ITEM NO. 1

# PUBLIC UTILITY COMMISSION OF OREGON
# STAFF REPORT
# PUBLIC MEETING DATE: December 15th, 2016

**REGULAR** ____ **CONSENT** ____ **EFFECTIVE DATE** ______ **N/A** ______

**DATE:** December 7, 2016

**TO:** Public Utility Commission

**FROM:** Michael Breish MB

JE JE for JC

**THROUGH:** Jason Eisdorfer and John Crider

**SUBJECT:** PORTLAND GENERAL ELECTRIC: (Docket No. UM 1788) Requests Acknowledgement of 2016 Revised Renewable Portfolio Standard Implementation Plan

## STAFF RECOMMENDATION:

Staff recommends the Commission acknowledge, with conditions, Portland General Electric's (PGE or Company) Revised 2016 Renewable Portfolio Standard Implementation Plan (RPIP) as having met the reporting requirements found in OAR 860-083-0400 and ORS 468A.075. Staff recommends the Commission not acknowledge PGE's response to the supplemental requirements found in Commission Order No. 16-157.[1]

Staff further recommends the following Conditions:

1. PGE must comply with the following steps when it commences a resource procurement action for the purpose of complying with the Renewable Portfolio Standards (RPS) that materially deviates from its most recently filed RPIP or integrated resource plan (IRP):

    a. Demonstrate the forecasted benefit to ratepayers if the resource or resources do not immediately satisfy a system capacity or RPS need;
    b. Explain the interaction the new resource or resources have with the most recently filed IRP or RPIP;
    c. Calculate new incremental costs with the new resource or resources included across twenty years;

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[1] *In re Portland General Electric Company*, OPUC Docket UM 1755, Order No. 16-157 (Apr. 22, 2016).

d. Respond to requests by the Commission regarding its new analysis arising out of the calculation set forth in 1(c) above.

2. PGE respond to a modified set of supplemental questions and quantitative analyses regarding its long-term RPS compliance strategies.
3. PGE meet with Staff and stakeholders to determine the specifics of the aforementioned questions and analyses.
4. PGE participate in a separate stakeholder workshop to identify opportunities for revisions to the RPIP process and requirements.

**DISCUSSION:**

*Issue*
Whether PGE's Revised 2016 RPIP meets the applicable RPS statutes, administrative rules, and Commission Order No 16-157 such that the Commission should acknowledge it with Staff's recommended Conditions.

*Applicable Law*
The RPIP serves two basic purposes: (1) it forecasts the utility's RPS compliance position and strategies, and (2) it sets forth the calculation of the utility's incremental cost of compliance with the RPS.

The RPS laws are codified at ORS 469A.005 through 469A.210. OAR 860-083-0400 is the Commission's rule addressing the RPIP. ORS 469A.075(1) and OAR 860-083-0400(1) require that each electric company subject to the RPS provide an a report at least once every two years that demonstrates its planned RPS compliance with the RPS standard over the ensuing five years.

Among the reporting details required by ORS 469A.075(2) and OAR 860-083-0400(2)(a-f), the RPIP must contain annual load forecasts, the renewable energy credits (RECs - which may include both bundled and unbundled RECs) required in order to comply with annual RPS targets, the estimated cost of meeting annual RPS targets, an account of qualifying electricity generators, and a detailed explanation of any material deviations from the electric company's most recent IRP's action plan or material changes from the conditions assumed in the most recent IRP.

In calculating costs of RPS compliance, the utility must determine the incremental costs, which is composed of bundled and unbundled REC costs as well as alternative compliance payments. If the incremental costs in any year exceed the limit of four percent established in ORS 469A.100, the utility is required to provide sufficient information that demonstrates how the RPIP appropriately balances risks and expected costs. *See* IRP guidelines 1.b and 1.c set forth in Commission Order No 07-047. [2] This requirement is also triggered if, among other reasons, the utility plans to use unbundled RECs or to sell any RECs included in the rates of retail customers.

ORS 469A.075(2) and OAR 860-083-0400(2)(a-f) further require that the RPIP provide the Commission with the information necessary to determine whether, and how, the electric company will be in compliance with the RPS over the ensuing five years.

RPS compliance must be demonstrated through the retirement of RECs that are maintained through the WREGIS.[3] RECs may be either bundled with energy or exchanged separately (unbundled).[4] One REC is issued per megawatt-hour of generation produced.[5]

RECs procured before March 31 of a given year may be used for the previous year's RPS compliance.[6] RECs issued on or before March 8, 2016 have unlimited life. RECs generated or procured from resources with a commercial operation date (COD) between March 8, 2016 and December 31, 2022 have unlimited life; these RECs are commonly referred to as "golden RECs" (Golden RECs).[7] RECs from generating resources with a COD on or before March 8, 2016 and *issued* after March 8, 2016 have only a five year-life. RECs generated after December 31, 2022 also have a five-year life.[8]

With limited exception, only 20 percent of an electric utility's RPS compliance obligation may be satisfied using unbundled RECs in any given compliance year.[9] However, ORS 469A.145(3) provides that this limitation "does not apply to renewable energy certificates issued for electricity generated in Oregon by a qualifying facility under ORS 758.505 to 758.555." The distinction for unbundled RECs generated by qualifying facilities located in Oregon, which do not apply to the 20 percent limit in a compliance year, is important to note as demonstrated later in this report.

[2] ORS 469A.100(1) states that utilities are not required to comply with the renewable portfolio standard during a compliance year if the incremental cost of compliance, the cost of unbundled renewable energy certificates and the cost of alternative compliance payments under ORS 469A.180 exceeds four percent of the utility's annual revenue requirement for the compliance year.
[3] OAR 330-160-0020.
[4] OAR 330-160-0025.
[5] OAR 330-160-0015(15).
[6] OAR 860-083-0300(3)(b)(B); also note that SB 1547 established new requirements regarding REC generation and banking privileges for future compliance years.
[7] March 8, 2016 is the effective date of SB 1547.
[8] A REC generated from a resource with which the utility has a PPA has a varying lifetime depending on the length of that PPA. *See* Section 6 of SB 1547 for further details.
[9] ORS 469A.145(1).

*Discussion and Analysis*

Background
This Staff memorandum analyzes a revised version of PGE's original 2016 RPIP (Original RPIP), which was filed on December 31, 2015.[10] During the course of Staff's and stakeholders' review of the Original RPIP, PGE filed a supplemental attachment that attempted to model preliminary changes to RPS compliance requirements that were being contemplated by the Oregon legislature. PGE's supplemental filing, the eventual passage of SB 1547, and Staff's uncertainty regarding what PGE actually planned to do given the inconsistencies with the 2013 IRP update and the pending filing of the 2016 IRP, resulted in Staff recommending the Commission acknowledge the Original RPIP with conditions and require the Company file a revised RPS implementation plan (Revised RPIP) by July 15, 2016 that included responses to several questions.[11]

In Attachment A of Commission Order No. 16-157, Staff presented five questions, the purpose of which was to provide Staff with a clear understanding of PGE's strategy in complying with the new RPS requirements over 2040 planning horizon. These questions are found in Attachment A of this memorandum. Staff felt these questions were particularly important in light of the fact that the Company was one year away from an acknowledged IRP and was seeking approval for a request for proposals (RFP) for qualifying renewable resources. Foundational to Staff's questions was the consideration of least-cost, least-risk resource acquisition planning, the temporary federal tax incentives and newly implemented RPS compliance mechanisms. PGE's response was to fill the information void for Staff and the Commission regarding the Company's long-term opportunities to comply with the RPS.

PGE's Revised 2017 – 2021 RPS Implementation Plan
PGE's Revised RPIP blends the Company's answers to the questions contained in Commission Order No. 16-157, which directs PGE to provide a narrative describing its plan to comply with the RPS through 2040 given the changes prescribed by SB 1547, with the five-year RPS compliance analysis that is required by the Commission's existing administrative rules. Though not inherently problematic, PGE in its narrative focuses more explicitly on the 2040-horizon analysis, leaving the five-year requirements more opaque, particularly the differences between pre- and post- SB 1547.

Described in greater detail later in this report, PGE constructed four procurement scenarios to model resource diversity and procurement timing. Because these scenarios do not evaluate compliance strategies that have any differences prior to 2025, the only relevance they have in five-year analysis is the slight differences in incremental

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[10] *See* OPUC Docket UM 1755.
[11] Commission Order No. 16-157.

costs each possesses, which is mentioned below. Staff identifies four major changes from the Company's Original RPIP for the 2017 – 2021 period found in the Revised RPIP that it believes are noteworthy.

First, as a result of SB 1547 and the subsequent change in REC provisions, PGE will retire five-year life RECs with the earliest vintage year to meet RPS compliance through 2021. The practical result of that strategy for PGE is that for each year, the majority of the RPS compliance requirement is met through RECs generated within that same year. Beginning in 2018, banked RECs generated in the previous year from the Biglow Canyon wind farm are used for compliance. As stated above, prior to SB 1547, statute required PGE to retire RECs on a first-in, first-out basis.

Second, a resource of RECs, titled "ETO and Other Solar" generates significantly more RECs beginning in 2020 than forecasted in the Original RPIP. This resource category, which is composed of solar qualifying facilities (QF) and other solar projects, approximately quadruples in capacity, from 12 MWa to 48 MWa. The resulting annual output, which amounts to approximately 425,000 RECs, continues through 2031. Based on Staff's analysis of the Revised RPIP's work papers and discovery, this increase largely results from additional QF contracts.

Third, PGE forecasts the procurement of a 175 MWa wind resource in 2018 across all sensitivities. No resource additions were forecasted through 2021 in the Original RPIP and PGE forecasted procuring a "Generic RPS Resource," sized 95 MWa, in 2020 in the supplemental attachment to the Original RPIP.[12] PGE notes that the 175 MWa addition is consistent with plans for an RFP the Company originally planned, which would have targeted the procurement of some resource(s) that would have begun operation in 2018.[13] However, if this resource had been successfully procured, it would have never contributed to RPS compliance through the 2021 because PGE would have received and subsequently banked the unlimited-life RECs, or "Golden RECs," generated from this resource. Therefore, it bears no impact on the incremental costs later calculated by the Company per the existing administrative rules.

Finally, a more notable change between PGE's Original and Revised RPIPs is the significant decrease in incremental costs the Company forecasts through 2021. Table 1, below, highlights the differences in incremental cost and associated percentage of revenue requirement between the base case in the Original RPIP and the base case for the "Staged Build-Diverse" scenario:

[12] PGE's Supplemental Attachment A, "Tab 2 – Incremental Cost for RECs Generated," Docket No. UM 1755, February 16, 2016.
[13] PGE's 2016 Revised RPIP, at page 5, Docket No. UM 1788, July 15, 2016.

Table 1: Comparison of Incremental Costs between Original RPIP and Revised RPIP

| Base Case: RefGas–RefCO2 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Original – Incremental Cost ($) | 65,586,177 | 61,798,289 | 54,159,310 | 75,957,977 | 77,101,851 |
| Original – Revenue Requirement ($000) | 1,805,242 | 1,849,798 | 1,892,835 | 1,938,338 | 2,007,923 |
| Original - % of Rev. Req. | **3.6** | **3.3** | **2.9** | **3.9** | **3.8** |
| Revised – Incremental Cost | 30,383,341 | 30,727,685 | 31,305,826 | 46,635,246 | 48,443,604 |
| Revised – Rev. Req. ($000) | 1,886,948 | 2,047,619 | 2,081,500 | 2,116,258 | 2,180,847 |
| Revised- % of Rev. Req. | **1.6** | **1.5** | **1.5** | **2.2** | **2.2** |
| Difference in percentage | **2.0** | **1.8** | **1.4** | **1.7** | **1.6** |

In Docket No. UM 1755, Staff and the Industrial Customers of Northwest Utilities (ICNU) noted the alarming proximity PGE's base case had to the four percent cost cap.[14] From Staff's analysis and investigation, a combination of lower levelized costs for wind resources due to much lower variable resource integration costs, higher costs for the proxy combined cycle combustion turbines, and the elimination of the "first-in, first-out" REC retirement requirement results in the substantially lower incremental costs in the Revised RPIP.

Below, Table 2 provides the comparison of incremental cost data, the annual revenue requirement, and the percentage of total cost for the "Staged Build – Diverse" scenario and the same scenario with maximum use of unbundled RECs; the Company uses a cost of $0.54 per unbundled REC.[15]

[14] Other scenarios in PGE's Original RPIP met or exceeded the four percent cost cap.
[15] This value derives from the 2014 Compliance Report in UM 1740 and the methodology prescribed in Commission Order No. 14-265.

Table 2: Incremental cost calculations for bundled and unbundled REC sensitivities

| **Base Case: RefGas–RefCO2** | **2017** | **2018** | **2019** | **2020** | **2021** |
|---|---|---|---|---|---|
| Total Incremental Cost without unbundled RECs ($) | 30,383,341 | 30,727,685 | 31,305,826 | 46,635,246 | 48,443,604 |
| Total Incremental Cost with 20% unbundled RECs ($) | 14,972,626 | 36,435,577 | 31,158,257 | 37,708,588 | 25,807,652 |
| | | | | | |
| Incremental cost difference for 20% unbundled compliance | 15,410,715 | -5,707,892 | 147,569 | 8,926,658 | 22,635,952 |
| Incremental cost difference for 20% unbundled compliance (%) | 50.7 | -18.6 | 0.0 | 19.1 | 46.7 |
| | | | | | |
| **Percentage of Rev Requirement (w/o unbundled) (%)[16]** | **1.6** | **1.5** | **1.5** | **2.2** | **2.2** |
| **Percentage of Rev Requirement (w/ 20% unbundled) (%)** | **0.8** | **1.8** | **1.5** | **1.8** | **1.2** |
| **Difference in Percentage** | **0.8** | **-0.3** | **0.0** | **0.4** | **1.0** |

The results of this comparison show lower compliance costs for three years and higher compliance costs for one year. Given PGE's heuristic REC retirement methodology and the fact that unbundled RECs can be banked, Staff believes that these results do not reflect the overall lower compliance RPS costs that can be achieved through more active REC bank management.

PGE indicates from the data and explanations found in the Revised RPIP that the Company will successfully comply with the RPS annually in the years 2017 – 2021.

PGE's Plan to Comply with the RPS through 2040

PGE's long-term RPS compliance narrative focuses largely on the Company's interpretation of the trade-off analysis embodied in question number three of Staff's five questions. In its attempt to construct an evaluation of near-term resource acquisition that may reduce overall costs to ratepayers as opposed to acquiring resources to meet a system or RPS need, PGE models four scenarios consisting of different types of resources and timing of acquisition that all procure in total 1,045 MWa in new resources by 2040.

[16] Revenue requirement for the scenario without unbundled RECs is about $30 million higher starting in 2018. The numbers shown above use the scenarios respective revenue requirements; using the lower of the two results in approximately 0.1 percentage increase for the scenario without unbundled RECs in 2021.

The Company creates two resource acquisition categories called "staged build" and "utilized bank."[17] In order to meet the RPS requirements at the increasing intervals, the "staged build" category acquires 228 MWa in 2030 and 2035, while acquiring 376 MWa to achieve physical compliance in 2040. The "utilized bank" scenario "defers resource acquisition in 2030 to 2035 to the extent possible while maintaining the minimum recommended REC bank level;" this scenario procures only 43 MWa in 2030, 598 MWa in 2035, an 191 MWa in 2040.[18] The "minimum recommend REC bank level," which informs the 1,045 MWa acquisition goal in 2040 for all scenarios, is neither explained nor justified in the main narrative, an element of the Revised 2016 RPIP that Staff finds extremely troubling and is further explored later in this memorandum.

Within each of those categories are two scenarios that contemplate different types of resource procurement: strictly wind resource acquisitions, where all resources have characteristics of a "Columbia River Gorge wind resource," or "diverse" renewable resources that contain wind resources early and single-axis tracking solar in later years.[19] The result of four-scenario analysis is the following incremental cost data in Table 3:

Table 3: Incremental Cost/(Benefit) by Year ($mil)

| Year | Staged Build-Diverse | Utilized Bank-Diverse | Staged Build – All Wind | Utilized Bank – All Wind |
|---|---|---|---|---|
| 2020 | 46.6 | 46.6 | 46.6 | 46.6 |
| 2025 | 37.7 | 37.7 | 37.7 | 37.7 |
| 2030 | 59.2 | 76.1 | 45.8 | 80.3 |
| 2035 | 59.1 | 27.8 | 30.7 | (12) |
| 2040 | 20.8 | 29.1 | (27.4) | (28.1) |

This trade off analysis does not evaluate the accelerated near-term acquisition opportunity that was a major motivator for Staff requiring new RPIPs for both utilities. PGE does not contemplate an analysis of the presumed 175 MWa of wind resources. For all intents and purposes of the Revised 2016 RPIP, it's a forgone conclusion; PGE states that it "has found the benefits of capturing federal tax credits before they decline or expire exceed [the potential for future technology cost reductions and the time value of money]."[20] PGE provides no quantitative evidence to substantiate this claim in the Revised 2016 RPIP.

[17] PGE's 2016 Revised RPIP, at page 5, Docket No. UM 1788, July 15, 2016.
[18] Ibid. at pages 5-6.
[19] Ibid. at page 6.
[20] Ibid., at pages 4-5.

Some parts of the analysis that Staff requested are only met with acknowledgement and a brief verbal explanation in the Revised RPIP, such as the market assumptions analysis or the unbundled REC tipping point analysis. The Company pointed to the analysis being done in its pending 2016 IRP as a reason to explain the deficiencies in analysis contained in its Revised RPIP.[21] PGE notes early in the Revised RPIP that "some of the questions posed by the Commission [in the unopposed motion] are very in-depth and require extensive and thorough analysis in an IRP."[22] After presenting the incremental costs found in Table 3, PGE notes that "this calculation neglects important cost components that impact customers and are evaluated in the IRP."[23]

Regarding unbundled RECs, PGE "strongly asserts that it is both strategically detrimental and highly hypothetical to forecast REC prices and purchases."[24] PGE attributes the lack of an organized market and increasing uncertainty in REC markets due to increasing RPS requirements in WECC-member states as reasons for its position that unbundled RECs should be "a compliment to a physical compliance strategy" rather than a primary one.[25] Requiring the Company to use the maximum 20 percent of unbundled RECs could affect the market, resulting in cost-ineffective compliance decisions. Rather, PGE supports the flexibility in periodically checking the REC market in order to determine the "financial feasibility of using unbundled RECs in any particular year."[26] More importantly, PGE believes that physical compliance, ideally through utility-owned resources, is the optimal RPS compliance strategy.

<u>Stakeholder Comments</u>
Renewable Northwest and Oregon Solar Energy Industries Association filed joint comments (RNW/OSEIA). Additionally, Northwest Energy Coalition (NWEC), and ICNU each filed comments. Their and Staff's comments are summarized below by general topic; PGE's reply comments, where available, are included.

*Physical Compliance vs. Unbundled RECs*

RNW/OSEIA and NWEC agree that an unbundled REC-based compliance strategy is more risky than a physical resource compliance strategy. These parties agree with PGE's assertion that the unbundled REC market is too uncertain and volatile to support unbundled RECs as a sustained RPS compliance strategy. RNW/OSEA add:

[21] The 2016 IRP was file November 15th, 2016.
[22] PGE's 2016 Revised RPIP, at page 3, Docket No. UM 1788, July 15, 2016.
[23] Ibid., at page 7.
[24] Ibid., at page 10.
[25] Ibid.
[26] Ibid.

> several factors are expected to put upward pressure on the REC market in the next few years, including increasing RPS targets in the West, increasing customer participation in voluntary renewable energy programs Clean Power Plan implementation and other potential carbon policies.[27]

These parties instead support a RPS compliance strategy that relies primarily on physical renewable resources due to the resulting benefits to customers in the form of reduced risk and lower costs. RNW/OSEIA emphasizes how features of SB 1547, such as REC bank hedging, are enhanced by the recently extended federal production tax credits (PTC) and investment tax credits (ITC). NWEC notes that additional analysis to support PGE's position "would...illustrate the quantitative risks posed by a reliance on unbundled RECs."[28]

ICNU, in noting that PGE did not comply with Staff's request to conduct a tipping-point analysis regarding the cost of unbundled RECs versus a physical resource acquisition, provides its own tipping-point analysis that was originally developed in response to the Company's proposed RFP.[29] ICNU's analysis demonstrates:

> that a strategy of relying on unbundled RECs would push out the Company's need for physical resources until 2030 and save customers at least $540 million on a present value revenue requirement basis relative to the Company's' early physical compliance strategy.[30]

Replicating this analysis in its comments in this case, ICNU calculates that the unbundled REC price would have to exceed $40.00 in order for physical compliance to be cost effective when considering the addition of 175 MWa in 2018. Based on this analysis, ICNU finds PGE's reluctance to forecast unbundled REC market prices "irrelevant" because the Company would have the value at which unbundled RECs are cost effective.[31] Even though ICNU's included analysis is high-level, the resulting tipping-point cost is substantially higher than any unbundled REC purchase PGE has made and even higher than "energy on the market."[32]

Furthermore, ICNU finds PGE's proposed RPS compliance strategy problematic because even though the Company does not forecast utilizing unbundled RECs for compliance, it historically has done so up to the maximum 20 percent. In turn, PGE will likely over-comply with the RPS because it will plan for a higher physical compliance

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[27] RNW/OSEIA Joint Comments, at page 3, Docket No. UM 1788, September 12, 2016.
[28] NWEC Comments, at page 3, Docket No. UM 1788, September 12, 2016.
[29] *See* ICNU Supplemental Comments, Docket No. UM 1773, June 28, 2016.
[30] ICNU Comments, at page 7, Docket No. UM 1788, September 12, 2016. ICNU notes that this cost does not include the carry-forwards costs associated with the PTC.
[31] ICNU Comments, at page 10, Docket No. UM 1788, September 12, 2016.
[32] Ibid.

target than actually needed. ICNU notes that PGE's hesitation to pursue unbundled RECs because of speculation in an organized market goes both ways; similar speculation exists in a complete physical compliance strategy that relies on the assumption the Company will *not* be able to buy unbundled RECs in the future.

Relatedly, ICNU recommends that PGE pursue RECs in addition to physical resources when it seeks near-term procurement. To emphasize the benefits of pursuing RECs as well as physical resources, ICNU highlights the results of PacifiCorp's 2016 REC request for proposals (RFP), which resulted in PacifiCorp only procuring RECs, rather than a physical resource. ICNU identifies the existing opportunities PGE can access to secure RECs, including current QF contracts and the upcoming thermal RECs. ICNU references discovery as well to counter PGE's claim that RECs are trading at a "significant premium to current market prices in PacifiCorp's RFP," a position which ICNU notes is "unclear and undocumented."[33]

In response to ICNU's tipping-point analysis, PGE provides its own analysis, sourced from the 2016 IRP, that indicates the tipping point for unbundled RECs is approximately $15 per REC.[34] This analysis also shows that foregoing wind procurement at the 100 percent PTC level because of unbundled REC usage while also "maintaining the recommended minimum REC bank balance" may not result in the least-cost outcome.[35] PGE also contends that ICNU's own tipping-point analysis is flawed because it apparently relies on the assumption of sufficient REC supply through 2070, which PGE contends is not a tenable near-term strategy. PGE continues to question the "appropriateness of developing a long-term resource plan that relies on a resource for which there is no supply-certainty."[36] Because of the uncertainty of the REC market, PGE states that any cost-effective decision regarding REC procurement must be made at time of procurement rather than in advance. PGE reiterates its previous comments and other RNW/OSEIA's, stating upward pressure from regional forces, like growing RPS requirements, will result in growing uncertainty.

*2017 – 2021 RPS Implementation and Compliance*

Staff and ICNU find significant issue with the assumed presence of the 175 MWa wind resource acquisition in 2018. Because the Revised RPIP does not analyze alternative near-term compliance opportunities, ICNU finds the Revised RPIP fails to comply with the least-cost/least-risk directive of Staff's five questions and "is not even a starting point for the evaluation of a prudent RPS compliance plan."[37] Staff's concerns begin

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[33] Ibid., at page 14.
[34] PGE's Reply Comments, at page 20, Docket No. UM 1788, November 7, 2016.
[35] Ibid.
[36] Ibid., at page 21.
[37] ICNU Comments, at page 6, Docket No. UM 1788, September 12, 2016.

before the five questions are even contemplated: the 175 MWa proposed acquisition is even larger than the one that was found in the supplemental attachment to the Original RPIP, which was Staff's main impetus for requiring a new RPIP. Staff in its initial comments quoted a passage from PGE's 2013 IRP update; it bears repeating:

> *However, for the reasons cited throughout this chapter, a number of factors represent risks that may require PGE to rely on the current REC bank in future periods, including the potential for Oregon's RPS targets to increase materially relative to the targets currently in place. Based on these factors PGE intends to maintain a minimum REC bank balance of 300-600 MWa. Based on a minimum REC bank balance of 300-600 MWA,* ***PGE concludes a physical renewable resource addition in 2024, balanced by reliance on banked RECs through 2023, enables PGE to delay costs of physical compliance in 2020.*** *This strategy provides a hedge against factors that pose future cost or compliance risks for PGE.* [38]

Staff noted that "SB 1547 did not change the RPS compliance for 2020 and only increased the RPS compliance for 2025 from 25 percent to 27 percent."[39] Despite the near-term RPS consistency and PGE's previous position of deferral, the Company is pursuing 175 MWa of physical resources in 2018 presumably to only capture federal tax incentives. The concern in response to this about-face change in resource procurement strategy is even stronger given ICNU's calculation that shows a physical compliance strategy may not be the most cost-effective way to comply with the RPS in the near-term. Unfortunately, Staff is unable to determine what indeed might be cost-effective because PGE did not endeavor to conduct the requisite quantitative analysis in the Revised RPIP.

Staff also listed the concerns it had with the lack of quantitative analyses and visualizations throughout the Revised RPIP, specifically the absence of data an methodologies supporting "variables, assumptions, or calculations…."[40] Staff also touched on the heuristic REC retirement strategy the Company employs and how that has the potential for creating higher incremental costs because of older, less costly RECs being retired first. RNW/OSEIA stated they felt important data was marked confidential when it may have not been necessary given what PacifiCorp filed in its respective RPIP docket.

ICNU argues that PGE should be using a more flexible firming resource in determining the proxy combined cycle combustion turbine (CCCT) unit, such as the Company's own Port Westward 2 plant (PW2) or a more flexible simple cycle combustion turbine

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[38] PGE's 2013 IRP Update, at page 60, Docket No. LC 56, December 2, 2016. (emphasis added)
[39] Staff's Comments, at page 3, Docket No. UM 1788, September 12, 2016.
[40] Staff's Comments, at page 6, Docket No. UM 1788, September 12, 2016.

(SCCT), rather than a "bare-bones frame" SCCT. In addition to restating one of PGE's reasons for installing PW2, to deal with the variability of wind output, ICNU also mentions the NWPCC's Seventh Power plan's discussion of flexible resources used to integrate variable generation.

In response to ICNU's firming resource recommendation, PGE refers to Commission Order No. 14-034, which contains a stakeholder-agreed methodology that addresses the characteristics of the firming SCCT in dispute. PGE contends that ICNU's desired methodology, which would create capacity equivalence with the proxy CCCT, directly contradicts the language in the order, which requires equivalence with the *RPS resource*. PGE adds that its "analysis includes an estimation of variable resource capacity contribution based on an effective load carrying capacity methodology… consistent with PGE's 2016 IRP."[41] The Company holds firm that "the fixed costs of either the more expensive reciprocating engine or aeroderivative technologies [that ICNU advocates for] may be an appropriate measure of the cost of *flexible* capacity."[42]
*Incremental Costs*

ICNU continues to recommend utilities calculate incremental cost on *delivered* qualifying power (i.e. RECs *generated*), not power associated with RECs *retired* in any given compliance year. ICNU contends that the existing incremental cost methodology that relies on RECs retired is not capturing the actual costs borne to ratepayers and is contravening applicable Oregon law. An illustrative example is found in PGE's 2015 RPS compliance report, which shows that despite PGE's Tucannon wind farm currently being paid for by customers, the wind resource does not contribute to current incremental costs because its RECs are banked for future use.[43]

ICNU proceeds to navigate the legal points of both its position and PGE's response to it. Staff, for the sake of brevity, notes its refinement and importance but leaves readers to explore its entirety in the originating comments.[44] Based on its analysis of the RPS legal provisions, ICNU recommends the Commission require the Company calculate its incremental cost based on the RECs generated.

Staff raises similar concerns regarding the incremental cost methodology being disconnected from the actual costs ratepayers are subject to, but focuses on the existence of "Golden RECs" to underscore the issue rather than existing REC matters like ICNU does. Whereas under the "first-in, first-out" rule, a REC would be retired eventually, a REC under the SB 1547 compliance scheme may never be retired. Staff

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[41] PGE's Reply Comments, at page 18, Docket No. UM 1788, November 7, 2016.
[42] Ibid., at page 19/
[43] *See* ICNU's comments, Docket No. UM 1783, July 15, 2016.
[44] ICNU Comments, at pages 14-18, Docket No. UM 1788, September 12, 2016.

highlighted that PGE's REC accounting may result in some RECs remaining in the bank through the 2030s.

As stated in related dockets, PGE calculated the incremental costs of RPS compliance in accordance with existing administrative rules – the Company argues that it cannot unilaterally calculate the values in the way ICNU requests. PGE points to Staff comments in Docket No. UM 1783 which include Staff's belief that the time is ripe for revisiting the incremental cost methodology. PGE supports revisiting the incremental cost methodology in the likely forthcoming RPS rulemaking. However, PGE notes that it essentially has complied with ICNU's requests in recent RPIPs; the second tab of the Company's analyses calculates incremental costs of RECs generated.

*RPIP Process*

NWEC, RNW/OSEIA and Staff agree that revisions to the RPIP process are needed in light of changing legal, regulatory and market dynamics. Recommendations for stakeholders include tying RPIP analysis to utility events, such as an acknowledged IRP; expansion of RPIP analysis and process to include longer planning periods, and ways to integrate aspects of the RPIP into the existing IRP framework. This last point is particularly salient given Staff's dissatisfaction with the lack of certain analyses in the Revised RPIP that PGE justified as having been included in its 2016 IRP.

PGE indicates support for improving the RPIP process, such as better aligning the RPIP with the Company's IRP timeline, utilizing resource portfolios identified in the IRP, or even incorporated into the IRP as an appendix.

<u>Staff's Analysis</u>

Though Staff appreciates the additional information provided in the Company's Reply Comments, issues with the Revised RPIP as well as now filed 2016 IRP leave Staff in a position unable to recommend acknowledgement without conditions. Because PGE's 2017 – 2021 RPS Compliance strategy successfully meets the statute and rules, Staff recommends the Commission acknowledge the revised 2017-2021 RPIP component with the condition that PGE furnish additional analysis and information. However, Staff recommends the Commission not acknowledge the Company's responses to Attachment A of Commission Order No. 16-157, where the concerns expressed in this memorandum derive.

Because PGE failed to adequately conduct the full analysis required in the five questions provided in Attachment A, the Company does not demonstrate that its proposed qualifying resource acquisition strategy meets the least-cost, least-risk principles over the 2040 planning horizon. The Company's decisions presented in the

Revised RPIP provide no basis for Staff to conclude that the Company has exhaustively explored the least-cost, least-risk methods of compliance.

Staff identifies items below that demonstrate the critical issues it has with the Revised RPIP. They are not exhaustive of the range of issues Staff had with the Revised RPIP. Rather, they are a selection of critical issues that support Staff's recommendation for additional information and analysis. Furthermore, Staff identifies high-level areas of new or updated analysis that it requests be included in a supplemental filing by PGE in this docket. To ensure that a successful and comprehensive analysis is conducted, Staff will recommend the Commission direct all stakeholders meet shortly after the special public meeting in order to ensure all analysis parameters are agreed upon and that the scope of the new work is supported by all stakeholders.

1. PGE's 2016 IRP is now available

Throughout the Revised RPIP, stakeholder comments, and PGE's Reply Comments, concerns and issues that arise from the mismatched timing of PGE's Revised RPIP and the Company's 2016 IRP are ubiquitous. Much of Staff's and stakeholder's analyses were conducted on information that was either tentative or unknown until PGE filed its 2016 IRP on November 15, 2016. While PGE was able to provide some of the IRP analysis in its Reply Comments, the volume of information and data provided requires additional time for sufficient analysis. Using the information provided in the newly filed 2016 IRP along with the Company's information provided in the Revised RPIP and its Reply Comments, Staff adjusts the five questions and establishes a clear reporting framework and expectations to facilitate Staff's pursuit of PGE's long-term RPS compliance strategy.

2. Minimum REC Bank

Staff believes the minimum REC bank that justifies the Company's overall RPS compliance strategy is artificially inflated to the extent that it may result in significant over-build and subsequently unnecessary costs to customers. PGE has stated in conversations with Staff as well as in discovery that reasons for having such a high REC bank minimum include higher-than-forecasted load growth, lower-than-forecasted renewable generation, and the failure of a renewable resource RFP. In a response to a discovery request by ICNU, PGE asserts that it will need approximately 406 MWa in a minimum REC bank during the 2025-2029 period, and ultimately up to 730 MWa in 2040. The latter amount results in more than half of what PGE will need to successfully comply with its forecasted RPS load in 2040, a risk position that Staff finds extremely troubling giving the renewable resources required to generate that amount of RECs.

Though these reasons may be valid, Staff believes the scope and probability of each of them does not warrant the high minimum REC bank and therefore requires additional scrutiny and analysis. Furthermore, PGE does not provide substantive quantitative analysis, including a robust trade-off analysis or REC bank management analysis that supports such a substantial REC bank. Therefore, in the requested analysis, Staff will focus on this value and how it affects all aspects of PGE's RPS compliance over the 2040 horizon.

3. Banked "Golden RECs"

Regarding banked "Golden RECs," the Company's forecasted compliance strategy indicates it will continue to bank these well into the 2030s. The quantity available to the Company after compliance with the 2015 RPS is substantially voluminous that without robust and exhaustive trade-off analyses that were originally requested, Staff does not believe PGE is representing its best efforts in complying with the RPS in a way that achieves least-cost, least-risk with ratepayers.

4. Deficient quantitative and qualitative analyses

Some requests in the five questions were not comprehensively explored by PGE in the Revised RPIP, such as market assumptions, trade-off analyses comparing just-in-time acquisition with near-term resource procurements, and the impact of purchased RECs on PGE's RPS compliance position. Furthermore, Staff believes that PGE did not transparently identify, model and justify the Company's long-term RPS obligation, which would provide important context for any compliance action through 2040. Without a clear need, any presented compliance strategy is met with skepticism. Staff and stakeholders will work with PGE to clarify and refine the quantitative analyses so that the Company's responses address Staff's expectations.

Staff recommends the Commission direct PGE to conduct three distinct tasks. First, the Company is to respond to an updated version of the five questions that were originally posed in the unopposed motion now that the Company is able to exhaustively complete a narrative with accompanying analysis. Second, the Company is to conduct a set of additional quantitative analyses that evaluates the Company's RPS compliance strategies over the 2040 timeframe. Both of these tasks are to be conducted within Docket No. UM 1788 and filed with the Commission by May 1, 2017. Third, the Company is to participate in a workshop with stakeholders to determine the details of the requested analyses.

The 2016 RFPs, SB 1547 and the federal tax credit extension reveal the limits of the existing RPIP process. First, as stakeholders pointed out, the requirement that a utility file biannually may no longer be the appropriate determination of an RPIP filing. Two years plus the six months allowed for Commission review create a regulatory blind spot during which utilities could feasibly acquire qualifying renewable resources that were not forecasted in a previous IRP or RPIP. With the growing role of "economic need" in utility resource planning coupled with the doubling of the RPS by 2040, a significant amount of capacity could be bid, reviewed, accepted and partly constructed before the Commission would be able to determine if such a resource acquisition remained under the statutory four percent cost cap.[45]

Such planning-asynchronous resource acquisitions were previously rare, but SB 1547's opportunity for "Golden RECs" over the next decade coupled with unpredictable market dynamics invite the possibility of unplanned renewable resource procurement. Due to this new paradigm, changes to the RPIP process are in order to ensure the statutory safeguards regarding RPS compliance are effectively enforced.

Until structural changes to the RPIP process can be implemented in the upcoming RPS rulemaking, Staff recommends the Commission require PGE to conduct the following actions when it commences an early-action resource procurement or deviates from the most recently filed RPIP or IRP that may ultimately result in a physical resource or REC acquisition for the purposes of complying with the RPS:

a. Demonstrate the forecasted benefit to ratepayers if the resource or resources do not immediately satisfy a system capacity or RPS need;
b. Explain the interaction the new resource or resources have with the most recently filed IRP or RPIP;
c. Calculate new incremental costs with the new resource or resources included across twenty years;
d. Respond to requests by the Commission regarding its new analysis arising out of the calculation set forth in 1(c) above; and
e. Participate in a stakeholder workshop to identify opportunities for revisions to the RPIP process and requirements.

Staff presented the same concern and set of recommendations in Docket No. UM 1790, PacifiCorp's Revised 2017 – 2021 RPIP. No doubt additional changes to the RPIP process are needed as all stakeholders across both utilities' respective RPIP and RPS compliance reporting processes have identified. Staff believes this docket is not the appropriate venue for the Commission to determine these changes; however, the upcoming RPS rulemaking is.

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[45] "Economic need" does not represent a system capacity "need" established in IRPs nor does it reflect the additional value a qualifying facility is afforded in avoided cost rates during an insufficiency period. Rather, it captures a "time-limited resource" that is only seen in exemptions to the Commission's bidding guidelines.

Staff believes a RPIP process workshop prior to the RPS rulemaking will enable stakeholders to begin identifying the deficiencies and concerns of the existing RPIP rules. Therefore, Staff recommends the Commission direct the utility to participate in a workshop in order to facilitate the upcoming rulemaking.

*Conclusion*

Staff concludes that PGE has met the requirements of OAR 860-083-0400 and ORS 468A.075, and therefore recommends that the Commission acknowledge the Company's Revised RPIP, albeit with conditions. Staff concludes that PGE has not answered the supplemental requirements found in Commission Order No. 16-157 in a satisfactory or acceptable manner, and therefore recommends the Commission not acknowledge the supplemental attachment responses. Staff further recommends that the Commission require PGE to do the following:

1. Respond to a modified set of supplemental questions and quantitative analyses regarding its long-term RPS compliance strategies;
2. Meet with Staff and stakeholders to determine the specifics of the aforementioned questions and analyses.
3. Participate in a separate stakeholder workshop to identify opportunities for revisions to the RPIP process and requirements.

Additionally, Staff also recommends that the Commission require PGE to comply with the following steps when it commences a resource procurement action for the purpose of complying with the RPS prior that materially deviates from its most recently filed IRP or RPIP:

a. Demonstrate the forecasted benefit to ratepayers if the resource or resources do not immediately satisfy a system capacity or RPS need;
b. Explain the interaction the new resource or resources have with the most recently filed IRP or RPIP;
c. And, calculate new incremental costs with the new resource or resources included across twenty years.
d. Respond to any additional requests by the Commission regarding new analysis.

**PROPOSED COMMISSION MOTION:**

Acknowledge PGE's Revised 2016 Renewable Portfolio Standard Implementation Plan along with Staff's recommendations set forth immediately above in the "Staff Recommendation" part of this memorandum, while not acknowledging the supplemental attachment found in Commission Order No. 16-157.

## Attachment A

The following are the five questions found in Attachment A of Commission Order No. 16-157.

1. A discussion of the differences between SB 838 (i.e. ORS 469A.005 to ORS 469A.210) and SB 1547, with a supporting analysis demonstrating the impacts of those differences on utility planning and operations decisions 2017-2040.

2. An analysis of these aspects of SB 1547: its elimination of the "first in, first out" requirement, its creation of unlimited REC life status for the first 5 years of new resources acquired between 2016-2022, its shortening of the standard Renewable Energy Credit (REC) life, and the steep compliance rate increase between 2025 and 2030. In particular, the analysis should address how these aspects of SB 1547 affect how the utility plans to optimize the mix of compliance RECs for least cost and lowest risk.

3. A discussion of how the timing of new renewable resource acquisitions impact long term cost of compliance with the RPS to ratepayers with supporting analysis demonstrating these differences in timing. Under what conditions does the least cost/lowest risk strategy to satisfy the RPS compliance requirements of SB 1547 from 2017 through 2040 lead to new resource acquisition prior to a physical need and how will the utility evaluate this decision? PGE should provide a "tipping-point" analysis that depicts when physical resource acquisition is more cost effective than buying unbundled RECs.

4. A discussion of how key market assumptions impact the relative range of risk and uncertainty related to cost over the compliance horizon. Load growth, hydroelectric generation, project cost, natural gas and electricity market prices are some examples of key assumptions to be assessed in this discussion.

5. Throughout the analysis, PGE should provide methodologies and assumptions used to support the RPIP along with a narrative describing the reasoning behind the selection of those methodologies and assumptions.