the four that includes the assumed addition of a new NGCC plant by 2021.

II. PGE 2016 IRP does not provide the Commission with a legitimate long-term plan

The 2016 IRP has not provided the Commission with a specific resource decision, only with PGE's plan to procure a large amount of "efficient capacity" in the near future. This resource was assumed to be a new NGCC plant in the IRP. However, using PGE's IRP analysis to justify building a NGCC would be unfounded and premature, especially since PGE also dismissed portfolios potentially lower-cost than its preferred plan, failed to adequately assess risk, and

[1] PGE 2016 IRP, p. 315.
[2] PGE 2016 IRP, p. 337.

ranked portfolios using improper metrics and arbitrary weighting, as we will discuss in Section III. PGE has explicitly claimed that it has not, in fact, settled on building a new NGCC plant—even though this resource addition is the key component of its preferred plan. Instead, it has merely laid the groundwork to commit to this decision in a future request-for-proposals (RFP) process. Even if PGE were committing to this resource at this time, the justification would be based on an incomplete modeling methodology involving arbitrary, pre-determined portfolios of resources—many of which are "proxy" resources.

A. PGE is delaying making a specific resource decision in this IRP

We discuss below why PGE's portfolio structure and methodology are severely flawed. For now, we focus on the fact that PGE, by its own description, claims to have failed to come up with a specific plan. Instead of selecting a specific set of resources to acquire, PGE claims that it will procure an unspecified mix of resources with the goal of achieving renewable portfolio standard (RPS) compliance and resource adequacy. This lack of specificity is simply not acceptable in a long-term planning case. PGE is obligated to produce an IRP that evaluates "all known resources" and tests "various operating characteristics, resource types, fuels and sources, [and] technologies."[3] In this IRP, however, PGE has merely gestured at evaluating actual resources with realistic costs and performance data. PGE conducted an analysis of 21 portfolios under 23 futures, held many stakeholder meetings, and ultimately produced an IRP nearly 900 pages in length. However, as a result of this long process, the Company has failed to "select a portfolio of resources," in disregard for Oregon Public Utility Commission (OPUC) rules.[4] Unsurprisingly, PGE's shallow analysis has left the Company without grounds to make a firm resource decision, a fact that PGE itself recognizes:

> …the similarity of the results across portfolios indicates it is not appropriate to constrain the types or quantities of future resource procurement to the exact resources modeled in the preferred portfolio.[5]

In other words, despite identifying the Efficient Capacity 2021 portfolio as its preferred course, PGE does not commit to procuring the resources in that plan. PGE's stance in this matter defeats the fundamental purpose of an IRP: to provide the Commission sound oversight of the Company's planned acquisition and use of resources. Instead of affording the Commission and stakeholders the opportunity to critique its actual resource plans in this proceeding, the Company claims that it is deferring specific resource decisions until after issuing RFPs at a later date:

> PGE notes that the portfolios scored in the IRP are based on cost estimates for new proxy resources that could be viable options to meet PGE's needs for RPS compliance, dispatchable capacity, and traditional capacity. The competitive bidding process provides the opportunity for new and existing resources

[3] OPUC IRP Rules, Guidelines 1a and 4h.
[4] OPUC IRP Rules, Guideline 1c.
[5] PGE 2016 IRP, p. 344.

> (including unbundled RECs, hydro resources, and natural gas plants) to bring reduced cost and risk.[6]

PGE's claim that its IRP is not sufficient to determine a specific resource plan has two main problems. First, as above, it positions the IRP as merely a prelude to the evaluation of an RFP—a process that lacks comparable Commission oversight and stakeholder involvement to this proceeding. Second, it demonstrates that PGE has failed to meet its obligations with regards to the preparation of this IRP. It is certainly within PGE's power to collect data on potential resources before conducting the IRP analysis. Indeed, PGE is currently pursuing "due diligence" for the main resource action which is fully within its own control—construction of new natural gas-fired units at the Carty site.[7] For resources such as wind, hydro contracts, and energy efficiency, however, PGE neglected to collect sufficient information to allow it to realistically evaluate resource costs and availabilities.

<u>Recommendation:</u> If the resource decision is not made in this docket, PGE must actively include stakeholders in future procurement decisions, including the evaluation of the bids received. This forum must allow for similar transparency, stakeholder access, and level of rigor as a litigated IRP proceeding.

B. A specific resource decision based on <u>this</u> IRP would be unfounded and premature

Ultimately, we agree that PGE cannot base major near-term resource decisions on the results in this IRP, given the severe flaws and omissions in its analysis. Most notably, PGE failed to develop meaningful portfolios to test—again, in violation of OPUC rules.[8] We discuss below the three primary barriers that prevent PGE from responsibly proceeding with major near-term resource commitments on the basis of this IRP: PGE's portfolios are not optimized; PGE relies too heavily on proxy resources; and, as a result of these decisions, portfolio cost results depend largely on PGE's assumptions regarding proxies and the market.

PGE did not conduct capacity optimization modeling

Unlike many utilities with state-of-the-art planning practices, PGE did not use "capacity expansion" modeling to form its candidate resource portfolios. Capacity expansion models are important because they review customer peak and energy demand, as well as current and projected resource costs, characteristics, and availabilities. Using these inputs and constraints, models can select to build resources as required to meet those demands at the lowest possible cost. Key conditions—such as natural gas and carbon prices—will affect not only how often existing resources operate but also what capacity is added or retired. For instance, if a utility

[6] PGE response to OPUC DR 1a.
[7] PGE 2016 IRP, p. 346.
[8] OPUC IRP rules, Guideline 4h.

knew that natural gas prices were going to skyrocket, it might think twice about building a new natural gas generator. A capacity expansion model will refine this thinking by determining the optimal amount of gas-fired capacity given a certain gas price trajectory. Typically, capacity expansion models are populated with a large number of supply-side (and sometimes demand-side) resources and given the freedom to choose the least-cost mix of resources. Had the Company conducted this type of modeling, it could have rigorously tested the portfolio mix selected by the optimization model against various market conditions. Numerous other utilities use this framework in their long-term planning processes.[9] Instead, the Company's portfolios are pre-determined, and much of the capacity added is little more than filler—modeled as natural gas combustion turbines or natural gas combined-cycle units, as described below.

Without the objectivity of an algorithmic approach to portfolio formation, stakeholders and the Commission are left to simply trust PGE's judgment that it has chosen an appropriate mix of resources to evaluate. Multiple parties have expressed concern regarding this issue. Sierra Club raised the question of capacity expansion modeling during PGE's pre-filing stakeholder process and received no response. In this proceeding, Industrial Customers of Northwest Utilities (ICNU) has asked PGE for clarification as to how it determined the specific amounts of resourced to add, "as opposed to some lesser or greater number."[10] With regards to wind resources in particular, the Company's sole justification for selecting a certain amount of wind to include was that "PGE concluded 175 MWa of wind generation was a reasonable quantity that captured available tax credits without exceeding mid-term RPS obligations."[11]

This response is far from satisfactory. Stakeholders are left to wonder whether some higher or lower amount of any given resource would have been more cost-effective or whether a different ratio of resources would have yielded a more favorable result. For example, the Company formed several portfolios by adding new wind in an amount equivalent in energy to a particular fossil-fired resource—for example, the Colstrip Wind 2030 portfolio replaced Colstrip with Montana wind on an equivalent expected energy basis[12] and the Wind 2018 Long portfolio replaces an assumed CC with wind.[13] The Wind 2018 Long portfolio scored only two "points" out of 100 below the preferred portfolio.[14] Whether slightly more wind, or a slightly greater reliance on market purchases, would have led to lower costs is impossible to ascertain.

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[9] Such utilities include PNM, Excel, AEP, Southern Company, KU/LG&E, Consumers, DTE, and TVA, among others. See, for example: Pacificorp. 2017 Integrated Resource Plan: Portfolio Development Detail. September 8, 2016. Available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_2017_IRP_09_08_16_Portfolio_Development_Detail.pdf

[10] ICNU DR 26.

[11] PGE response to ICNU DR 26.

[12] PGE 2016 IRP, p. 830.

[13] PGE 2016 IRP, p. 812.

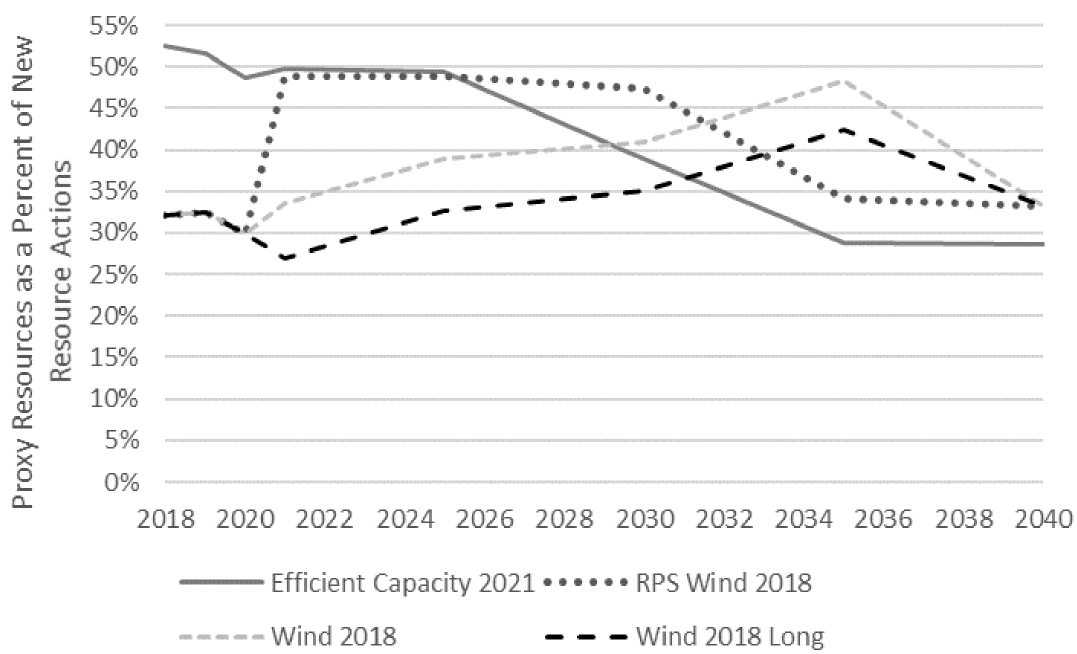
[14] PGE 2016 IRP, p. 337.

<u>Recommendation:</u> PGE must conduct capacity expansion modeling in order to optimize resource selection. Currently, there is no way of evaluating a least-cost resource decision in PGE's limited framework.

PGE's portfolios rely on capacity from unspecified and ill-defined sources

As discussed above, PGE developed portfolios of pre-determined resource mixes which generally meet energy and capacity obligations while also complying with the Oregon RPS. PGE then tested these portfolios under "futures" to determine the NPVRR under different conditions—focusing on variations of carbon, natural gas, and load forecasts. However, while the mix of specific resources changes between portfolios, the bulk of PGE's new capacity builds is comprised of proxy resources. The prominence of proxy resources varies from portfolio to portfolio, as PGE used "generic" capacity to supply any resource need that was left over after it hand-picked specific resources to add. However, in many cases these resources come to represent a significant fraction—over a fifth—of PGE's resource fleet, and approximately half of its near-term resource decisions, over the course of the planning horizon—shown in Figure 1.

Figure 1: Proxy Resources by Portfolio (% of new capacity)



PGE leaves the Commission with two unsatisfactory possibilities, both of which may be true to some extent. One possibility is that these resources are true "proxies" and PGE does in fact intend for *any* cost-effective mix of resources to be able to supply the associated energy and capacity. In this case, PGE is essentially asserting that, as soon as four years from the present, the composition of a sixth of its total resource mix will be a complete mystery. Will this portion of PGE's fleet be a mix of hydro, wind, and seasonal contracts—or will it be a CC and a CT, fired with natural gas? PGE claims that it cannot know.

The other possibility is that PGE does, in fact, have a strong sense of what resources will fill these gaps—and that it will be an NGCC. PGE chose to model these resources as new gas-fired units, rather than contracts, hydro, or any other type of resource. PGE's apparent capacity need is in 2021, and new NGCCs typically require four to five years to permit and construct. If PGE plans to acquire a new NGCC, it does not have time to wait until the next IRP cycle to demonstrate the cost effectiveness of this specific resource. As such, PGE has clearly stated its intent to procure a new resource as a result of this IRP, without explicitly identifying what resource it intends to procure. By deferring any explicit resource decisions until an RFP, PGE has effectively denied stakeholders the opportunity to be involved in PGE's actual resource planning.

The goal of an IRP is to evaluate resource options against one another to arrive at a low-cost, low-risk portfolio of resources for the coming years. PGE's heavy reliance on proxy resources—modeled as natural gas-fired units—has precluded its ability to evaluate actual resources against one another. Again, PGE claims that it cannot perform this evaluation until it issues an RFP. Even given a robust response from the market, however, PGE's IRP does not provide solid ground on which to evaluate bids from different resource types. Nor does it provide stakeholders or the Commission with certainty regarding PGE's plans for resource acquisition in the near future.

Differences in portfolios costs are* [redacted] *spending on proxies and the market

As discussed above, PGE's modeling resulted in identification of four "top-performing" portfolios. The difference in cost between these portfolios is small—indeed, [redacted] than the differences in PGE's planned spending on the market and on proxy resources in the different portfolios. As such, small changes in assumptions regarding the costs of proxy resources or of the market could have easily altered PGE's choice of a preferred portfolio. PGE's spending on the market and on its new proxy resources are generally at least [redacted],[15] each, of the total NPVRR of its portfolios across different scenarios, while the differences in NPVRR between portfolios represent a [redacted] proportion of total NPVRR.

The figure below demonstrates this point. The dark bars show the difference between the Reference Case NPVRR of various high-performing, wind-centered portfolios as compared to the total NPVRR of the preferred portfolio (Efficient Capacity 2021). The pale bars show the difference in the NPVRR of PGE's purchases on the WECC market in the Reference Case. In every case, the total difference in portfolio costs is [redacted] than the total difference in market spending.[16] Indeed, the total difference in cost between the RPS Wind 2018 portfolio

[15] PGE 2016 IRP, Appendix L; PGE Response to ICNU DR 10.
[16] PGE 2016 IRP, Appendix L; PGE Response to ICNU DR 10.

and the preferred portfolio is only [redacted] of the difference in market spending in these portfolios.

[redacted]

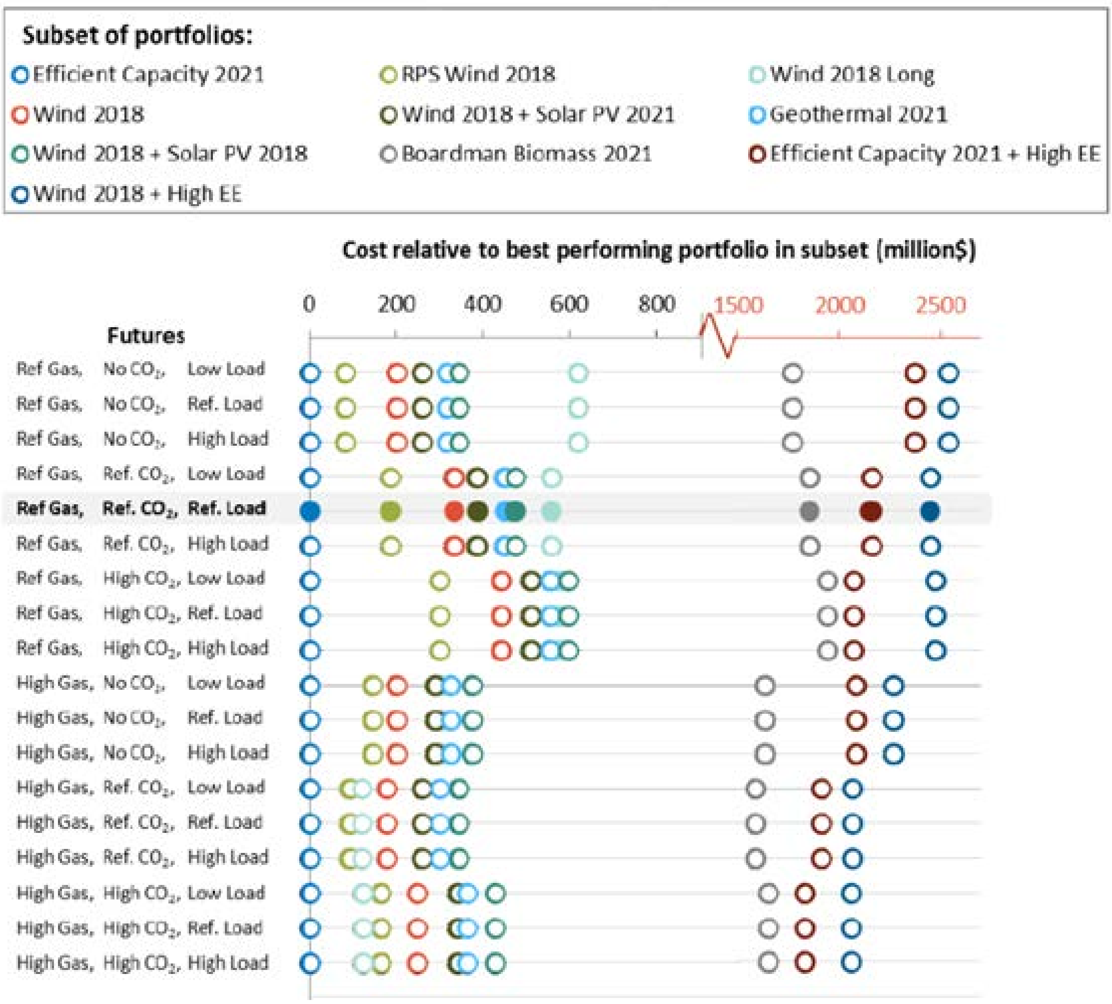
In other words, even a small error in PGE's assumptions regarding the likely cost of market energy in WECC—which depends largely on regional load, the resource mix of the region, and the costs of fuel and emissions—may have caused its preferred portfolio to appear more favorable than other plans. Often, utilities conduct probabilistic or stochastic analyses to explore the impact of unpredictable variations in factors such as market energy prices, allowing them to measure how sensitive their findings are to such changes. However, as discussed below, PGE neglected to perform such an analysis for this IRP.

The above figure also demonstrates that, in general, wind-dominant portfolios have [redacted] total market costs than the preferred portfolio. This result reflects PGE's conclusion that a new NGCC would fare well on the energy market. However, by definition, this result depends on the Company’s assumptions about the set of units that is likely to be built and operated in the rest of the west (i.e., the local energy market). A new NGCC looks attractive even under high carbon and high gas prices because the Company assumes that such a resource will be more efficient and have a lower emissions rate than the market at-large. But the Company modeled the regional market as having a much higher carbon-intensity outside its territory, as a result of its assumption that western coal capacity will not change with different carbon prices or natural gas prices[17] This is unrealistic and likely misleading, especially under a high carbon tax regime. The assumption that the Company will be able to arbitrage the carbon intensity of its fleet compared to the region as a whole is based on the notion that other utilities are unlikely to respond to the same price or regulatory signals as PGE.

PGE's focus on minimizing its exposure to an unrealistically carbon-intensive and costly market is underscored by the results of its analysis of different load futures. PGE evaluated three different load forecasts: Reference, Low, and High. The figure below shows the results for a subset of portfolios under various futures.[18] The cost reported in this figure is the difference in NPVRR between each portfolio and the preferred portfolio (Efficient Capacity 2021) under each future. Note that this difference in NPVRR does not change with load expectations. The reference, low, and high load results are the exact same, all else equal. Thus, the load sensitivity does nothing to change the ranking of portfolios amongst each other.

[17] PGE 2016 IRP, p. 799,
[18] PGE 2016 IRP, p. 766.

Figure 3: NPVRR Costs of Action Plans Relative to Preferred Portfolio ($millions)



This result shows that the load levels do not influence the choice of portfolio. This is counterintuitive as one would expect resource procurement to change with load expectations. However, PGE did not vary the amount of capacity procured with load. The Company claimed that "the load sensitivity is intended to identify economic risks *associated with varying levels of exposure to market energy* for a given portfolio."[19] The results merely tell us that if PGE procured a <u>fixed</u> level and mix of capacity, it would buy more (and sell less) on the market if load were higher, or buy less (and sell more) if load were lower. This is not surprising but also not informative. This result emphasizes the impact of PGE's market assumptions on its portfolio results, the scoring thereof, and—ultimately—its selection of a preferred portfolio.

[19] PGE response to Sierra Club DR 5; emphasis added.

<u>Recommendation:</u> PGE should evaluate specific resource options throughout the entire analysis period, including gathering sufficient data and allowing capacity builds to change with load expectations.

III. PGE's flawed analysis is biased towards building a new natural gas combined-cycle plant

In addition to its methodological weaknesses, PGE's analysis is unfairly tilted towards the acquisition of a new CC. Several elements of PGE's IRP work in favor of a new CC as compared to other resources: First, PGE failed to adequately assess the risks of different portfolios, leading it to undervalue the downside and overvalue the upside of a new gas-fired unit. Second, although it was able to fully represent the costs of new gas-fired units, PGE neglected to collect sufficient information to adequately represent the costs of new wind resources outside of its territory. Lacking such information, PGE dismissed such portfolios out of hand. Third, PGE's claims of avoided emissions are probably inflated. Finally, PGE has likely overstated its need for new capacity in the first place. In total, these factors also underscore the risks of committing to a major new resource acquisition on the basis of this IRP.

A. PGE did not adequately assess risk

PGE did not conduct a stochastic analysis and therefore cannot adequately assess the risk profile of different portfolios

PGE tested portfolios under fixed combinations of market outcomes (e.g., High CO_2/High Gas/High Load) without taking a stance on the probability of each market outcome occurring. Under this methodology, there is a wide range of cost outcomes for each portfolio. PGE's reference case includes its assumptions for a reference carbon price, natural gas price, and load forecast. The other cost results are based on variations around that reference case. Notably, they skew above the reference case. This is due to the Company not testing under a low natural gas price future—only a "reference" and a high natural gas price future. However, by not assigning probabilities of any of the cases occurring, PGE is effectively treating every other scenario as if it had an equal likelihood of occurring. This is not the case.

It is common utility practice to conduct probabilistic analysis to account for uncertainty. In that type of analysis, the probabilities are assigned for each event. For instance, one could assume that the reference gas price has a 75 percent chance of happening while the high price only has a 25 percent chance of happening. One could also assume that the reference carbon price has a 50 percent chance of occurring while the low and high each have a 25 percent chance. For combinations of these futures, the probabilities would look like the following:

Table 1: Example of Probability Assignment

Probability	Reference Gas (75%)	High Gas (25%)
No Carbon (25%)	19%	6%
Reference Carbon (50%)	38%	13%
High Carbon (25%)	19%	6%

The example above is a basic one using only two variables with illustrative probabilities assigned. In practice, probabilities could be applied to each "future." An even more sophisticated and meaningful approach would be to conduct stochastic (or Monte Carlo) analysis whereby each variable is given a probability distribution and the model randomly selects combinations of these variables—given the likelihood of each variable occurring. This generally accepted method allows for a robust analysis of the myriad risks at play. Such an analysis has been used in other IRPs filed recently in Oregon and will be used in future IRPs.[20] PGE actually conducted a stochastic analysis in its 2009 and 2013 IRPs.[21] In contrast, in its latest IRP, PGE has conducted a simplistic analysis that does not attempt to account for the likelihood of different futures occurring.

The Company attempted to justify lack of a stochastic analysis:

> In PGE's view, there was no strong justification to weight any one scenario as more likely than another…Weighting futures by probability would be incompatible with the current portfolio scoring methodology as the final portfolio scores are based on relative values and relative counts. Furthermore, PGE does not have any supporting data to assume any specific probability (weight) distributions on the futures.[22]

What this response fails to address is that by not applying specific weights, the Company is effectively weighting them all equally—before applying scoring metrics. As we describe below, the weights PGE chooses to apply to those scoring metrics are arbitrary and not backed by any "supporting data." PGE applies weights to its scoring metrics but not its key variables underlying its portfolio cost results.

[20] Idaho Power. 2015 Integrated Resource Plan. June 2015. Available at: https://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/irp/2015/2015IRP.pdf.
Pacificorp. 2017 Integrated Resource Plan: Portfolio Development Detail. September 22-23, 2016. Available at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_2017_IRP_PIM04_9-22-2016_to_9-23-2016.pdf

[21] PGE 2009 IRP. OPUC Docket No. LC 48.

[22] PGE response to OPUC DR 54.

<u>Recommendation:</u> In future IRPs or in an update to this IRP, PGE should conduct stochastic analyses to evaluate risk and ascertain the robustness of its modeling results.

PGE's scoring metrics are misleading and the weighting applied to them is arbitrary

The Company's approach introduces a skewed view of risk that does not give the Company, the Commission, or stakeholders useful information with which to evaluate various portfolio options. Instead, PGE has developed flawed scoring metrics which, after being weighted arbitrarily, are used to justify its preferred plan. These scoring metrics are meant to enable comparison of modeling results across futures and portfolios. Costs from different futures are often not comparable to one another; for example, a future with a high gas price assumption will generally yield higher costs across all resource portfolios than a future with lower gas prices. Arriving at this result would not be surprising, nor informative in and of itself. The risks themselves are also not equally likely to occur. The highest- and lowest-cost scenarios tend to be the least likely to occur and should therefore be given lower weights. Utilities perform stochastic or probabilistic analyses such as those described above in order to be able to weigh futures according to their likelihood, thereby allowing more useful comparisons.

Because PGE did not perform probabilistic analysis, it could not directly compare risk-weighted costs from different futures. Instead, it relied on a set of scoring metrics to arrive at a portfolio "score" out of 100 possible points. Out of 100 possible points, 50 are allocated to cost in the reference case, with the cheapest portfolio getting the most points. The remaining 50 are split between: "severity" (a measure of the cost of the three most expensive scenarios for each portfolio); "variability" (a measure of the range of costs that fall above cost in the reference case, with more expensive cases weighted more heavily); and "durability" (a measure of how often a given portfolio is among the cheapest, the mid-range, or the most expensive across the tested futures). Severity, variability, and durability are weighted equally to one another, and together account for the remaining 50 points. The particular combination of metrics used by the Company and the weighting of various metrics relative to one another are unique to PGE's 2016 IRP. PGE's proposed scoring methodology has not been justified or employed previously by the Company or, in Sierra Club's knowledge, other utilities.

PGE's crude scoring methodology is weak in a number of important ways. First, the scoring methodology fails to clearly identify a single top-performing portfolio. As the Company and stakeholders have noted, the scores of the top-four performing portfolios are separated from one another by only six "points"[23] (in other words, by less than the total weighted value of any individual metric). This narrow distribution indicates that the Company's scoring method is not yielding the most useful information to identify *one* preferred portfolio. Indeed, in an October 19, 2016, stakeholder meeting, PGE demonstrated that its choice of preferred portfolio could

[23] PGE 2016 IRP, p. 337.

shift depending on relatively small changes in the weighting of the different risk metrics, showing that the Company's approach is not robust or reliable.

This demonstration is of particular concern because PGE's weighting of metrics relative to one another in its scoring method is arbitrary. The Oregon Public Utility Commission guidelines state only that utilities should rely on present value revenue requirements as the key metric of cost and that utilities should measure portfolio risk by using at least two separate measures which address the variability of costs and the severity of high-cost outcomes.[24] Nowhere do the guidelines direct the Company to "balance" cost and risk by assigning both equal weight in portfolio evaluation. The Company did not, and cannot, support its choice of a half-and-half split as the appropriate approach to seeking the portfolio with the "best combination" of cost and risk. Likewise, the Company has not justified its arbitrary designation of relative weight of the risk metrics to one another.

Next, the metrics themselves are flawed and vulnerable to distortionary results. As discussed above, PGE's selection of futures has already biased its portfolio results towards higher-than-reference costs. Compounding this, the Company's scoring metrics and weighting overemphasize these costs. The severity metric examines *only* the three highest-cost results for any given portfolio, which are also the highest-weighted costs in the variability metric and also influence the durability metric. Importantly, these three highest-cost results are the same for every portfolio, resulting from the scenarios in which high gas prices are paired with high CO_2 prices, high load, or both. As such, these three results, no matter how unlikely, have an extreme influence on a portfolio's ultimate score. Severity does not need to be used in ranking portfolios against one another—as PGE does now. Alternatively, the severity metric could be used as a way of screening out portfolios. For instance, one could eliminate portfolios with extremely high 95^{th} percentile costs results.

Correspondingly, PGE's method underrepresents low-cost results, and therefore fails to truly capture variability across portfolios and futures. Only the durability metric takes any lower-than-reference costs into account and it does so only if a portfolio scores in the cheapest third of all portfolios in a given future. This creates an arbitrary threshold effect whereby a portfolio in the 33^{rd} percentile of costs (i.e., the bottom third) in all futures it would receive a 100—the highest score—but one in the 34^{th} percentile would get a score of 0. This system assigns the same score to a portfolio that always ended up "in the middle" to a portfolio that scored in the cheapest third in half of all futures and the costliest third in the other half. This is a poor measure of the balance of "good" and "bad" outcomes: "reliably good" is an important characterization of a portfolio's risks and is distinct from "sometimes excellent and sometimes terrible." The Company's method obscures the differences between the two. Indeed, taken as an aggregate, the metrics used by PGE systematically undervalue centrality of costs. The Company's decision to focus on the absolute highest-cost portfolio results, regardless of their likelihood and to the lack of emphasis

[24] PGE 2016 IRP, p. 296.

on central and “middle” outcomes, is a shallow and unhelpful representation of the concept of risk.

Instead, the Company should have employed a standard measure of variance that took both high- and low-cost results into account. This type of risk metric would be more robust and transparent. The Company chose to not follow standard practice, and it went beyond Commission directives in selecting its metrics and scoring methods. The Company’s approach introduces a skewed view of risk that does not give the Company, the Commission, or stakeholders useful information with which to evaluate various portfolio options.

PGE disagrees with these critiques, noting that:

> The scoring metrics and weightings for the 2016 IRP are similar to the 2009 IRP, which also used a balanced 50/50 weighting of cost and risk and included risk metrics for variability, severity, and durability. With respect to the construction of the severity metric, PGE considered OPUC staff and stakeholder comments in the 2009 IRP, which emphasized the importance of severity metrics that consider the absolute cost of high cost outcomes, rather than the cost relative to the reference or expected case.[25]

and:

> The durability metric was included in the acknowledged 2009 IRP scoring and continues to provide valuable information to the scoring process.[26]

However, while the names may have not changed, the methodologies underlying PGE's scoring metrics have changed quite a bit since the 2009 IRP (which employed a stochastic analysis). Moreover, PGE employed a wider range of scoring metrics in 2009, covering factors such as portfolios' fuel mix and year-to-year variance in costs.[27] As such, these scoring methods are not directly comparable.

PGE's choice of scoring metrics directly led to its selection of Efficient Capacity 2021 as the preferred portfolio. According to PGE, a different weighting of the same metrics may have led to a different choice. Notably, the preferred portfolio's variability score, representing the total risk of worse-than-reference case outcomes, is much worse than any of the other top-performing portfolios, while its severity score is only slightly superior. The preferred portfolio's poor variability score proceeds from its significant vulnerability to cost increases given high gas prices, while its higher severity score reflects PGE's assumptions with regards to the costs of a new NGCC versus the WECC market as a whole. However, an unusually poor variability score did not lead PGE to reject Efficient Capacity 2021 as its preferred portfolio. In effect, by relying on this particular set of scoring metrics, PGE has decided that its risk of market exposure should be minimized compared to its risk of exposure to high gas prices. The finding that a gas-heavy

[25] PGE Response to RNW DR 1.
[26] PGE response to RNW DR 2d.
[27] PGE 2009 IRP, p. 287.

portfolio will suffer under high gas prices is an intuitive one. Meanwhile, as discussed above, PGE's findings regarding the WECC market likely proceed from its assumption that none of the Western utilities will respond to clear price and policy signals by retiring existing coal units—an assumption that is dubious.

Recommendation: PGE must drastically change scoring metrics. It should use "severity" as a screening metric; change "variability" to include lower cost results; and remove "durability" completely.

B. PGE dismissed lower-cost portfolios after willfully failing to properly assess them

PGE has placed false barriers to procuring resources that are not a new NGCC. The Company screened out several low-cost portfolios that include procurement of wind resources in Montana: Diverse Wind 2021, Colstrip Wind 2030, and Colstrip Wind 2035. The latter two assume more wind is procured as PGE retires its share of the Colstrip coal plant. All three portfolios had lower NPVRR costs (in the reference case) than the Company's preferred plan, yet these were excluded from being action plans because PGE did not estimate transmission costs.[28] PGE purposefully neglected to develop transmission costs, as they explained:

> The difference in cost between portfolios can serve as a reasonable proxy for the budget that could be allocated to securing the transmission capability needed in order to deliver the energy from a remote wind site. This approach was preferred to performing a speculative analysis comparing potential use of existing transmission rights to using rights from building new transmission of uncertain cost.[29]

This approach unreasonably precludes the Company from choosing portfolios that would require new transmission. This is an oversight that, again, biases the IRP analysis towards the building of an NGCC in its territory. It is also another example of passive planning on the part of PGE. The company is adopting a "wait and see" approach rather than an active approach. Montana wind has been developing rapidly in recent years and is expected to continue to do so. The partial or full retirement of Colstrip will free up significant transmission resources moving east to west from Montana for the rest of the Pacific Northwest.[30] Indeed, a 300 MW wind farm has been proposed by Clearwater Energy—almost half of the state's current wind capacity.[31] This wind

[28] PGE 2016 IRP, p. 805.
[29] PGE response to OPUC DR 82.
[30] Puget Sound Energy recently filed a plan with the Washington Utilities and Transportation Commission stating that it intends to close Colstrip Units 1 and 2 by 2022 at the latest and could close the units earlier depending on external factors. The filing also requested an accelerated depreciation date (for Washington) to 2035 for Units 3 and 4. UTC Docket UE-170033.
[31] Lutey, Tom. 2016. "Montana's largest wind farm quietly develops northeast of Colstrip." *Billings Gazette*. April 17.

farm would be located near the Colstrip plant due to available wind resources and transmission access. The project's proponents and other stakeholders (including Bonneville Power Authority) are also evaluating upgrades to the transmission system to accommodate 700 MW of wind at that site. The developer has already applied for approval to interconnect 750 MW on the NorthWestern system, though this process is still in the beginning stages.[32]

In fact, PGE, along with Puget Sound Energy (PSE), has been taking actions elsewhere that might prevent further procurement of Montana wind. Both companies opposed the removal of the Bonneville Power Administration (BPA) Eastern Intertie rate tied to a transmission spur in Montana. Currently, there is 184 MW of transmission that is unsubscribed at the Intertie. In their 2016 rate case, BPA showed that removing the rate could lead to rate decreases on the BPA network if more wind were subscribed or a de minimis increase if no additional wind were subscribed.[33]

The Commission directed PGE to "to thoroughly examine and analyze various shutdown scenarios for Colstrip in its next IRP process."[34] The Company has failed to adequately assess the shutdown of Colstrip by failing to evaluate the use of valuable transmission capacity once the plant is retired.

> PGE is not in negotiations to secure existing transmission rights associated with any retiring coal plants listed on page 13 as PGE currently has no plans to construct any resources which could take advantage of the transmission rights associated with the retiring coal plants. Any new resources which PGE might acquire through the RFP process would be expected to bid into the RFP with sufficient transmission to deliver energy to PGE load.[35]

New transmission projects could facilitate low-cost renewable energy to the PGE system, yet the Company ignored this prospect. The Company attempts to predict the future about many other things in this IRP: gas prices, load growth, carbon prices, capital costs of various resources, retirements, etc. PGE currently has transmission access into Montana as a co-owner of Colstrip. To ignore transmission costs associated with Montana wind is simply negligent. PGE has claimed that now is not the appropriate time to evaluate resource decisions that are many years in the future; however, this is the fundamental goal of long-term planning and making a major resource decision now may foreclose future opportunities and reduce optionality.

Even if PGE's analysis of wind portfolios included transmission costs, we would still be left with an arbitrary, fixed amount of wind—not the result of an optimization model. The Diverse Wind 2021 portfolio includes 507 MW of Montana wind in 2021. The two Colstrip wind portfolios

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[32] NorthWestern Energy. Interconnection Queue. Available at: www.oasis.oati.com/nwmt/nwmtdocs/Interconnection_queue.xls.

[33] Testimony of Dennis E. Metcalf, Rebecca E. Fredrickson, David W. Bogdon, and Stephen A. White for Bonneville Power Administration. BP-14-E-BPA-35. p.3, lines 12-24.

[34] OPUC Order 14-415. December 2, 2014. p.6.

[35] PGE response to OPUC DR 82

assume that 650 MW is installed in 2030 or 2035, respectively. Are any of these amounts of wind the lowest cost? There is simply no way for us to know unless PGE happened to choose the right number. Notwithstanding their modeling methodology, PGE should actively pursue cost-saving opportunities involving Montana wind instead of dismissing it from consideration as a result of not doing its due diligence.

Recommendation: **PGE must evaluate transmission costs for Montana wind and weight those costs in a future resource decision. PGE should also evaluate the costs of all portfolios rather than treating viable, low-cost portfolios as an academic exercise.**

C. PGE's claimed avoided emissions from its preferred plan are artificially inflated

PGE has presented a new NGCC as a more attractive and clean option than it would be in reality. In order to evaluate the emissions impact of its various portfolios, PGE modeled emissions from resources within its service territory but assumed a constant carbon intensity for energy procured on the market. The Company set this value at 0.45 tons/MWh, the average WECC emissions rate in the year 2005, and assumed that all market purchases would remain equally carbon intensive between 2017 and 2050—regardless of carbon policy.[36] According to the Company's own analysis, this value is significantly higher than the average carbon intensity of WECC now and into the future.[37] It is also much higher than the average carbon intensity of the electricity purchased by the Company, which was 0.28 tons/MWh in 2015.[38] As the Company explains, this assumption is not conservative—it is, "in practice...an *upper* bound on the emissions associated with market purchases."[39] Again, this assumption is in part a result of PGE's expectation that other Western utilities will not retire their coal-fired units, even given high carbon prices.

Because PGE buys less energy from the market when it builds more capacity in its own territory, any risk of overstating emissions due to this assumption falls predominantly on portfolios which do not include a new NGCC. Indeed, this assumption leads to the strange results seen in Figures 12-6 and 12-7 of the IRP, in which the post-2035 years see the preferred portfolio as having *lower* emissions, and a lower emissions rate, than portfolios in which PGE constructs more wind instead of a new gas-fired CC. Those figures show total emissions, inclusive of both emissions from PGE-owned or –operated resources and the market. Not shown are the emissions trajectories from only those resources which are within PGE's control, which are much lower for

[36] PGE 2016 IRP, p320. Note that the text cites a value of "0.45 lbs/MWh". We understand this to be a typographical error as the correct units (tons/MWh) are clearly marked in PGE's workpapers.
[37] PGE response to Sierra Club DR 16.
[38] PGE response to Sierra Club DR 17. PGE was requested to provide any analysis that it had conducted of the carbon intensity of its "market purchases" but provided only an accounting of the emissions associated with its purchased power, regardless of source. As such, we note that this value may include purchases under contract.
[39] PGE response to Sierra Club DR 17; emphasis added.

portfolios with increased levels of wind.[40] In other words, PGE's assumed carbon intensity of WECC leads it to the counterintuitive conclusion that wind, firmed by the market, will be more carbon-intensive than an NGCC.

<u>Recommendation:</u> PGE must use Aurora model results for WECC carbon emissions rates instead of assuming a outdated, fixed, and inflated carbon intensity for the region.

D. PGE focused on acquisitions of new capacity in lieu of existing resources

PGE has failed to conduct due diligence with resources it currently procures under contract. Numerous parties in this proceeding have expressed concern regarding PGE's assumption that many of its existing contracts will lapse in the near-term and will not be renewed. In addition to the retirement of Boardman, PGE's assumption that it will not be able to renegotiate these contracts contributes to its apparent resource need in the near-term. PGE has asserted that these assumptions are appropriate, claiming that:

> Counterparties providing capacity and energy to PGE under existing hydro contracts that expire within PGE’s Action Plan window have no obligation to renew the contracts on the same terms. Therefore, it would not be reasonable for PGE to presume that expiring hydro contracts will continue to provide PGE with energy and capacity at their existing parameters after their expiration dates.[41]

Similar to its treatment of Montana wind, PGE failed to perform the necessary research to arrive at even a reasonable estimate of the costs and characteristics of these potential future contracts. According to the Company, it is completely unable to evaluate these costs "until actual bids are received and evaluated" and any attempt to arrive at a set of "assumptions for quantity, parameters, and pricing [would be] arbitrary."[42] As such, the Commission and stakeholders are left completely without an evaluation of how likely it is that PGE will be able to renegotiate these contracts. Moreover, PGE has neglected to provide a framework with which stakeholders and the Commission can even examine whether hydro would be a cost-effective resource as compared to PGE's proxy additions of gas-fired units.

In response to continued queries from OPUC Staff, PGE repeatedly insisted that these contracts, if re-signed, could simply make up a portion of its assumed acquisition of proxy resources and that therefore "the possibility of existing regional resources contributing to PGE’s RPS and

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[40] In the Reference case, the Wind 2018 Long portfolio has yearly carbon emissions from PGE resources that are [redacted] lower, on average, than the Efficient Capacity 2021 portfolio—while carbon emissions from market purchases are [redacted] higher on average. In total, the Wind 2018 case has yearly emissions that exceed the preferred portfolio by [redacted] on average. (See PGE response to ICNU DR 21).

PGE response to OPUC DR 1a.

[42] PGE response to OPUC DR 59b.

capacity need is encompassed in PGE's action plan."[43] Despite repeated requests from Staff, PGE refused to evaluate sensitivities focused on portfolios in which PGE successfully re-signs existing contracts and acquires additional new contracts for resources (including hydro). PGE's protestations that modeling a CC or CT is equivalent to assuming that a hydro contract can be re-signed defeats the purpose of performing unit-specific electric sector modeling in the first place. The total capacity of the Company's contracts for hydropower which expire prior to 2021 would account for 15 to 20 percent of PGE's implementation of proxy resources[44]—potentially with very different cost, risk, and emissions impacts to the generic fossil-fired resources.

Recommendation: PGE should more thoroughly evaluate whether it is possible and cost-effective to renegotiate existing resource contracts and should incorporate those extended contracts into its IRP analysis.

E. The IRP underestimates PGE's cost-effective energy efficiency potential

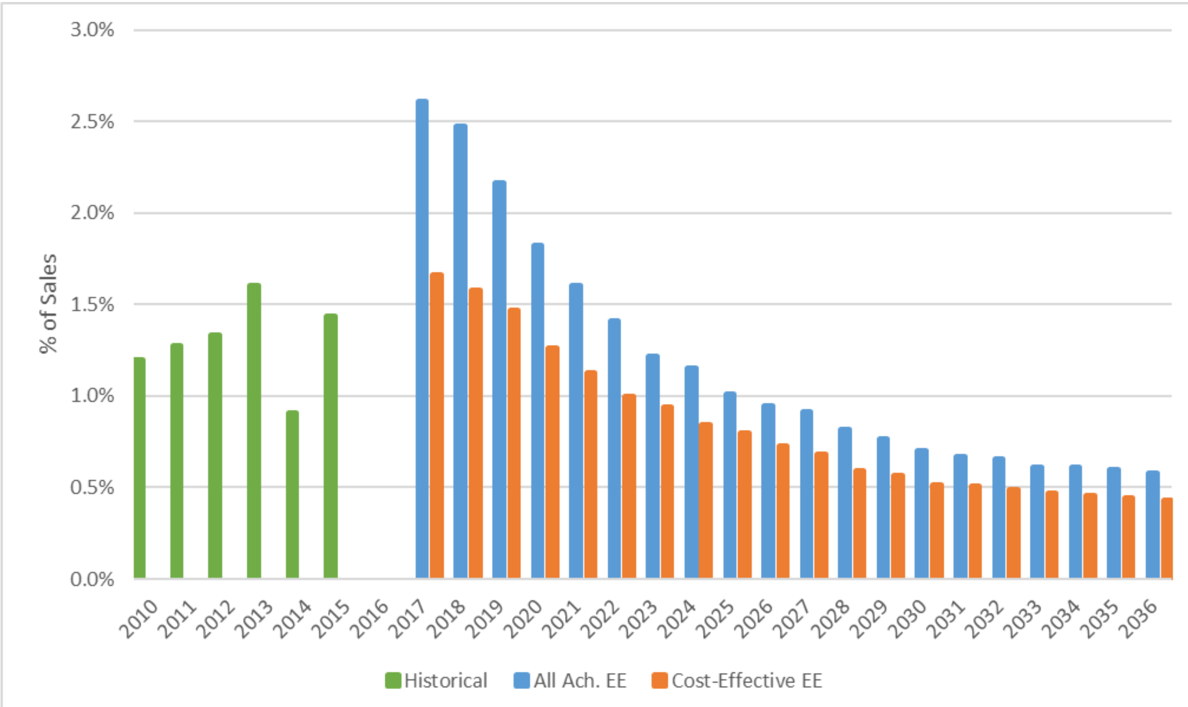
Another key factor driving PGE toward building new generation capacity is PGE's analysis of future energy efficiency (EE) potential. The level of load and energy required for PGE's territory is likely overstated as a result of EE potential being underestimated. PGE's estimates are based on recent forecasts provided by the Energy Trust of Oregon (ETO) which are flawed in three ways: (1) future savings levels are unrealistically expected to decline substantially over time; (2) the cost of all achievable EE is significantly overstated; and (3) PGE's avoided cost is likely too low, which makes EE look unreasonably unattractive.

Future savings levels are unrealistically expected to decline substantially over time

Energy efficiency programs under PGE's service territory are handled by the ETO, Oregon's statewide third-party EE program administrator. ETO has recently achieved about 1.5 percent annual savings, as shown in Figure 4 below.[45]

[43] PGE response to OPUC DR 59b.
[44] PGE response to OPUC DR 1; PGE 2016 IRP, Appendix L.
[45] Energy Trust of Oregon's annual program reports to the Oregon Public Utility Commission and Energy Trust Board of Directors.

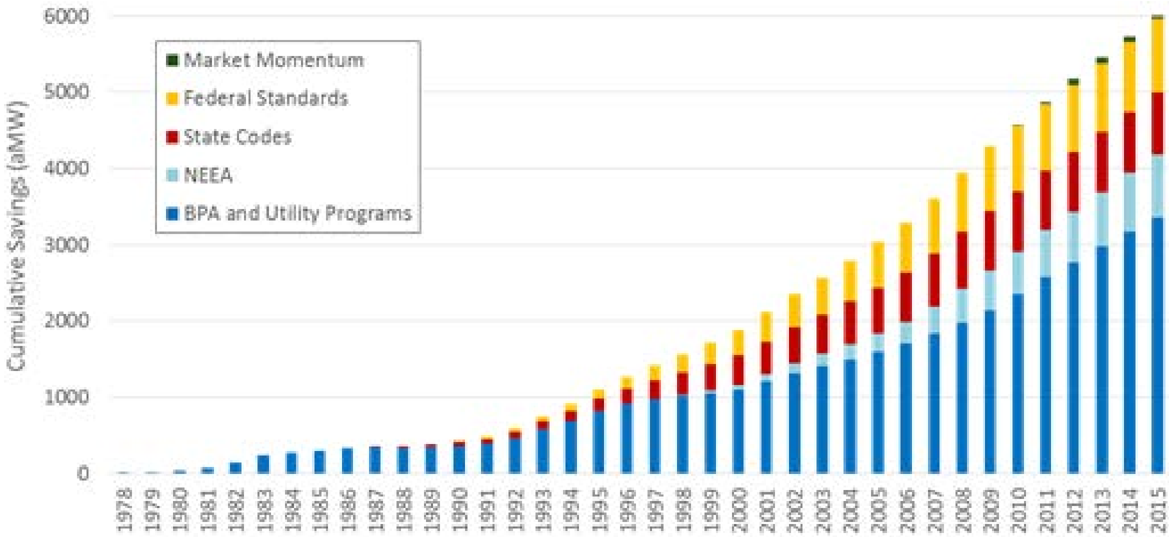
Figure 4: Historical EE Savings vs. Projected EE Savings in PGE 2016 IRP (% of annual sales)



However, PGE's IRP (which adopted ETO's recent analysis) predicts that future energy savings will substantially decline over time. Shown as "cost-effective EE" above, PGE expects a similar level of savings in 2017 at about 1.7 percent but this declines to less than 0.5 percent by 2033. The all achievable potential ("All Ach. EE" above) includes the level of EE that is technically possible yet not all of this is cost-effective. These declining savings projections are not supported by any historical evidence in the region. For example, utilities in the Northwest together have increased energy savings year by year since 1978 (shown below).[46]

[46] Seventh Northwest Conservation and Electric Power Plan – Summary Brochure, available at https://www.nwcouncil.org/media/7150076/finalplanbrochure.pdf

Figure 5: Historical Energy Savings Achievements in the Northwest Region (aMW)



The Pacific Northwest shows no sign of shedding EE savings in the future. Despite the region's impressive efforts to tap into the region's EE potential already, the latest NWPCC power plan in 2016 has found an additional 4,300 average MW (aMW) potential over the next 20 years.[47] Additional EE has the potential to avoid or at least delay construction of new generating facilities. Unfortunately, the rigid and inflexible structure of PGE's analysis does not allow for this possibility and, if it did, the effect would be muted by the faulty assumption that EE savings will rapidly diminish.

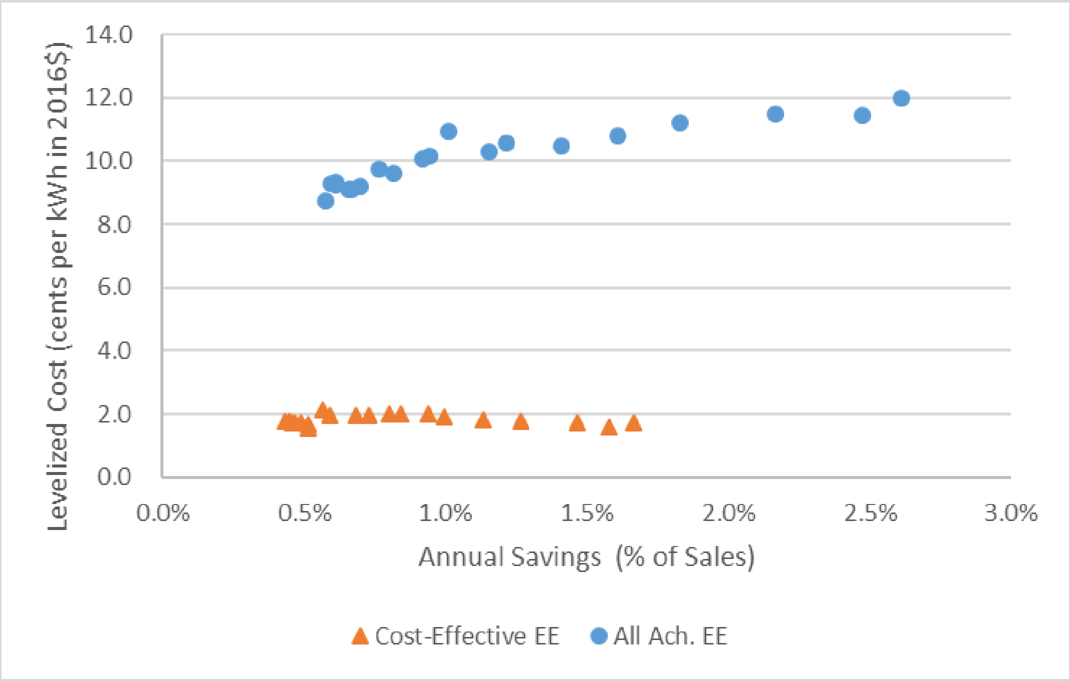
The cost of the all achievable energy efficiency is significantly overestimated

Based on the program costs and savings data provided at Table 6-1 of the IRP, we estimate that the levelized total resource cost of the efficiency programs over the lifetime of the measures is about 2 cents per kWh for cost-effective EE, and 9 to 12 cents per kWh for the all achievable EE.[48] These levelized costs are shown in Figure 6 below where we compared the cost of saved energy with the annual projected savings estimate as a percentage of sales.

[47] *Id.*

[48] We estimated these levelized costs by amortizing the projected annual "total resource costs" per annual kWh savings based on a 6.2 percent discount rate and a 14-year measure life. The discount rate is based on PGE's weighted average cost of capital used in the IRP. The measure life is based on the average measure life for ETO in 2015 which are provided in U.S. Energy Information Administration's Form 861 database.

Figure 6: Projected Costs of Saved Energy (cents per kWh) vs. Savings (% of annual sales)

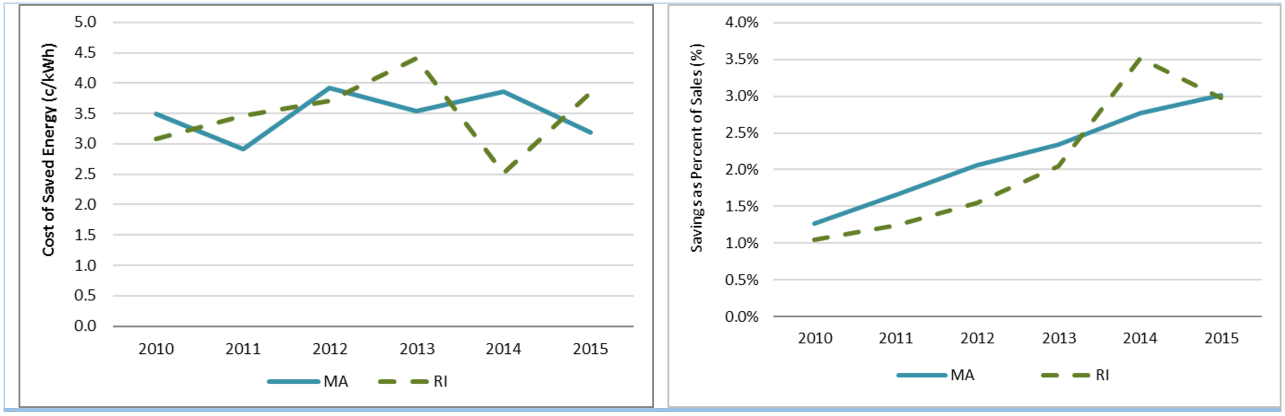


PGE is clear that these costs are "total resource costs," which include both program costs and out-of-pocket participant costs. However, the cost estimate for all achievable EE is likely too high. This projects 2 to 2.5 percent savings per year in the first few years and diminishing annual savings over time to about 0.5 percent (as shown in Figure 4). Historical evidence suggests that aggressive programs at similar savings levels will not increase program costs per kWh savings and can maintain these high levels of savings over multiple years. For example, Massachusetts and Rhode Island have achieved 2 to 3 percent annual savings in recent years, yet their program costs have been very stable at around 3 to 4 cents per kWh.[49] The total resource costs—which include participant spending—for these two states are about 4 to 6 cents per kWh.[50] This implies that the cost estimates for the all achievable EE are likely overstated.

[49] Mass Save Data, available at http://masssavedata.com/Public/Home; National Grid Rhode Island "Year-End" annual program reports

[50] "Cape Light Compact 2013-2015 Term Report, D.P.U. 16-127, Statewide Roll up tables. Our estimate is based on an assumption that the program costs for both Massachusetts and Rhode Island programs account for 70 percent of the total resource cost based on Massachusetts' 2013-2015 program results filed under Docket 16-127.

Figure 7: Savings Achievements (left, % of annual sales) and Cost of Saved Energy (right, cents per kWh) from 2010 to 2015



PGE's avoided cost estimate is too low

The avoided cost is used to identify what level of energy efficiency resources is cost-effective. PGE assumed a number that is too low: 5.3 cents per kWh.[51] This is [redacted] than the levelized cost of a new NGCC, as shown in the IRP, which is about [redacted] cents per kWh.[52] Additionally, the avoided cost should include (a) a higher avoided cost of transmission and distribution and (b) the avoided cost of carbon, which increases the threshold even further. The NWPCC uses $26 per kW-year for deferred transmission and $31 per kWh-year for deferred distribution systems to provide additional benefits to energy efficiency measures in its Seventh Power Plan. These values were developed based on the data the NWPCC collected from several transmission and distribution utilities. PGE should consider adopting these values.

Additionally, ETO uses the Total Resource Cost (TRC) test, which includes both costs and benefits experienced by program participants in addition to system costs and benefits (i.e., non-energy benefits). The IRP currently includes only quantifiable non-energy benefits such as reduced water usage.[53] This approach essentially ignores hard-to-quantify non-energy benefits. To address this issue, a number of states are incorporating such non-energy benefits in their program screening by applying proxy values such as a 10 to 20 percent benefit adder. Such an adder would increase the benefit of energy efficiency programs by 10 to 20 percent.[54] In fact,

[51] PGE 2016 IRP, p. 159.
[52] PGE 2016 IRP, Figure 7-12, p. 216
[53] PGE 2016 IRP, p. 159.
[54] See Synapse Energy Economics. 2014. Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits, Section 4.1. Available at: http://www.synapse-energy.com/sites/default/files/Final%20Report.pdf

OPUC requires state utilities to use a 10 percent conservation adder.[55] While PGE considers this adder, it ultimately ignores it when estimating its avoided cost.[56]

Recommendation: **PGE should not assume declining energy efficiency savings over the analysis period and should lower its cost for all achievable efficiency. PGE should also use a higher cost-effectiveness threshold to develop the cost-effective energy efficiency scenario by considering the cost of a new natural gas CC, higher avoided transmission and distribution, avoided carbon price, and non-energy benefits.**

IV. Summary and key recommendations

As discussed above, PGE's 2016 IRP fails to propose and justify a specific resource plan, leaving stakeholders and the Commission with little insight into the actions PGE is likely to take in the near future. What information is provided in this IRP appears unreasonably biased towards acquisition of a new gas-fired combined cycle unit. In light of these shortcomings, Sierra Club finds that PGE must make significant improvements to the current IRP to arrive at a product that merits OPUC acknowledgement:

1. **PGE must conduct capacity expansion modeling to arrive at a reasonable range of optimized resource portfolios.** It appears that PGE intends to construct such a unit but has not fully disclosed its intentions to the Commission or stakeholders. However, PGE did not rigorously test its pre-constructed portfolios against different market conditions. Instead, the Company's portfolios are pre-determined, and much of the capacity added is little more than generic filler—modeled as natural gas combustion turbines or natural gas combined-cycle units.

2. **PGE must robustly account for risks by conducting a probabilistic analysis of portfolios.** The IRP relied on a simplistic analysis of portfolios that does not account for the likelihood of different futures occurring. This treatment produces misleading results and lacks the rigor of standard utility planning.

3. **PGE must adjust its scoring methodology.** PGE's attempt to evaluate portfolio risk is misleading and ill-defined, and the weighting of its risk metrics appears arbitrary. PGE's current scoring schema undervalues low-cost results. The particular combination of

[55] Public Utility Commission of Oregon, "In the Matter of the Investigation into the Calculation and Use of Cost-Effectives Levels for Conservation," Docket UM 551, Order 94-590, April 6, 1994. Available at: http://apps.puc.state.or.us/edockets/docket.asp?DocketID=4744;
Also see Synapse Energy Economics. 2013. Energy Efficiency Cost-Effectiveness Tests, page 21. Available at http://www.synapse-energy.com/sites/default/files/Appendix%20D%20from%20Michigan%20Report.pdf

[56] PGE response to Sierra Club DR 21, Attachment A.

metrics and their weighting relative to one another are unique to this IRP and have not been justified.

4. **PGE must determine a reasonable set of assumptions regarding resources costs for all resources.** The Company claims that the IRP is not intended to choose a specific technology, despite the fact that the IRP process is meant precisely to include, as PGE states, "analysis of the various *resource options* available to meet the Company's resource needs."[57] PGE has persistently used this reasoning as an excuse for its failure to fully represent the costs and availabilities of wind, hydro, energy efficiency, and other contract resources. Unsurprisingly, PGE appears to have had no difficulty in arriving at a detailed set of assumptions regarding the characteristics of new fossil-fired resources. PGE is obligated to treat all resources even-handedly, which means adequately representing the costs and availabilities of all resource options under consideration—including extension of existing contracts. PGE must arrive at a full evaluation of the costs of all resources and represent these resources fully and fairly in representative, optimized resource portfolios.

5. **PGE must commit to stakeholder involvement in any RFP processes resulting from this IRP.** Throughout this proceeding, PGE has attempted to defer arriving at a specific resource decision until it receives bids in response to an unspecified number of RFPs, to be held at an unspecified future date. Transparency and stakeholder involvement are key aspects of an IRP proceeding. If PGE wishes to displace its actual resource planning to an RFP proceeding in lieu of bringing a specific resource plan before this Commission as part of its IRP, it must publicly commit that its issuance of these RFPs, and evaluations of bids received in response, will be conducted with comparable transparency and comparable opportunities and respect for stakeholder involvement as would be expected in any other long-term planning case. In addition, in a future IRP or RFP PGE should (1) remove the requirement for minimum "dispatchable" capacity; (2) let stakeholders have a say in the evaluation process, including the review of confidential bids throughout; and (3) not dismiss out-of-state wind as a resource and instead conduct a thorough assessment of transmission costs for bringing in out-of-state wind (or other bids for that matter).

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[57] PGE 2016 IRP, p. 46.

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Respectfully submitted,

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