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September 16, 2015

VIA ELECTRONIC FILING

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

Attn: Filing Center

Re: Docket UM 1662—Joint Prehearing Brief of Portland General Electric and PacifiCorp

PacifiCorp d/b/a Pacific Power (PacifiCorp) submits for filing the Joint Prehearing Brief of Portland General Electric Company and PacifiCorp.

Please direct any informal inquiries to Jay Tinker at (503) 464-7002 or Erin Apperson at (503) 813-6642.

Sincerely,

R Bryce Dalley / ea

R. Bryce Dalley
Vice President, Regulation

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1662

In the Matter of PORTLAND GENERAL ELECTRIC COMPANY and PACIFICORP d/b/a PACIFIC POWER, Request for a Generic Power Cost Adjustment Mechanism Investigation	**JOINT PREHEARING BRIEF OF PORTLAND GENERAL ELECTRIC AND PACIFIC POWER**

JOINT PREHEARING BRIEF OF

PORTLAND GENERAL ELECTRIC AND PACIFIC POWER

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TABLE OF CONTENTS

TABLE OF AUTHORITIES

Washington Utilities and Transportation Commission Orders

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

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In the Matter of PORTLAND GENERAL ELECTRIC COMPANY and PACIFICORP d/b/a PACIFIC POWER, Request for a Generic Power Cost Adjustment Mechanism Investigation	**JOINT PREHEARING BRIEF OF PORTLAND GENERAL ELECTRIC AND PACIFIC POWER**

I. INTRODUCTION

Portland General Electric Company (PGE) and PacifiCorp d/b/a Pacific Power (Pacific Power), collectively referred to as the Joint Utilities, respectfully submit this Joint Prehearing Brief to the Public Utility Commission of Oregon (Commission). The Oregon Renewable Portfolio Standard (RPS), enacted by the Oregon Legislature in 2007 in Senate Bill (SB) 838 and codified in ORS Chapter 469A, requires the Joint Utilities to deliver an increasing percentage of their electricity from renewable energy resources. In SB 838's preamble, the Legislature stated that it is "necessary for Oregon's electric utilities to decrease their reliance on fossil fuels for electricity generation and to increase their use of renewable energy sources."[1] To facilitate this transition, the Legislature authorized the Joint Utilities to recover in rates all prudently incurred costs of compliance with the RPS.[2]

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[1] The Staff of the Commission (Staff) cited this aspect of the preamble of SB 838 as evidence of the intent of SB 838 in *In the Matter of Portland Gen. Elec. Co. 2011 RPS Compliance Report*, Docket No. UM 1605, Order No. 12-436, App. A at 3 (Nov. 15, 2012) and *In the Matter of PacifiCorp, dba Pac. Power 2011 RPS. Compliance Report*, Docket No. UM 1606, Order No. 12-435, App. A at 5 (Nov. 15, 2012). The Commission's final orders in these dockets adopted Staff's reports.

[2] ORS 469A.120.

Eight years later, the Joint Utilities have made significant progress in transitioning their fuel mix from fossil fuels to renewable energy. But the reciprocal promise of ORS 469A.120(1)—that utilities would recover the costs of this paradigm shift—remains partially unfulfilled because the Joint Utilities have persistently under-recovered their variable costs of RPS compliance. In response, the Joint Utilities have proposed a new regulatory approach, the renewable resources tracking mechanism (RRTM), to fully capture the variable costs and benefits of RPS compliance in rates.

The Joint Utilities' request presents important legal and policy questions for consideration by the Commission, including the proper legal interpretation of ORS 469A.120(1), how the Commission can continue to support the goals of the RPS, and whether the design of the RRTM is fair and reasonable. These issues will take on increasing importance as the Joint Utilities' RPS compliance obligations move to 25 percent in 2025.

In this prehearing brief, the Joint Utilities explain the need for the RRTM, outline how the RRTM is consistent with the cost recovery provisions in SB 838, and describe how implementation of the RRTM will allow the Joint Utilities to better track and recover (or return) their prudently incurred variable costs (or variable benefits) associated with compliance with the RPS. The Joint Utilities also address the concerns raised in the testimony of Staff, the Citizens' Utility Board of Oregon (CUB), and Industrial Customers of Northwest Utilities (ICNU), and respond to Staff's alternative proposal to modify the RRTM. Finally, the Joint Utilities offer a suggestion for Commission evaluation of the RRTM after a three-year implementation period to allow an opportunity for changes or improvements to the RRTM based on its initial operation.

II. BACKGROUND

On June 19, 2013, the Joint Utilities initiated this proceeding by requesting that the Commission open a generic investigation of the policies and design of the power cost adjustment mechanism (PCAM). Staff, CUB, and ICNU informally indicated that they opposed a broad investigation into the PCAM. As a compromise, by letter dated March 21, 2014, the Joint Utilities narrowed the request for investigation to focus on the ratemaking treatment of variable RPS compliance costs. At the Commission's Public Meeting on November 12, 2014, Staff acknowledged the possibility that the Joint Utilities were not recovering the variable costs of RPS compliance, and recommended that the Commission open a limited investigation into the treatment of variable costs of RPS compliance. CUB provided oral comments at the Public Meeting opposing the initiation of an investigation, and the Commission adopted Staff's recommendation over CUB's objection.

Administrative Law Judge Patrick Power convened a prehearing conference on December 19, 2014. CUB, ICNU, Renewable Northwest, and Noble Americas Energy Solutions intervened in the proceeding. The Joint Utilities filed opening testimony on March 16, 2015. On April 22, 2015, the parties held a workshop and settlement conference. Staff, CUB, and ICNU filed reply testimony on May 11, 2015. On June 22, 2015, the Joint Utilities filed rebuttal testimony, and Staff and ICNU filed cross-answering testimony. A hearing was initially scheduled for July 17, 2015; however, on July 7, 2015 Judge Power issued a memorandum postponing the hearing. On July 17, 2015, the Commission issued a notice scheduling the hearing for September 28, 2015.

In their opening testimony, the Joint Utilities explained the need for a new approach to recovery (or return) of the variable costs (or variable benefits) associated with RPS compliance, and proposed the RRTM. For utility-owned resources, the RRTM calculates an NPC variance based on the difference between forecasted market value of forecasted output and actual market value of actual output.[3] The NPC variance will include the difference between forecasted and actual royalty payments and integration costs, as applicable.[4] If forecasted and actual output is equivalent for any given hour, the power cost variance will be set to zero.[5] For contracted resources, the RRTM calculates the NPC variance based on the difference between forecasted output and margin and actual output and margin, with margin determined as the difference between the market price and contract price.[6]

In addition to variances in NPC, the RRTM would track variances in related production tax credits (PTCs) for RPS compliant resources.[7] To determine the amount of PTC variances, the RRTM calculates the difference between forecast PTCs based on the utility's most recent general rate case and actual PTCs generated.[8] To determine the value of the PTC variance, the RRTM applies the $/MWh rate used in the most recent general rate case for forecasted PTCs, and values the actual PTCs at the $/MWh rate as established by the Internal Revenue Service for the year in question.[9]

The RRTM operates by tracking on an annual basis generation and market price variances associated with renewable resources, and related PTC variances. The Joint Utilities will individually establish an NPC forecast for year one, and actual costs will be tracked for year one.[10] In year two, the Joint Utilities will calculate the variances between

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[3] PGE-PAC/100, Tinker-Dickman/10.
[4] *Id.*
[5] *Id.*
[6] *Id.*
[7] *Id.* at 8.
[8] *Id.* at 12.
[9] *Id.*
[10] *Id.* at 9.

forecasted and actual costs, and remove the variable costs associated with renewable resources from their respective PCAMs.[11] The Joint Utilities will individually file to include any variance in rates effective January 1 of year three, and the process will repeat annually.[12] Additionally, if the Commission has concerns over potential unintended consequences of the RRTM, there are tools the Commission can employ (such as ordering a review of the RRTM after its first three years of operation), which can alleviate these concerns. This review would allow any necessary refinements to be made to the RRTM based on the Joint Utilities' and stakeholders' actual experience with the RRTM.

Staff, CUB, and ICNU recommend the Commission reject the RRTM in its entirety.[13] Staff, CUB, and ICNU claim that the:

- RRTM is unnecessary because existing cost recovery mechanisms are adequate;
- The cost recovery provisions of the RPS do not mandate "dollar-for-dollar" recovery of RPS-related costs;
- The RRTM is not properly designed; and
- The Commission has previously considered and rejected similar proposals.

Staff proposes that, if the Commission decides to adopt the RRTM, the design should be modified to remove market price risk, to account for load forecast error, to apply an earnings test, and that any recovery should be through a new tariff rather than through the Renewable Adjustment Clause (RAC). As explained further below, the Commission should reject these arguments and adopt the RRTM as proposed by the Joint Utilities in their opening and rebuttal testimony, with a suggested Commission review of the RRTM following a three-year implementation period.

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[11] *Id.* at 10.
[12] *Id.*
[13] Staff/200, Crider/5; CUB/100, Jenks-Hanhan/16; ICNU/100, Mullins/1.

III. ARGUMENT

A. The RRTM is Necessary.

Staff, CUB, and ICNU claim that the RRTM is not necessary because "the existing power cost recovery mechanism is the proper method for recovery of RPS-related costs."[14] Currently, the Joint Utilities forecast RPS variable costs in their annual power cost filings, PGE's Annual Update Tariff (AUT) and Pacific Power's Transition Adjustment Mechanism (TAM). The Joint Utilities recover variances between forecast and actual RPS variable costs and benefits through their respective PCAMs. PGE's PCAM was developed in 2007, before enactment of the RPS, and Pacific Power's PCAM was modeled on PGE's PCAM.[15]

The Joint Utilities' PCAMs include deadbands, sharing bands, and earnings tests, and are designed to be "limited to unusual events and capture the power cost variances that exceed those considered normal business risk for the utility."[16] Because the PCAMs are limited to exceptional power cost variances, they do not fully capture the normal variances between forecast and actual RPS compliance costs and benefits. Essentially, Staff, CUB, and ICNU argue that variances for variable RPS costs within the range of "normal business risk" are to be absorbed by the utility, despite the fact that the Joint Utilities are authorized by statute to fully recover these costs and the Commission's "normal business risk" standard predates this statute.

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[14] Staff/200, Crider/5; CUB/100, Jenks-Hanhan/7 ("just because a cost changes, and rates are not changed to reflect the new cost, it does not mean that a utility is not fully recovering that particular cost"); ICNU/100, Mullins/2 ("I don't agree with the Joint Utilities' argument that their current PCAMs do not allow them to recover the variable costs of renewable resources").

[15] *In the Matter of Portland Gen. Elec. Co.*, Docket Nos. UE 180, UE 181, UE 184, Order No. 07-015 at 26-27 (Jan. 12, 2007); *In the Matter of PacifiCorp, dba Pac. Power, Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 14 (Dec. 20, 2012).

[16] Order No. 12-493 at 14.

The Joint Utilities have experienced large variances between the forecast and actual costs of RPS compliance over the last eight years. For the years 2007 through 2013, the forecasted net market value of Pacific Power's wind generation reflected in the TAM has exceeded actuals by an average of $31.6 million per year.[17] PGE has experienced similar difficulty forecasting its variable RPS costs in base rates, with forecasted renewable generation deviating from actuals by up to $24 million in a given year.[18] As explained in the testimony of the Joint Utilities, the energy from renewable generation is included in the Joint Utilities' annual power cost modeling as an offset to NPC, with a credit (or "negative cost") based on the utility's avoided cost of fuel, market purchases, or market sales.[19] To the extent that the actual generation or actual market prices differ from the forecasts, the negative cost of the renewable generation may be overstated or understated in rates.[20] The Joint Utilities ultimately absorb these cost variances, which are generally not recoverable under their PCAMs.

In addition, variances in PTCs are particularly critical to track in the RRTM because changes in PTC values are not captured in the Joint Utilities' annual power cost updates or PCAMs. Without the RRTM, there is no ability for the Joint Utilities to capture changes in PTC costs or benefits absent filing a rate case. While the Joint Utilities have proposed the RRTM as an integrated mechanism to track both NPC variances and PTC variances, the two components of the mechanism are severable. In other words, the Commission could adopt an RRTM that tracks only one of these variances and not the other.

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[17] PAC-PGE/100, Tinker-Dickman/6-7.
[18] *Id.* at 7.
[19] PGE–PAC/200, Tinker–Dickman/5.
[20] *Id.*

B. The RPS Supports Adoption of the RRTM.

The RPS allows the Joint Utilities to recover in rates "*all* prudently incurred costs associated with compliance" with the RPS.[21] The RRTM addresses the current recovery gap for RPS compliance costs under the PCAMs in a targeted and straightforward manner. Staff, CUB, and ICNU claim that the RRTM is inconsistent with SB 838, because SB 838 does not mandate "dollar-for-dollar" recovery of RPS compliance costs.[22] This position is not supported by the plain language, legislative history, or policy goals of SB 838.

To ascertain the meaning of a statute, an Oregon court will perform a three-step analysis. First, the court will look to the text and context of the statute.[23] The court will next consider the legislative history if useful to the court's analysis.[24] If the legislature's intent remains unclear, the court may apply general maxims of statutory construction to resolve remaining uncertainty.[25]

The cost recovery provisions of SB 838 support the RRTM based on the plain language of the statute alone. As set forth below, the legislative history of SB 838 also supports the RRTM, and the RRTM promotes the policy goals of the RPS.

1. The Plain Language of SB 838 Supports the RRTM.

When examining a statute's text and context, a court will give words of common usage "their plain, natural, and ordinary meaning."[26] ORS 469A.120(1) provides that:

> [A]ll prudently incurred costs associated with compliance with a renewable portfolio standard are recoverable in the rates of an electric

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[21] ORS 469A.120(1) (emphasis added).
[22] Staff/200, Crider/5; CUB/100, Jenks-Hanhan/4; ICNU/100, Mullins/4.
[23] *State v. Gaines*, 346 Or 160, 171 (2009).
[24] *Id.* at 171-172.
[25] *Id.* at 172.
[26] *In the Matter of PacifiCorp, dba Pac. Power, Petition for a Declaratory Ruling Regarding ORS 757.480*, Docket No. DR 47, Order No. 14-254 at 4 (July 8, 2014) (*citing Portland Gen. Elec. Co. v. Bureau of Labor & Indus.*, 317 Or 606, 859 (1993)).

> company, including interconnection costs, costs associated with using physical or financial assets to integrate, firm or shape renewable energy sources on a firm annual basis to meet retail electricity needs, above-market costs and other costs associated with transmission and delivery of qualifying electricity to retail electricity consumers.

The statute includes a broad and detailed description of the types of compliance costs recoverable under the statute, which includes the variable costs of delivering renewable power to customers. The plain language of the statute differentiates RPS compliance costs from other utility costs to assure 100 percent recovery. There would be no reason for this detailed categorization of costs if, as other parties argue, the legislature intended these costs to be lumped with all other costs in the general rate making process—irrespective of the efficacy of that process to provide full recovery. A statute must be construed to give effect to the meaning of all of its language if possible.[27] Therefore, the Commission should interpret ORS 469A.120(1) as providing certainty of recovery of RPS compliance costs on a single-item cost basis, irrespective of the treatment of the utility's other costs.

SB 838 specified a mechanism for recovery of capital costs, an automatic adjustment clause, which the Commission implemented through the creation of the RAC.[28] SB 838 *did not* specify a particular recovery mechanism for other prudently incurred RPS compliance costs, including variable costs. Instead, SB 838 specified the result required—100 percent cost recovery—but allowed the Commission discretion in how to accomplish this mandate.

CUB argues that the legislature intended for the costs to construct or otherwise acquire RPS resources to be recovered through the RAC, and that all other prudently incurred costs associated with RPS compliance must be recovered through existing ratemaking

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[27] ORS 174.010 provides that "where there are several provisions or particulars such construction is, if possible, to be adopted as will give effect to all." *See also Pac. Coast Recovery Serv. v. Johnston,* 219 Or App 570, 576–577 (2008) (refusing to adopt interpretation that would render statutory provision a nullity).

[28] ORS 469A.120(2).

mechanisms only.[29] There is no language in the statute that supports CUB's position. When interpreting the text and context of a statute, a fundamental maxim is "not to insert what has been omitted, or to omit what has been inserted."[30] Because CUB asks the Commission to read into the statute a limitation that the legislature did not include, the Commission should reject CUB's proposed interpretation of SB 838.

2. The Legislative History Supports the Joint Utilities' Interpretation of ORS 469A.120(1).

The legislative history of SB 838 does not, as CUB claims, show that the Legislature decided to limit variable cost recovery to "currently existing automatic adjustment clauses or through a general rate case."[31] CUB's support for this statement is an undated memorandum authored by CUB, which is not a part of the record of SB 838 testimony and exhibits maintained by the Oregon Secretary of State. Without evidence that the Legislature was aware of and considered CUB's memorandum, the memorandum does not constitute legislative history of SB 838.[32]

The legislative record maintained by the Oregon Secretary of State shows that at the time of enactment of SB 838, stakeholders were focused on the mechanism for recovery of capital investments and did not specifically propose cost recovery mechanisms for the variable costs of RPS compliance. Consistent with the delegation of this issue to the

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[29] CUB/100, Jenks-Hanhan/6.
[30] ORS 174.010.
[31] CUB/100, Jenks-Hanhan/6.
[32] Legislative history evidence by a nonlegislator witness is relevant only to the extent it can be demonstrated that legislators relied upon that evidence and there is no contradictory evidence in the record. *See State v. Kelly*, 229 Or App 461, 471 (2009) ("when . . . a [nonlegislator] witness represents the original sponsor of legislation and when it is clear that legislators relied on the witness's statements, those statements are regarded as reliable indicators of legislative intent"); *Fast v. Moore*, 205 Or App 630, 638 (2006) (for nonlegislator witness that "represented the organization that drafted the bill and because his explanation of the bill's purpose and effect was uncontradicted, it is reasonable to assume that the legislators who heard and read his testimony relied on it and adopted his understanding of the bill.").

Commission under ORS 469A.120(1), the testimony in support of SB 838 includes only high-level statements that as renewable generation comes on line, variable costs go down,[33] and utility-owned resources generate "free energy."[34] The testimony did not drill down on the costs to the utility of incorrectly forecasting the energy credit from renewable resources, which are the focus of the RRTM. The dearth of testimony on these costs does not mean that the Legislature intended to exclude these costs from ORS 469A.120(1). Rather, it shows that these costs were not well understood eight years ago, and demonstrates recognition that the Commission would resolve the design and scope of the variable cost recovery mechanism, not the Legislature.

3. The RRTM Supports the Policy Goals of the RPS.

The RPS was established to facilitate a transition for Oregon's electric utilities from fossil fuels to increased use of renewable energy, incrementally working toward a goal of providing 25 percent of electric service with renewable energy by 2025. To achieve this end, the Legislature authorized utilities to recover their prudently incurred costs of RPS compliance, and specifically enumerated the types of costs that may be recovered.[35] Thus, the policy of the RPS is clear: utilities should increase the use of renewable energy and utility customers should pay for those costs.

Under the existing regulatory framework, the Joint Utilities recover variances in net power costs, including variable RPS compliance costs, through their respective PCAMs. The

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[33] For example, CUB stated: "as a renewable resource comes on line, the utility's variable costs, or costs of fuel, go down and those savings will be passed on to the customer through annual rate adjustment that are currently in place." Senate Environmental and Natural Resources Committee, SB 838, Mar. 15, 2007, Exhibit P at 1 (written testimony of Jason Eisdorfer, CUB).
[34] In oral testimony, a Pacific Power representative testified that: "[W]hen we own the renewable [resource], the renewable kilowatt hours have a zero variable cost. As a result, customers in Oregon receive free energy, essentially, through the adjustment mechanism." House Committee on Energy and Environment, SB 838, Apr. 18, 2007, audio recording at approximately 1 hour, 24 minutes (oral testimony of Brent Gale, PacifiCorp).
[35] ORS 469A.120(1).

PCAMs are designed to require the utility to absorb variances associated with "normal business risk" and include an asymmetric deadband, with a positive annual power cost variance deadband of $30 million and a negative annual power cost variance deadband of $15 million. Under this framework, the utility bears 100 percent of the risk for non-recovery of RPS compliance cost variances in the deadband.

As a general matter, this regulatory framework provides more favorable cost recovery of flexible fossil fuel resources than less predictable renewable resources. This is contrary to the policy of the RPS to encourage the Joint Utilities' transition away from fossil fuels. The RRTM makes the transition to more volatile renewable resources cost neutral for the Joint Utilities—as intended by the RPS.

C. The RRTM is Designed to Accurately Capture the Variable Costs of RPS Compliance.

The RRTM presents the most appropriate tool for isolating, calculating, and recovering the variable costs of RPS compliance. The RRTM calculates variable RPS compliance costs by comparing forecasted market value of forecasted output and actual market value of actual output, for owned resources.[36] For contracted resources, the RRTM calculates the NPC variance based on the difference between forecasted output and margin and actual output and margin, with margin determined as the difference between the market price and contract price.[37] The actual market value is based on a published market index, PowerDex.[38] While Staff, CUB, and ICNU take issue with several components of the RRTM design, as described below, none of these concerns warrant rejection of the RRTM.

[36] PGE-PAC/100, Tinker-Dickman/10.
[37] *Id.*
[38] PGE-PAC/200, Tinker-Dickman/12.

1. PCAM Design Principles are Irrelevant to the RRTM.

ICNU argues that the RRTM is improper because it does not comply with the Commission's guidelines for a properly designed PCAM.[39] The RRTM is tailored to track and allow 100 percent recovery for only those costs designated in ORS 469A.120(1). This statute renders the PCAM design principles inapplicable to RPS variable compliance costs.

2. It is Appropriate to Include PTCs in the RRTM.

ICNU argues that including PTCs in the RRTM may harm customers by producing an inaccurate level of Accumulated Deferred Income Tax (ADIT), because PTCs not claimed in a given year can reduce ADIT.[40] While ICNU is technically correct, the overall impact on revenue requirement is minor. ADIT is reflected on a balance sheet, whereas PTCs are reflected on the income statement, and for revenue requirement purposes there is an approximately 90/10 relationship between the PTCs and ADIT. Because of this relationship, the inclusion of PTCs in the RRTM has a negligible impact on overall levels of ADIT.[41] The Joint Utilities' power cost updates and PCAMs do not provide a mechanism for recovery or refund of PTC variances. Including PTCs in the RRTM is essential because PTCs are a readily quantifiable, direct benefit of RPS compliant resources. In addition, PTCs have always been reflected in the Joint Utilities' renewable adjustment clauses.[42] If actual PTCs are less than forecasted, the Joint Utilities would incur an additional cost, and if PTCs are greater than forecast, the resulting RPS compliance benefits would be returned to customers.

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[39] ICNU/100, Mullins/7.
[40] *Id.* at 17-18.
[41] PGE-PAC/200, Tinker-Dickman/16.
[42] *See, e.g.*, *In the Matter of PacifiCorp, dba Pac. Power 2009 Renewable Adjustment Clause Schedule 202*, Docket No. UE 200, Order No. 08-548 at 4 (Nov. 14, 2008) ("The benefits of the federal production tax credits are accounted for in this RAC proceeding."); *In the Matter of Portland Gen. Elec. Co., Application for Deferred Accounting of Qualifying Renewable Resource Projects*, Docket No. UM 1471, Order No. 10-116 (Apr. 1, 2010).

3. Using Actual Market Prices from an Independent Market Index is Appropriate to Determine the Variance between Forecast Market Prices and Actual Market Prices.

Staff, CUB, and ICNU allege that including market prices in the RRTM adds market price risk to the determination of variable RPS compliance costs. Staff criticizes the comparison of forecast market prices to actual market prices, and instead recommends using only forecast market prices, eliminating any comparison between forecast and actual prices,[43] or using a comparison of forecast market prices and actual transaction costs.[44] First, the use of only forecast market prices to value renewable generation removes the market price variability from the RRTM, and fails to account for a significant component of the variable costs of RPS compliance. The Joint Utilities currently bear the risk of market price variability, and believe it is appropriate for the market price risk to be reflected as part of the actual cost to customers of RPS compliance. Second, while it is possible to use actual transaction prices instead of published market prices, as Staff recommends, the use of actual transaction prices would make comparison of forecast and actual market prices significantly more cumbersome without improving the operation of the RRTM.

CUB argues that the Joint Utilities may not rely solely on the spot market to adjust for forecast errors, and accordingly, market prices may be disconnected from the utility's resource action and actual NPC.[45] As mentioned above, the Joint Utilities could use actual transaction costs in lieu of using a published index, however, it would add substantial complexity to the RRTM without adding commensurate benefit.

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[43] Staff/100, Crider/19; Staff/200, Crider/6.
[44] Staff/100, Crider/17; Staff/200, Crider/6.
[45] CUB/100, Jenks-Hanhan/14-15.

ICNU is concerned that including market prices in the RRTM may result in a variance even if the forecast for generation output is perfectly accurate.[46] The design of the RRTM addresses this point by setting the power cost variance to zero for any hour in which forecasted and actual output is equivalent.[47]

ICNU also suggests that including market prices in the RRTM may cause the RRTM to have an inverse relationship with NPC, potentially affording the Joint Utilities additional recovery through the RRTM when none is warranted.[48] ICNU is wrong. Including market price in the RRTM does not cause the RRTM to have an inverse relationship with NPC, because NPC does not always move in the same direction as market prices, in some cases (for example, greater than anticipated generation), lower market prices may still operate to create a refund to customers.[49]

In sum, the variable costs of RPS compliance cannot be determined without proper consideration of the value of the energy generated by the RPS resources, and the use of a published market index appropriately reflects the market price variability for purposes of determining actual RPS compliance costs.

4. PowerDex is the Appropriate Tool for Determining Market Price.

CUB criticizes the Joint Utilities' use of PowerDex because the information in PowerDex is beyond the scope of normal protective order.[50] To resolve this concern, the

[46] ICNU/100, Mullins/12.
[47] PGE-PAC/100, Tinker-Dickman/10.
[48] ICNU/100, Mullins/13.
[49] PGE-PAC/200, Tinker-Dickman/12-13.
[50] CUB/100, Jenks-Hanhan/16.

Joint Utilities have acquired permission from PowerDex to provide the hourly prices to parties as highly confidential information.[51]

5. RPS Variable Costs are Independent from the Load Forecast.

Staff recommends including a modification to RRTM design to account for variance in load forecast.[52] It is inappropriate to include an adjustment for load variance, as the NPC variance related to RPS resources occurs whether or not the load forecast is accurate.[53] Because RPS resources are not dispatchable, load and RPS generation are independent of each other and there is no basis for accounting for load forecast variance in the RRTM.[54]

6. An Earnings Test is Unnecessary and Inappropriate.

Staff, CUB, and ICNU express concern that, without an earnings test, the Joint Utilities may recover RPS compliance costs in excess of actual NPC and introducing the possibility of over-earning.[55] ICNU expressed concern that the Joint Utilities may receive a windfall.[56] CUB indicated that it was concerned that, for PGE, double counting may occur as a result of adjustment to PGE's AUT for wind day-ahead forecast error.[57]

Removing forecast and actual costs of renewable resources from the PCAM will prevent double-counting. In addition, the Joint Utilities agreed to cap the RRTM at the actual NPC to preclude recovery or refund of costs above or below actual NPC.[58] Notably, in

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[51] PGE-PAC/200, Tinker-Dickman/12.
[52] Staff/100, Crider/10; Staff/200, Crider/6.
[53] PGE-PAC/200, Tinker-Dickman/17.
[54] *Id.*
[55] Staff/100, Crider/16; CUB/100, Jenks-Hanhan/7; ICNU/100, Mullins/8.
[56] ICNU/100, Mullins/8.
[57] CUB/100, Jenks-Hanhan/11-12.
[58] PGE-PAC/100, Tinker-Dickman/12; PGE-PAC/200, Tinker-Dickman/11-12.

another example of a cost recovery mechanism required by the RPS—the RAC—the Commission did not require an earnings review.[59]

7. The Challenges in Isolating RPS Compliance Costs Do Not Justify Rejection of the RRTM.

ICNU cites the difficulty associated with isolating RPS compliance costs as reason for rejecting the RRTM, and criticizes the RRTM for not including wind integration costs.[60] The Joint Utilities agree that identifying and isolating all variable RPS compliance costs presents complexities, but this does not justify disregard of ORS 469A.120(1). The RRTM is a straightforward mechanism designed to capture the chief components of RPS variable costs variances: generation output and market prices. In addition, the Joint Utilities' suggestion for Commission and stakeholder review of the RRTM following a three-year implementation period will allow for refinements to the RRTM as necessary.

8. The RRTM Will Not Undermine the Diversity Benefits of the Joint Utilities' Resource Portfolios.

ICNU expresses concern that the RRTM, by isolating one component of utility resource portfolios, will not capture the diversity benefits of entire utility resource portfolio.[61] ICNU's fear is misplaced. The TAM and the AUT will still include the benefits of the Joint Utilities' non-renewable resources. Additionally, while the Joint Utilities adhere to principles of least-cost and least-risk in developing their anticipated resource needs, the RPS adds a new dimension to the Joint Utilities' resource portfolios which must be recognized.[62]

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[59] *In the Matter of Pub. Util. Comm'n of Or. Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket No. UM 1330, Order No. 07-572 at 4 (Dec. 19, 2007) (order approving stipulation in which parties agreed that earnings review would not apply to the RAC).
[60] ICNU/100, Mullins/8-10.
[61] *Id.* at 10-11.
[62] PGE-PAC/200, Tinker-Dickman/16.

9. Renewable Resource Variability Has No Bearing on the Recoverability of RPS Compliance Costs.

ICNU asserts that the RRTM is not necessary because renewable resource generation does not vary significantly from year to year.[63] The Joint Utilities have demonstrated, however, that the value of the renewable energy credit in rates does vary significantly from year to year, contributing to large, non-recoverable NPC variances under the Joint Utilities' PCAMs. Under ORS 469A.120(1), the Joint Utilities should not be required to continue to bear these cost variances.

10. The Commission Has Not Previously Considered a Proposal Like the RRTM.

CUB and ICNU erroneously claim that the Commission has already considered and rejected proposals similar to the RRTM in dockets UE 246, UE 283, and UE 165.[64] Each of these cases is distinguishable from the current proposal, and none of these cases predetermines the outcome in this case.

In docket UE 246, the Commission explicitly "acknowledge[d] that ORS 469A.120(1) provides for recovery of prudently incurred SB 838 compliance costs"[65] but found that a full PCAM was not the appropriate method to recover variable RPS compliance costs. In docket UE 283, PGE proposed a mechanism similar to the RRTM to allow for the

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[63] ICNU/100, Mullins/13-14.

[64] CUB/100, Jenks-Hanhan/8-10; ICNU/100, Mullins/4-6. ICNU also claims the Washington Utilities and Transportation Commission (WUTC) recently rejected a similar mechanism for Pacific Power in Docket UE-140762. ICNU/100, Mullins/6. In fact, in that case WUTC declined to adopt a narrowly tailored renewable tracking mechanism in favor of a PCAM applicable to all power costs. While the WUTC did not agree with the design of the tracking mechanism, it noted "important to our decision to reject the RRTM, however, is [WUTC] Staff's interest in effecting a broader solution to address the Company's challenges in terms of power cost recovery." *Wash. Utils. & Transp. Comm'n v. Pac. Power*, Docket UE-140762, Order No. 08 ¶108 (Mar. 25, 2015). Pacific Power did not previously have a PCAM in place in Washington, and it is not clear whether the WUTC would have viewed the RRTM differently if it would have been proposed as a complement to an existing PCAM rather than as a standalone proposal.

[65] Order No. 12-493 at 14.

recovery of variable RPS compliance costs, but PGE ultimately withdrew the proposal as part of a settlement agreement before the Commission had an opportunity to evaluate it. CUB and ICNU also cite docket UE 165, a case in which the Commission rejected PGE's proposed hydro-only PCAM; however, this case predates the adoption of the Joint Utilities' respective PCAMs and the enactment of SB 838, and is irrelevant to the issues raised in this case.

In the Staff Report recommending initiation of this investigation, Staff explains:

> The Companies' request for an investigation presents a policy question regarding recovery of RPS-related costs that the Commission has not yet considered. . . . [T]he Commission has not yet specifically considered whether it is appropriate, or practical, to isolate the RPS-related costs from other net variable power costs for ratemaking treatment.[66]

Despite stakeholder opposition to the proposal for separate treatment of RPS compliance costs, Staff agreed that "the policy issue is sufficiently important, and the dollars at stake sufficiently material, to warrant the Commission's examination."[67] The policy questions presented here are matters of first impression for the Commission.

D. The Commission Should Adopt the RRTM as Proposed and Reject Staff's Proposed Alternative.

If the Commission adopts an RRTM, Staff proposes several modifications intended to eliminate what Staff perceives as risk elements: (1) removing market risk by using forecast market price to determine energy costs; (2) removing forecast risk by netting changes in RPS generation against changes in load; (3) using actual transaction costs instead of PowerDex index pricing to determine market prices; (4) including an earnings test identical to the

[66] Staff Report at 5 (Nov. 12, 2014).
[67] *Id.*

PCAM earnings test; and (5) requiring recovery under a new tariff rather than the RAC.[68] Staff's proposed modifications are unnecessary and should be rejected, except for the proposal to make the RRTM filing as a separate tariff filing.[69]

Staff's proposed alternatives limit the RRTM calculation to changes in RPS generation volume, without consideration of the cost impact that flows through actual NPC. The result of the modifications is to distort the value of the RPS benefit embedded in NPC, which may cause inaccurate and illogical deferrals or refunds. By removing actual market prices from the determination of variable power costs, Staff eliminates the source of a significant component of variable RPS compliance costs. Additionally, Staff's proposal is silent regarding PPAs. The Joint Utilities believe that the RRTM method should also include PPA variances.

As noted above, it is unnecessary to account for load variance because renewable resources are non-dispatchable, and it is unnecessary to use actual transaction costs, as it will not improve the operation of the RRTM. An earnings test identical to that in the PCAM is unwarranted and not consistent with the legislative mandate allowing for recovery of all prudently incurred costs of RPS compliance. As mentioned in their opening testimony, the Joint Utilities are open to submitting the RRTM as a separate tariff.[70]

IV. CONCLUSION

After eight years of experience with the RPS, it is clear that current ratemaking approaches do not permit the Joint Utilities to recover their full variable costs of compliance

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[68] Staff/200, Crider/6.
[69] ICNU opposes Staff's alternative proposal on the basis that it does not address ICNU's concerns with the RRTM. ICNU/200, Mullins/3-5. While the Joint Utilities do not support Staff's proposed alternative, the Joint Utilities disagree with ICNU's criticisms for the reasons addressed above.
[70] PGE-PAC/100, Tinker-Dickman/8.

or to credit full variable benefits to customers. The Joint Utilities proposed the RRTM to comprehensively address the variable costs of compliance with the RPS, and by taking into account *both* generation and market variances, the RRTM is designed to accurately reflect the actual costs of RPS compliance to the Joint Utilities. The RRTM is consistent with the RPS, and the Commission has discretion to implement the RRTM. It is critical that the Commission act now, as the cost recovery challenges will only grow in magnitude as the Joint Utilities prepare to meet the RPS target of 25 percent of load served by renewable resources in 2025.

The Joint Utilities' proposed RRTM provides a straightforward tool to allow recovery of the prudently incurred costs of compliance with the RPS. The RRTM is necessary, consistent with SB 838, and appropriately balances risk. To ensure that the RRTM operates as intended, the Joint Utilities propose that the Commission evaluate the RRTM after three years and consider changes or improvements based on the RRTM's actual results.

In addition, the Commission should consider the importance of the RRTM in tracking the Joint Utilities' PTC variances. Without the RRTM, PTC variances will fall through the gaps of the Joint Utilities' current mechanisms for reflecting the costs of renewable resources in rates.

For these reasons, the Joint Utilities respectfully request that the Commission approve the RRTM as proposed in the direct and rebuttal testimony of the Joint Utilities. Additionally, as a tool to address any potential unintended consequences related to the RRTM, the Joint Utilities suggest the Commission use their discretion to modify the RRTM to allow for review following a three-year implementation period.

Respectfully submitted this 16th day of September, 2015.

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