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October 19, 2015

VIA ELECTRONIC FILING

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

Attn: Filing Center

RE: UM 1662—Joint Opening Brief of Portland General Electric and PacifiCorp

PacifiCorp d/b/a Pacific Power (PacifiCorp) submits for filing the Joint Opening 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/ eak

R. Bryce Dalley
Vice President, Regulation

Enclosure

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 OPENING BRIEF OF

PORTLAND GENERAL ELECTRIC AND PACIFIC POWER

October 19, 2015

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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 Opening Brief to the Public Utility Commission of Oregon (Commission), in accordance with Administrative Law Judge Patrick Power's ruling issued on September 23, 2015. The Joint Utilities propose a new renewable resources tracking mechanism (RRTM) to allow them to separately account for and recover their actual, variable compliance costs consistent with the provisions and policies of Oregon's Renewable Portfolio Standard (RPS).

The Joint Utilities currently recover less than 100 percent of their RPS compliance costs, a fact that Staff, the Citizens' Utility Board of Oregon (CUB), and Industrial Customers of Northwest Utilities (ICNU) all concede in their prehearing briefs.[1] Specifically, as a result of the large dead band under their current power cost adjustment mechanisms (PCAMs), the Joint Utilities each have no opportunity to recover RPS compliance cost variances up to $30 million. And there is no opportunity <u>at all</u> to recover

[1] Staff's Prehearing Brief at 6; CUB's Prehearing Brief at 8; ICNU's Prehearing Brief at 8.

cost variances for changes in production tax credits (PTCs) in PGE's Annual Update Tariff (AUT) and Pacific Power's Transition Adjustment Mechanism (TAM), or in the Joint Utilities' PCAMs or Renewable Adjustment Clauses (RACs).

Staff and the intervenors justify their opposition to the RRTM by interpreting the RPS's cost recovery provision, ORS 469A.120(1), as providing only the basic opportunity for cost recovery that existed pre-RPS. This "status quo" interpretation implies that the legislature's words in ORS 469A.120(1) were meant to add nothing to the RPS, a result that is irreconcilable with normal rules of statutory construction[2] and the carefully crafted provisions of the statute:

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

This interpretation is also contrary to the legislature's intent that: (1) the RPS would do "no harm to the utilities;"[3] and (2) cost recovery would follow the RPS's mandate to invest in specific resources.[4]

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[2] 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).

[3] "[I]n preparation for today, I re-read the bill and I discovered something. What I discovered was that this is a very good bill. It is comprehensive but it is concise. It establishes a clear path to success, but it contains significant flexibilities to achieve that success. It is good for the environment, it is good for consumers, **and it does no harm to the utilities**." House Committee on Energy and Environment, SB 838, Apr. 16, 2007, audio recording at approximately 59 minutes (oral testimony of Jason Eisdorfer, Citizens' Utility Board of Oregon) (emphasis added).

[4] "It actually makes some sense, if you're asking the utilities to make an investment, a specific investment, and they're saying ok, **if we have to make that to meet law, we want to make sure that we have the opportunity to recover those costs if they are prudently incurred.** And I think that makes some sense." House Committee on Energy and Environment, SB 838, Apr. 16, 2007, audio recording at approximately 1 hour, 25 minutes (oral testimony of Lee Beyer, Chair of the Public Utility Commission of Oregon) (emphasis added).

When the Commission interpreted a similar cost recovery provision in Senate Bill (SB) 1149, the Commission expressly recognized and effectuated the dual mandate of the legislature to implement the new program and keep utilities whole by allowing full recovery of actual SB 1149 compliance costs.[5] The Commission has also approved dollar-for-dollar recovery for the solar volumetric incentive rate (VIR) under ORS 757.365(10), which is a more general cost recovery provision than ORS 469A.120(1).

Staff argues that, instead of the RRTM, the Joint Utilities should improve their NPC modeling in the AUT and the TAM. The Joint Utilities have increased their accuracy of forecasting RPS resources and will continue to do so, irrespective of the RRTM. But the inherently unpredictable nature of wind and power markets makes perfect forecasts impossible. Moreover, since the RPS was enacted, the parties to this case have regularly opposed NPC modeling refinements designed to more accurately reflect renewable generation in the AUT and the TAM—in part because of the forecasting challenges involved.[6] The complexity and contentiousness of modeling renewable resources in forecast NPC supports adoption of the RRTM.

To honor the will of the legislature and promote vigorous implementation of the RPS, the Commission should ensure that RPS compliance is cost neutral for utilities. The Joint

[5] *In the Matter of the Application of Portland Gen. Elec. Co. for Authorization to Defer Costs Related to Implementing Senate Bill 1149 and In the Matter of the Application of PacifiCorp for Authorization to Defer Costs Related to Implementing Senate Bill 1149*, Docket Nos. UM 954, UM 958, Order No. 00-165 at 4 (Mar. 17, 2000); *reconsideration denied* Order No. 00-308 (June 9, 2000).

[6] *In the Matter of Portland Gen. Elec. Co. Net Variable Power Costs and Annual Power Cost Update*, Docket No. UE 266, Order No. 13-280 at 9 (Aug. 5, 2013) (ICNU opposed refined wind modeling based on historical average generation); *In the Matter of PacifiCorp 2016 Transition Adjustment Mechanism*, Docket No. UE 296, Redacted ICNU Response Brief at 31-33 (Sept. 28, 2015) (opposing wind modeling refinements); *In the Matter of PacifiCorp 2014 Transition Adjustment Mechanism*, Docket No. UE 264, Order No. 13-387 at 2-4 (Oct. 28, 2013) (approving refined wind modeling over objections from Staff, CUB, and ICNU); *In the Matter of PacifiCorp 2012 Transition Adjustment Mechanism*, Docket No. UE 227, Order No. 11-435 at 26-27 (Nov. 4, 2011) (ICNU opposed wind integration cost modeling).

Utilities urge the Commission to effectuate ORS 469A.120(1) through the RRTM, subject to review after an initial three-year trial period. At a minimum, the Joint Utilities urge the Commission to approve the RRTM to track changes in PTCs, which are not otherwise recoverable outside of a general rate case filing.

II. ARGUMENT

A. The RRTM Effectuates the Goals of the RPS.

The RPS is designed to facilitate the transition of electric utilities from fossil fuels to renewable energy resources, in part by allowing utilities to recover in rates "all prudently incurred costs associated with compliance" with the RPS.[7] The parties disagree about whether ORS 469A.120(1) is clear (Joint Utilities, Staff and ICNU) or contains latent ambiguities (CUB). Irrespective of this issue, the parties generally agree that all prudently incurred RPS compliance costs are "recoverable" and that the Commission has discretion to determine the appropriate method for providing this recovery.

1. The Plain Language of ORS 469A.120(1) Requires an Opportunity for Full Recovery of Prudently Incurred RPS Compliance Costs.

Staff and ICNU argue that the plain meaning of ORS 469A.120 is that RPS compliance costs are "recoverable," meaning "capable of recovery."[8] The Joint Utilities agree with this interpretation, but do not agree that all RPS compliance costs are currently "capable of recovery."

First, perfect forecasting of the actual value of renewable generation for each of the 8,760 hours within a year, from a practical standpoint, is impossible. Any forecasting

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[7] *See 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) (*citing* SB 838's preamble 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" as policy of SB 838).

[8] Staff's Prehearing Brief at 3-4; ICNU's Prehearing Brief at 8.

methodology is subject to limitations based on the complex and dynamic nature of real world factors that influence actual results and the availability of pertinent data. The Joint Utilities, under the AUT or TAM, forecast conditions more than one year into the future. The 8,760 hour forecast of RPS resources within the AUT and TAM will never align perfectly with actual 8,760-hour results. Therefore, the Joint Utilities' full RPS compliance costs are not truly "capable of recovery" in the absence of the RRTM or a similar mechanism.

Second, under the existing PCAM—which predates ORS 469A.120(1)—RPS compliance cost variances are not capable of recovery to the extent they are subject to dead bands, sharing bands, and an earnings test. The asymmetric dead band in PCAMs has a positive annual power cost variance dead band of $30 million and a negative annual power cost variance dead band of $15 million. The Commission designed the PCAM so that a utility would absorb variances within the range of what the Commission considered normal business risk. It was also designed to produce revenue neutrality, meaning that PCAM cost recovery should be fully offset by PCAM rate credits.[9] This central principle of "no net cost recovery" is squarely at odds with ensuring full recovery of variable RPS compliance costs under ORS 469A.120(1).

Third, there is no vehicle for capturing variances in PTCs absent filing a rate case. It is particularly important to track variances in PTCs through the RRTM, because the PTCs are time-limited to ten years. If a utility does not file a rate case for several years, there may be a very limited opportunity to reflect changes in these readily quantifiable RPS-related expenses in rates.

[9] *In the Matter of Portland Gen. Elec. Co.*, Docket Nos. UE 180, UE 181, UE 184, Order No. 07-015 at 26 (Jan. 12, 2007).

The parties argue that ORS 469A.120(1) does not provide an incremental mandate for utility cost recovery. As support, Staff cites the Commission's order in Pacific Power's 2009 RAC filing, which states that "[p]rudently incurred costs always have been recoverable in rates," and "the 'new' feature of SB 838 . . . is its endorsement of the automatic adjustment clause . . . as the vehicle for a utility to recover its prudently incurred costs, pending its next general rate case."[10] In that case, however, the Commission was not addressing recovery of variable RPS compliance costs under ORS 469A.120(1). Instead, the Commission held that SB 838 had not created new law or changed the prudence standard applicable to new renewable resources under ORS 469A.120(2).[11]

The Commission has previously considered similar statutory cost recovery language for SB 1149 implementation costs and for the solar VIR program.[12] Regarding SB 1149, the Commission determined that "SB 1149 provides independent authority for the deferral of costs related to implementation of the Act."[13] The language at issue "provide[d] the electric company an opportunity to recover all costs prudently incurred," and ICNU argued that recovery under SB 1149 should be subject to annual reauthorization and an earnings review under ORS 757.259.[14] The Commission rejected ICNU's assertion regarding the applicability of ORS 757.259, finding that:

> [T]he application of existing statutory law, which without specific legislative reference to its applicability, undermines the overall intent of the legislation to insure that that all costs, prudently expended by

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[10] Staff's Prehearing Brief at 3 (*citing In the Matter of PacifiCorp, dba Pac. Power 2009 Renewable Adjustment Clause Schedule 202*, Docket No. UE 200, Order No. 08-548 at 18 (Nov. 14, 2008)).
[11] This reading of Order No. 08-548 is consistent with CUB's and ICNU's position that the legislature intended for the automatic adjustment clause to provide dollar-for-dollar recovery of non-variable RPS compliance costs. CUB's Prehearing Brief at 7; ICNU's Prehearing Brief at 7.
[12] ORS 757.365.
[13] Order No. 00-165 at 3.
[14] *Id.* at 2 (*citing* SB 1149, Section 18(4)(a)).

> electric companies to comply with the provisions of the Act, are recoverable.[15]

The Commission found that application of ORS 757.259 to recovery of SB 1149 implementation costs would create an unintended practical impediment to the implementation of the Act, and would not recognize SB 1149's "dual mandate" to utilities, to "both implement the steps of industry restructuring under the Act and be kept financially whole."[16] Similar to the electric industry restructuring of SB 1149, the RPS was designed to foster a significant transformation of the electric industry while at the same time doing "no harm" the utilities.

In 2009, HB 3039 enacted a solar VIR program, codified as ORS 757.365.[17] The solar VIR statute includes the following cost recovery provision: "All prudently incurred costs associated with compliance with this section are recoverable in the rates of an electric company."[18] The Commission implemented this language by approving cost recovery deferred accounts for PGE and Pacific Power "consistent with their current automatic adjustment clause practices."[19] For Idaho Power, which does not have a RAC, the Commission approved the company's request "to recover 100 percent of its costs through a rider mechanism similar to its currently approved Energy Efficiency Rider."[20]

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[15] *Id.* at 3.
[16] ***Id.***
[17] As amended by HB 3690 (2010).
[18] ORS 757.365(10).
[19] *See* OAR 860-084-0390; *In the Matter of Pub. Util. Comm'n of Or. Investigation into Pilot Programs to Demonstrate the Use and Effectiveness of Volumetric Incentive Rates for Solar Photovoltaic Energy Systems*, Docket No. UM 1452, Order No. 10-198 at 21 (May 28, 2010); *see also In the Matter of Portland Gen. Elec. Co. Application for Deferral of Expenses Associated with a Photovoltaic Volumetric Incentive Rate Pilot*, Docket No. UM 1482, Order No. 11-059 (Feb. 16, 2011) and *In the Matter of PacifiCorp, dba Pac. Power Application for Deferred Accounting*, Docket No. UM 1483, Order No. 11-021 (Jan. 12, 2011) (approving request for deferral of solar incentive program costs for PGE and Pacific Power; initial deferrals have been reauthorized every year).
[20] Order No. 10-198 at 21. Idaho Power's Energy Efficiency Rider allows it to collect 1.5 percent of base revenues for implementation of demand side management programs. *In the Matter of Idaho Power Co.*

In sum, the Commission has previously interpreted cost recovery language very similar to that in ORS 469A.120 and recognized that it supports recovery of actual costs through an automatic adjustment clause or deferred accounting.

2. SB 838's Inclusion of an Automatic Adjustment Clause for Investment in Plant Does not Limit the Commission's Discretion to Adopt the RRTM.

ICNU and CUB both argue that the context provided by ORS 469A.120(2) requires a reading of ORS 469A.120(1) that "dollar-for-dollar" recovery was contemplated for investment in plant through the automatic adjustment clause (AAC),[21] but not for variable costs.[22] The language and organization of the statute does not support this analysis, however, and there is no rational basis for treating the scope of recovery for fixed costs and variable costs differently. Section (1) of ORS 469A.120 establishes the scope of the costs recoverable (all prudently incurred costs); Section (2) provides "timely recovery" for a specific subset of those costs, and specifies the mechanism for recovery, an AAC to be established by the Commission. Taken together, the statute provides for recovery of *all* prudently incurred costs, and the difference between ORS 469A.120 Section (1) and Section (2) is merely the timing and method of recovery for a specific subset of RPS costs.[23]

Notably, the solar VIR statute was enacted in the same legislation as the solar capacity standard, codified as ORS 757.370. The solar capacity standard provides for

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Application for Adoption of its 2006 Integrated Resource Plan, Docket No. LC 41, Order No. 07-394 at 9 (Sept. 12, 2007).

[21] Throughout this brief, AAC is used to refer to the generic language in the statute directing the Commission to adopt an automatic adjustment clause, and RAC is used to refer to the renewable adjustment clause adopted by the Commission to implement the legislature's direction in the statute.

[22] CUB's Prehearing Brief at 7; ICNU's Prehearing Brief at 7.

[23] ORS 469A.120(1) provides "all prudently incurred costs associated with compliance with a renewable portfolio standard are recoverable in the rates of an electric company." ORS 469A.120(2) provides that the "Commission shall establish an automatic adjustment clause as defined in ORS 757.210 or another method that allows timely recovery of costs prudently incurred by an electric company to construct or otherwise acquire facilities that generate electricity from renewable energy sources and for associated electricity transmission."

recovery of all compliance costs through an automatic adjustment clause under ORS 469A.120.[24] Even though the cost recovery mandate in the solar VIR statute does not specifically refer to an AAC under ORS 469A.120 (unlike the solar capacity standard), the Commission still approved dollar-for-dollar recovery for all VIR program compliance costs.

3. The RRTM is Consistent with the Policy Principles regarding Cost Recovery in the Legislative History of SB 838.

CUB argues that the contextual analysis of ORS 469A.120(1) and (2) is further illuminated by consideration of the legislative history. Viewed as a whole, however, the legislative history of SB 838 demonstrates that it was not the legislature's intent to implement an RPS that utilities would ultimately subsidize. For example, then Commission Chair Lee Beyer provided the following testimony:

> It actually makes some sense, if you're asking the utilities to make an investment, a specific investment, and they're saying ok, if we have to make that to meet law, we want to make sure that we have the opportunity to recover those costs if they are prudently incurred. And I think that makes some sense.[25]

While Chair Beyer's testimony was specifically directed at the AAC, his logic is equally applicable to variable RPS compliance costs. The Joint Utilities' RPS compliance obligations do not terminate with acquisition of an RPS-eligible resource; instead the obligations are on-going, and increase with the amount of RPS compliant energy serving load to meet the compliance target of 25 percent served by renewable resources by 2025. As Chair Beyer said, "it makes sense" to provide recovery for specific costs that are incurred to meet the RPS.

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[24] ORS 757.370(5).

[25] House Committee on Energy and Environment, SB 838, Apr. 16, 2007, audio recording at approximately 1 hour, 25 minutes (oral testimony of Lee Beyer, Chair of the Public Utility Commission of Oregon).

4. The Commission has Discretion to Adopt a New Approach to Recovery of Variable RPS Compliance Costs.

Staff and CUB ultimately conclude that the Commission has the discretion to determine the appropriate method to provide an opportunity for recovery of variable costs.[26] The Joint Utilities agree that ORS 469A.120(1) does not mandate a particular design for the cost recovery mechanism for variable costs, as long as it provides an opportunity to recover all RPS compliance costs. Where SB 838 is silent, the Commission has discretion to fill in gaps to accomplish the policy of SB 838. For example, when developing the RAC, stipulating parties testified that, "while SB 838 is silent about the use of deferred accounting, for the purposes of their stipulation the Joint Parties have agreed that it may be used, and that the deferrals should not be subject to the ORS 757.259(5) earnings review." The Commission adopted the RAC as proposed by the stipulating parties, exercising its discretion to fill in pieces not explicitly provided for by the legislature, while allowing full cost recovery.[27] Similarly, where ORS 469A.120(1) is silent with regard to the method for recovery of variable costs, the Commission has discretion to fill in the missing pieces through adoption of the RRTM.

B. The RRTM Accurately Isolates and Allows Recovery of the Variable Costs of RPS Compliance.

In addition to their legal and policy arguments, Staff, CUB, and ICNU recommend that the Commission reject the RRTM on the basis of purported design flaws. As described below, the RRTM is a straightforward mechanism and the parties' concerns regarding its design are overstated. The Joint Utilities urge the Commission to find that the RRTM

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[26] Staff's Prehearing Brief at 4; CUB's Prehearing Brief at 8.
[27] *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 6 (Dec. 19, 2007).

proposal is a reasonable starting point to isolate and provide recovery for variable RPS compliance costs variances, subject to review and potential modification after three years of implementation.

1. It is Essential to Include PTCs in the RRTM.

ICNU argues that including PTCs in the RRTM may create asymmetrical recovery by providing an inaccurate level of Accumulated Deferred Income Tax (ADIT), because PTCs not claimed in a given year can reduce ADIT.[28] Importantly, because PTCs reduce ADIT only if they are not fully utilized, PacifiCorp's ADIT reflects no PTCs.[29] While PGE's ADIT reflects a small amount of PTCs, PGE agrees to adjust any PTC variance that flows through the RRTM to be net of changes in ADIT. This fully addresses ICNU's concern regarding inclusion of PTCs in the RRTM.

PTCs are a direct and quantifiable benefit of RPS compliant resources, which have always been reflected in the Joint Utilities' RACs.[30] It is contrary to ORS 469A.120(1) to flow the benefits of PTCs to customers on a dollar-for-dollar basis, without any way to timely reflect a reduction in these benefits. The RRTM would properly isolate and capture these cost variances. It is imperative to reflect PTC variances in the RRTM, even if it means severing them from the NPC variance component.

2. It is Essential to Reflect Market Prices in the RRTM.

Staff, CUB, and ICNU express a variety of concerns regarding the use of market prices in the RRTM. To be clear, the Joint Utilities are not proposing anything new or novel in using actual generation capacity and actual market prices to determine actual NPC. For

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[28] ICNU's Prehearing Brief at 18-19.
[29] PGE-PAC/200, Tinker-Dickman/16.
[30] *See, e.g.*, Order No. 08-548 at 4 ("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).

example, to implement situs assignment of the costs of Oregon's solar capacity standard, Pacific Power's PCAM trues-up the forecast credit for the value of the solar energy in the TAM with the actual value of the solar energy, using a similar calculation as proposed for the RRTM.[31]

Market prices have always been a key variable in determining NPC on both a forecast and actual basis. Wholesale revenue credits are a function of generation output and market prices. Both elements are forecast in annual NPC updates and both elements are subject to true-up in the PCAM. Similarly, in the case of catastrophic forced outages, deferred costs for replacement power are determined by considering actual market prices at the time of the outage, not the market prices forecast in rates.[32]

Staff and CUB complain that the risk of variance in RPS compliance costs is more attributable to variability in market prices rather than generation forecast variability.[33] But variances in either generation or market price (or both together) result in real costs to the utility and historically both components have contributed to variances in RPS compliance costs.

CUB argues that it is inappropriate for customers to bear the risk of market price error, because customers do not typically bear the risk of error in forecasting market price.[34] Staff also asserts that the RRTM shifts too much risk to customers.[35] The risk of error in

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[31] *In the Matter of PacifiCorp, dba Pac. Power 2013 Power Cost Adjustment Mechanism*, Docket No. UE 290, Order No. 14-357, App. A at 8 (Oct. 16, 2014); *In the Matter of PacifiCorp, dba Pac. Power 2014 Power Cost Adjustment Mechanism*, Docket No. UE 298, Initial Filing, Att. A. at 1 (May 15, 2015).
[32] *See, e.g.*, *In the Matter of Portland Gen. Elec. Co. Application for Deferred Accounting of Excess Power Costs Due to Plant Outage*, Docket No. UM 1234, Order No. 07-049 (Feb. 12, 2007) (using actual purchase price to determine costs of replacement power).
[33] CUB's Prehearing Brief at 9-11; Staff's Prehearing Brief at 6-7.
[34] CUB's Prehearing Brief at 9.
[35] Staff's Prehearing Brief at 7-8.

market price forecast is inherent in determining proper value of renewable resources and constitutes a legitimate cost of RPS compliance.

CUB argues that the Joint Utilities' inclusion of market price variance in the RRTM is contrary to the testimony provided by Pacific Power to the Oregon legislature: "when 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."[36] CUB asserts that the "Joint Utilities' proposal would now make renewable generation subject to market price risk and fuel price risk, which would add an unnecessary burden to customers not contemplated when SB 838 was enacted."[37] Yet, the Joint Utilities explained in their testimony that RPS resources are not modeled as "free energy." The Joint Utilities testified:

> The models used for the Joint Utilities' annual net power costs forecasts include the energy from RPS resources which results in an offset to net power costs, with a credit (or "negative cost") based on the utility's avoided cost of fuel, market purchases, or market sales. If the amount of actual wind generation or market rates are different than forecast, the negative cost of the RPS resources could be overstated or understated in prices.[38]

Moreover, the value of the benefit of RPS resources that is passed through to customers in the AUT and the TAM is determined by a forecast of market prices, which may be linked to variability in natural gas prices.

CUB argues that the use of third-party index, PowerDex, to determine market prices may have nothing to do with actual utility resource actions and expenses.[39] While the Joint Utilities believe that PowerDex is the most reasonable way to represent market prices, if the

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[36] CUB's Prehearing Brief at 12 (*citing* 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)).
[37] *Id.*
[38] *See* PGE-PAC/200, Tinker-Dickman/5.
[39] CUB's Prehearing Brief at 11.

Commission prefers the use of a different index, the Joint Utilities are open to consideration of alternatives.

3. Staff's Alternative Proposal Should be Rejected.

Staff claims that the RRTM shifts too much risk to customers, and states that if the Commission adopts a mechanism, it should exclude market price variability and include an earnings test.[40] As explained above, it is essential to include market price variances in the RRTM. In addition, an earnings test is unwarranted and inconsistent with the legislative mandate allowing for recovery of all prudently incurred costs of RPS compliance. Moreover, when the Commission adopted the RAC, it did not subject the RAC to earnings review.[41]

4. The RRTM Properly Isolates RPS Compliance Costs.

ICNU cites the difficulty associated with isolating RPS compliance costs as reason for rejecting the RRTM.[42] ICNU claims that the RRTM does not accurately value variable costs of RPS compliant resources because systems are operated as an integrated whole and the RRTM ignores system benefits and may create an inaccurate assessment of RPS-related power costs.[43] ICNU cites Pacific Power's testimony in docket UE 246 regarding the difficulty of isolating and quantifying the costs of wind variability. ICNU fails to mention that in docket UE 246, ICNU and other parties opposed using the PCAM to capture RPS compliance costs in part because it was overbroad and captured the system costs and benefits ICNU now complains are missing in the RRTM.[44] The Joint Utilities have developed the

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[40] Staff's Prehearing Brief at 7-8.
[41] Order No. 07-572 at 4 (order approving stipulation in which parties agreed that earnings review would not apply to the RAC).
[42] ICNU's Prehearing Brief at 15-16.
[43] *Id.*
[44] *In the Matter of PacifiCorp, dba Pac. Power, Request for a General Rate Revision*, Docket No. UE 246, Joint ICNU-CUB Prehearing Brief at 11 (Sept. 24, 2012).

RRTM proposal in response to the Commission's direction in docket UE 246 that RPS costs must be segregated from other NPC for recovery under SB 838.[45]

III. CONCLUSION

The RRTM closes the current recovery gap for RPS compliance cost variances and effectuates the plain language of ORS 469A.120(1). The RRTM is necessary, advances the policy goals of SB 838, properly isolates RPS compliance costs, and allows the Joint Utilities the opportunity for full cost recovery provided in ORS 469A.120(1). The design of the RRTM is straightforward and the Commission can further refine it by approving the RRTM subject to a design review after an initial three-year implementation period. Irrespective of the treatment of NPC variances under the RRTM, the Commission should include PTC variances in the RRTM.

Respectfully submitted this 19th day of October, 2015.

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[45] *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) ("We note that wind integration costs represent a small portion of all of Pacific Power's NPC, and even that portion is difficult to determine. While we acknowledge that ORS 469A.120(1) provides for recovery of prudently incurred SB 838 compliance costs, we find it unreasonable to adopt a straight dollar-for-dollar PCAM for the totality of Pacific Power's NPC to address appropriate recovery for costs that may amount to far less than 2 percent of that total-particularly when those costs may be difficult to quantify precisely.").