PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 18, 2016

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

Re: Docket UM 1754—PacifiCorp's Reply Comments

PacifiCorp, d/b/a Pacific Power (PacifiCorp or the Company) respectfully submits these comments in response to the comments of Public Utility Commission of Oregon (Commission) Staff, Industrial Customers of Northwest Utilities (ICNU) and Small Business Utility Advocates (SBUA) on PacifiCorp's 2017-2021 Renewable Portfolio Implementation Plan (2017-2021 RPIP). PacifiCorp filed its 2017-2021 RPIP on December 29, 2015.

I. Background

The renewable portfolio implementation plan (RPIP) serves two primary purposes. First, the RPIP forecasts the utility's renewable portfolio standard (RPS) compliance position and strategy. This function of the RPIP is done consistent with the utility's integrated resource plan (IRP) and, similar to the IRP, the RPIP shows the position and strategy for a forecasted future time horizon. The assumptions in the RPIP are the same as the assumptions from the 2015 IRP, acknowledged on February 29, 2016, updated with more current load forecasts and any relevant changes to the Company's portfolio of Oregon RPS-eligible resources. Unlike the IRP, however, the RPIP is not intended to result in resource acquisition decisions; the IRP remains the forum for analyzing resource needs.

Second, the RPIP presents the calculation of the utility's incremental cost of compliance with the RPS. Importantly, the incremental cost calculation does not reflect the actual cost to customers for complying with the RPS, but rather a forecast of the difference between what the utility anticipates spending to achieve RPS compliance and costs the utility could incur absent a RPS. Although the Company presents its cost of RPS compliance in its RPIP, the Commission does not make cost-recovery decisions as part of its acknowledgment. In this regard, the RPIP is similar to the IRP in that the Commission's acknowledgment, or lack of acknowledgment, is not dispositive of the prudence of the investment. Indeed, the Commission's role in acknowledging the RPIP is not to determine whether any specific compliance actions are appropriate for cost-recovery, but to determine whether the utility's RPIP is consistent with the reporting requirements of ORS 469A.075 and the Commission's rules.

Fundamentally, the RPIP allows the Commission and stakeholders to see how the results of the Company's last acknowledged IRP, including resource needs, translate into an RPS compliance strategy and to see whether the costs of RPS compliance are approaching the four percent cost cap contained in ORS 469A.100. Resource need analysis and cost-recovery decisions are not, and should not be, part of the RPIP.

II. Response to Comments

a. Comments of Staff

Staff identified the following areas for additional clarification from the Company: (1) the inclusion of the Black Cap solar facility in the incremental cost calculation; (2) the Company's bundled versus unbundled REC compliance strategy, and (3) the duration of the Company's REC bank.

Resources Included in Compliance of OAR 860-083-0400(2)(d) - Black Cap

OAR 860-083-0100(13)(a)[1] and (b)[2] authorize a utility to exclude certain qualifying electricity from the incremental cost calculation, provided the total amount of qualifying electricity excluded stays below certain thresholds: 20 megawatts (MW) of capacity in a single compliance year or 50 MW of cumulative capacity. Once the threshold is triggered, "the incremental cost of all such qualifying electricity must be included in the compliance report for the compliance year and in compliance reports and implementation plans filed after such compliance report."

Per the exclusion authorized in OAR 860-083-0100(13)(a), the Company did not include the Black Cap project in previous incremental cost calculations. Beginning with 2016, however, the Company's cumulative capacity associated with excluded qualifying resources is anticipated to exceed the 50 MW threshold. As a result and consistent with OAR 860-083-0100(13)(b), the

[1] OAR 860-083-0100(13)(a) reads in full: Except as provided in section (11) of this rule, if new long-term qualifying electricity in a compliance year, including qualifying electricity treated in the same manner as new qualifying electricity in subsections (4)(b) and (6)(g) of this rule, totals less than 20 megawatts of capacity, the incremental cost for such long-term qualifying electricity is not required to be included in compliance reports or implementation plans. Such long-term qualifying electricity may be included in a compliance report for purposes of determining compliance with the applicable renewable portfolio standard under ORS 469A.052 or ORS 469A.065. term qualifying electricity in a compliance year, including qualifying electricity treated in the same manner as new qualifying electricity in subsections (4)(b) and (6)(g) of this rule, totals less than 20 megawatts of capacity, the incremental cost for such long-term qualifying electricity is not required to be included in compliance reports or implementation plans. Such long-term qualifying electricity may be included in a compliance report for purposes of determining compliance with the applicable renewable portfolio standard under ORS 469A.052 or ORS 469A.065.

[2] OAR 860-083-0100(13)(b) reads in full: When the capacity of qualifying electricity described in subsection (13)(a) of this rule equals or exceeds 20 megawatts in a compliance year or the cumulative capacity of qualifying electricity in subsection (13)(a) of this rule exceeds 50 megawatts, the incremental cost of all such qualifying electricity must be included in the compliance report for the compliance year and in compliance reports and implementation plans filed after such compliance report.

Company is now including all qualifying electricity previously-excluded per OAR 860-083-0100(13)(a) in the incremental cost calculation, including Black Cap.[3]

The inclusion of the Black Cap Solar facility does not have a significant impact to the incremental costs in the 2017-2021 RPIP. The tables below demonstrate the impact of including Black Cap in the 2017-2021 RPIP.

	Scenario 1 - 2015 IRP Base Case				
	2017	2018	2019	2020	2021
Incremental Costs with Black Cap	$ 6,720,530	$ 6,782,698	$ 6,793,123	$ 9,131,889	$ 9,204,673
Incremental Costs without Black Cap	$ 6,639,921	$ 6,701,376	$ 6,711,617	$ 9,022,045	$ 9,094,660
Difference	$ 80,609	$ 81,321	$ 81,507	$ 109,844	$ 110,013
Difference (%)	1.20%	1.20%	1.20%	1.20%	1.20%
	Scenario 7 - Nov 9, 2015 OFPC Fuel Curve				
	2017	**2018**	**2019**	**2020**	**2021**
Incremental Costs with Black Cap	$ 15,672,235	$ 15,831,134	$ 15,830,430	$ 21,192,469	$ 21,241,627
Incremental Costs without Black Cap	$ 15,559,444	$ 15,717,346	$ 15,716,383	$ 21,038,772	$ 21,087,692
Difference	$ 112,791	$ 113,788	$ 114,047	$ 153,697	$ 153,934
Difference (%)	0.72%	0.72%	0.72%	0.73%	0.72%

Unbundled versus Bundled REC Strategy

Staff presented a table showing that under the base case scenario, maximizing use of unbundled RECs during the 2017-2021 compliance period results in a nearly 50 percent decrease in incremental cost.[4] Based on this, Staff recommends that PacifiCorp give greater consideration to an unbundled REC compliance strategy.[5] In reviewing Staff's comments, PacifiCorp discovered an error in the presentation of the levelized costs under the sensitivity which maximizes the use of unbundled RECs during 2017-2021.[6]

Staff is correct that an unbundled REC strategy is less expensive than one that assumes the use of only bundled RECs; however, using the corrected bundled REC pricing, the use of unbundled RECs versus compliance using only bundled RECs results in a cost differential of only 15.82 percent to 19.16 percent, and not 50 percent. The table below provides a corrected comparison of RPS compliance with and without the 20 percent unbundled RECs during the 2017-2021 period.

---

[3] In addition to Black Cap, the 2017-2021 incremental cost calculation included the following resources under development and expected to be qualifying resources: Latigo Wind – 60 MW, Pioneer Wind – 80 MW, and Pavant II Solar – 50 MW. The calculation also added the previously-excluded Oregon Solar Incentive Program.
[4] Initial Comments of Staff at 2.
[5] Initial Comments of Staff at 3.
[6] On Table 7 (pg. 14) of the RPIP, the levelized incremental cost of bundled RECs was understated. This resulted in decreased total incremental costs under the 20 percent unbundled REC sensitivity. These figures were correctly presented in supporting Workpaper 02, Total Compliance Cost, but were not updated in Table 7 of the 2017-2021 RPIP.

Base Case (RefGas-RefCO2)	2017	2018	2019	2020	2021
Total incremental costs without unbundled RECs ($000s)	$6,721	$6,783	$6,793	$9,132	$9,205
Total incremental costs with 20% unbundled RECs ($000s)	$5,658	$5,710	$5,719	$7,684	$7,441
Incremental cost difference for 20% unbundled compliance	$1,063	$1,073	$1,074	$1,448	$1,764
Incremental cost difference for 20% unbundled (%)	15.82%	15.82%	15.81%	15.86%	19.16%
Revenue Requirement ($000s)	$1,236,413	$1,245,552	$1,247,703	$1,244,920	$1,240,037
Percentage of Revenue Requirement (w/o unbundled)	0.54%	0.54%	0.54%	0.73%	0.74%
Percentage of Revenue Requirement (w/ 20% unbundled)	0.46%	0.46%	0.46%	0.62%	0.60%
Difference	-0.09%	-0.09%	-0.09%	-0.12%	-0.14%

While the 2017-2021 RPIP might suggest that an unbundled REC strategy may be lower than a bundled-only compliance strategy.[7] Consistent with the 2017-2021 RPIP, PacifiCorp continues to monitor the REC market and evaluate the optimal compliance strategy.

Duration of REC Bank

Staff requested that the Company provide additional detail regarding its ability to rely on the REC bank through 2027. PacifiCorp's forecast of the duration of its current REC bank is driven by the 2015 IRP. Although PacifiCorp's 2017-2021 RPIP was updated to reflect the most current information available at the time of the filing, including available eligible resources, the RPIP is limited to a near-term forecast. The 2015 IRP Update, which will be filed March 31, 2016, will provide the most up-to-date analysis from the Company on its anticipated long-term resource use. Changes in the long-term outlook reflected in the 2015 IRP Update and the 2017 IRP may result in changes to the Company's long-term RPS compliance strategy, which will be presented when the Company files its 2019-2023 RPIP.

b. Comments of ICNU

In its comments, ICNU recommends the Company use a flexible capacity resource as its firming resource. In addition, ICNU makes recommendations related to acquisition of new

[7] This assumption is consistent with Commission Order 14-267 in docket UM 1681, which instructed PacifiCorp to include "in subsequent RPIPs a scenario that uses the base case price curve assumptions (medium gas and medium CO2 prices) similar to that used in the other scenarios in the [implementation plan], with the assumption the Company maximizes the use of unbundled RECs for each year analyzed in the [implementation plan] and assuming an unbundled REC price equal to the weighted average price paid for unbundled RECs used for compliance in their last compliance filing."

renewable resources. For the reasons set forth below, PacifiCorp requests the Commission to reject ICNU's recommendations.

Flexible Capacity Resource

ICNU recommends that the Company use a flexible capacity resource as the firming resource in the Company's calculation of incremental cost. Specifically, ICNU recommends the Company use a Wärtsilä or LMS100 Simple Cycle Combustion Turbine (SCCT). ICNU argues that the Frame SCCT currently used by the Company is ill-suited as the firming resource because, as compared to a Wärtsilä or LMS100 SCCT, the Frame SCCT cannot ramp as quickly and is less fuel-efficient.

ICNU's proposal is contrary to the incremental cost methodology agreed to by parties in docket UM 1616, and accepted by the Commission in Order No. 14-034. The stipulation states as follows:

> *To create a capacity-equivalent Proxy CCCT, the fixed costs (including fixed operations and maintenance costs) of a simple-cycle natural-gas fired generating facility ("SCCT") shall be subtracted from the cost of the Proxy CCCT.*[8]

The stipulation also states that this capacity equivalency is intended to capture what some parties referred to as the "firming costs" of the RPS resource relative to the Proxy CCCT. The characteristics of the alternate "firming resources" ICNU proposes might be better characterized as "shaping costs", which were proposed by some parties, but were not an element of the incremental cost methodology agreed upon by parties. The testimony supporting the stipulation indicated that identifiable shaping costs could be included in future incremental cost calculations, but that parties expected them to first be identified in a utility contract, integrated resource plan, rate case, or other filing.[9] The Company believes it is premature to deviate from the stipulated incremental cost methodology at this time in the absence of a demonstration of identifiable costs.

New Renewable Resource Acquisitions

ICNU makes two recommendations related to a possible, and speculative, renewable resource acquisition by the Company. ICNU recommends that any RPS compliance actions that deviate from the RPIP be accompanied by an updated incremental cost calculation that shows the action does not result in PacifiCorp exceeding the four percent cost cap. Second, ICNU recommends that any costs in excess of the four percent cost cap not be borne by customers.

In both cases, ICNU's recommendations are more appropriately addressed in the context of other proceedings. PacifiCorp is focused on delivering RPS compliance on a least-cost, risk-adjusted basis. The issue of whether the Company should pursue an early-action acquisition of an RPS-eligible resource is one that will be addressed as part of the Company's IRP process.

---

[8] UM1616 Stipulation, pg. 4.
[9] UM 1616 Joint Stipulating Parties / 100 / pg. 15.

Similarly, disallowance of costs in excess of the incremental cost cap is most appropriately addressed in the context of a future cost recovery proceeding where the prudence of the investment decision can be fully analyzed—cost recovery should not hinge solely on whether the investment results in incremental costs in excess of the four percent cap.

c. <u>Comments of SBUA</u>

SBUA's comments focus on the need for additional information regarding renewable energy programs offered by the Company and the correlation between the RPS and rates. The remainder of SBUA's comments do not appear to raise concerns or issues specific to the 2017-2021 RPIP.

SBUA requests information regarding the level of Blue Sky sales and "other renewable energy purchase programs" made to small commercial customers and at what retail rates. Blue Sky and other voluntary renewable programs are not part of the RPS framework, and therefore, the Company highlights the fact that this is not the proper forum for a discussion of these issues.

SBUA also requests information regarding correlations between the RPS and rate spread, according to changes in load. The request appears to be related to information presented in the IRP that showed increases in wholesale electricity prices. Rate spread is determined in general rate cases, and thus analysis of rate spread is not contained in the 2017-2021 RPIP. As overall rates increase, the fixed cost resources for RPS compliance may provide greater value, and the cost of RPS compliance may be lower.

III. Conclusion

PacifiCorp appreciates the opportunity to provide these comments.

Respectfully submitted this 18th day of March, 2016.

Etta Lockey
Senior Counsel
PacifiCorp
825 NE Multnomah Street, Suite 1800
Portland, OR 97232-2135
Phone: (503) 813-5701
etta.lockey@pacificorp.com