BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1662

In the Matter of	)
	)
PORTLAND GENERAL ELECTRIC COMPANY and PACIFICORP dba PACIFIC POWER	)
	)
Request for Generic Power Cost Adjustment Mechanism Investigation	)

PREHEARING BRIEF OF THE

CITIZENS' UTILITY BOARD OF OREGON

September 16, 2015

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Pursuant to Administrative Law Judge ("ALJ") Powers' Ruling issued July 9, 2015, the Citizens' Utility Board of Oregon ("CUB") submits its Prehearing Brief in docket UM 1662.

I. Background

This docket was opened at the request of Portland General Electric ("PGE") and PacifiCorp (collectively, "Joint Utilities") to review the ratemaking treatment of variable Renewable Portfolio Standard ("RPS")[1] compliance costs in each utility's power cost adjustment mechanism ("PCAM").[2] Fundamentally, the Joint Utilities argue that they are not currently recovering every dollar of prudently incurred costs associated with compliance with the RPS in rates because of the structure of the earnings test, deadbands

[1] The Renewable Portfolio Standard was enacted via _S.B. 838, 74th Leg., 2007 Reg. Sess. (Or. 2007).
[2] UM 1662 - PGE-PAC/100/Tinker-Dickman/2-3; PGE-PAC/200/Tinker-Dickman/2.

and sharing mechanisms in their respective power cost adjustment mechanisms ("PCAM").[3] They argue that a dollar-for-dollar recovery of variable RPS compliance costs is the only way to ensure that the utility recovers *all* prudently incurred costs, as permitted by ORS 469A.120.[4]

At the November 12, 2014 Public Meeting, the Commission approved the Joint Utilities' request and ordered an investigation to be opened to explore four issues: (1) isolation of RPS variable costs, (2) identification and quantification of RPS benefits, (3) recovery of variable costs directly attributable to RPS compliance, and (4) cost recovery design.[5]

i. Current Cost Recovery for RPS Compliance

The RPS is codified in ORS Chapter 469A. ORS 469A.120(1) provides that "all prudently incurred costs associated with compliance with a renewable portfolio standard are recoverable in the rates of an electric company." Currently, costs associated with RPS compliance are recovered in two ways—through the Renewable Adjustment Clause ("RAC") and through net power costs.[6]

The RAC allows utilities to recover (1) the return of and on capital costs of the renewable energy source and associated transmission, (2) forecasted operation and maintenance costs, (3) forecasted property taxes, (4) forecasted energy tax credits, and (5) other forecasted costs and cost offsets authorized by SB 838 and not captured in the

[3] UM 1662 - PGE-PAC/100/Tinker-Dickman/6.
[4] *Id.*
[5] Oregon Public Utility Commission Minutes of Public Meeting November 12, 2014 at 2. Accessed at http://www.puc.state.or.us/meetings/pmemos/2014/111214/PM%20Minutes%2011122014.pdf.
[6] UM 1662 - CUB/100/Jenks-Hanhan/4-6.

Utilities' annual power cost updates.[7] The purpose of the RAC is to avoid regulatory lag of investment costs.[8]

The Joint Utilities currently recover the net power cost ("NPC") impact of renewable generation through their respective NPC recovery mechanisms. For PGE, net power costs are forecasted in its Annual Update Tariff ("AUT"); for PacifiCorp, net power costs are forecasted in its Transition Adjustment Mechanism ("TAM"). Both PGE and PacifiCorp have a PCAM that compares actual net power costs to the forecasted net power costs. The PCAM is subject to deadbands, an earnings test, and sharing, which help to ensure that ratepayers are not taking on risk that shareholders are already compensated for and that customers are not bearing additional costs when the utility's earnings are reasonable.[9]

ii. The Joint Utilities' Proposal

On March 16, 2015, the Joint Utilities filed opening testimony proposing an automatic adjustment clause mechanism, called the Renewable Resource Tracking Mechanism ("RRTM"), which they argue will provide "a balanced opportunity to recover prudently incurred costs and pass through the full benefits associated with compliance with the Oregon RPS."[10] The Joint Utilities argue that the current cost recovery mechanisms for the NPC impact of renewable generation do not allow for the recovery of "all" costs of RPS compliance because of the deadbands, earnings test, and sharing in

[7] *Re Investigation of Automatic Adjustment Clause Pursuant to SB 838*, OPUC Docket No. UM 1330, Order No. 07-572 at 3 (Dec. 19, 2007).
[8] UM 1662 - CUB/100/Jenks-Hanhan/6.
[9] UM 1662 - CUB/100/Jenks-Hanhan/1-2.
[10] UM 1662 - PGE-PAC/100/Tinker-Dickman/7. CUB notes that although the Joint Utilities cite the pass through of benefits to customers with RPS compliance as a reason for their proposed RRTM, the impetus of this docket is their alleged significant under-recovery of RPS compliance costs. UM 1662 - PGE-PAC/100/Tinker-Dickman/1-2.

their respective PCAMs.[11] They argue that this is contrary to what was contemplated by the Oregon legislature and that they should be granted dollar-for-dollar recovery for the variable costs of renewable generation resources necessary for RPS compliance.[12] Despite the fact that the Joint Utilities have been recovering variable costs associated with renewable generation resources through their respective net power cost ("NPC") mechanisms since 2007, they now argue that changed circumstances, including the size of their respective renewable resource portfolios, support a change in cost recovery mechanisms.[13]

For utility-owned resources, the Joint Utilities propose to calculate NPC variance as "the difference between forecasted market value of output and actual market value of output,"[14] and as applicable, to calculate "the difference between forecasted and actual royalty payments and integration costs."[15] If the forecasted output and actual output are equivalent for any given hour, the power cost variance would be set to zero.[16] For contracted resources, the Joint Utilities propose to calculate NPC variance by determining the difference between forecasted output and margin and actual output and margin, with margin determined as the difference between the market price and the contract price.[17]

For the reasons discussed below, the Commission should reject the Joint Utilities' proposed RRTM.

[11] UM 1662 - PGE-PAC/100/Tinker-Dickman/6-7. The Joint Utilities also argue that neither the PCAM nor the annual NPC updates include recovery of or account for variations in production tax credits ("PTCs"). *Id.* at 6.
[12] UM 1662 - PGE-PAC/100/Tinker-Dickman/4-5.
[13] *Id.* at 5.
[14] *Id.* at 10.
[15] *Id.*
[16] *Id.*
[17] *Id.*

II. Argument

As stated above, the scope of this docket is limited to the four issues identified in Staff's Public Meeting Memo. The Joint Utilities must establish that they are able to isolate RPS variable costs, identify and quantify RPS benefits, and demonstrate that their proposed mechanism allows for the recovery of variable costs directly attributable to RPS compliance. The Joint Utilities have not met their burden in this docket, and therefore, the Commission should reject their RRTM proposal.

A. ORS 469A.120 does not require dollar-for-dollar recovery of variable RPS compliance costs

The Joint Utilities argue that the plain language of ORS 469A.120(1) supports their request for the RRTM.[18] They argue that in order to recover "all" prudently incurred costs, they must be allowed dollar-for-dollar recovery of variable costs.[19] The fundamental issue is the interpretation of the legislature's intent behind the statement that *all* prudently incurred costs are recoverable. Despite the Joint Utilities' claims to the contrary, the legislature's intent was not so straightforward.

The process for interpreting statutory meaning has been well established by the Oregon Supreme Court. In *State v. Gaines*, the Court articulated the three-step process it uses when interpreting a statute.[20] The first step is an examination of the text and context of the statute itself; the second step, at the court's discretion, is consideration of relevant legislative history offered by a party; and the final step is to apply general maxims of

[18] UM 1662 - PGE-PAC/100/Tinker-Dickman/4-6; PGE-PAC/200/Tinker-Dickman/2-3.
[19] UM 1662 - PGE-PAC/200/Tinker-Dickman/1-2.
[20] *State v. Gaines*, 346 Or. 160, 171-172 (2009).

statutory construction.[21] With regard to the context of the statute, the Court "includes other provisions of the same statute and other related statutes, as well as the preexisting common law and statutory framework within which the law was enacted."[22] With regard to legislative history, the Court has stated that "a party is free to proffer legislative history to the court, and the court will consult it after examining the text and context, even if the court does not perceive ambiguity in the statute's text, where that legislative history appears useful to the court's analysis."[23] The Court also explicitly recognized that legislative history could be used "to convince a court that superficially clear language actually is not so plain at all -- that is, that there is a kind of latent ambiguity in the statute."[24] In this case, the language at issue may seem straight-forward, but is plagued with latent ambiguity.

In relevant part, ORS 469A.120 states:

> **469A.120 Cost recovery by electric companies.** (1) Except as provided in ORS 469A.180 (5), all 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.
>
> (2) The Public Utility 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. Notwithstanding any other provision of law, upon the request of any interested person the commission shall conduct a proceeding to establish the terms of the automatic adjustment clause or other method for timely recovery of costs. The commission shall provide parties to the proceeding

[21] *Id.*
[22] *State v. Stallcup*, 341 Or. 93, 99 (2006) (internal citation omitted).
[23] *Gaines*, 346 Or. at 172.
[24] *Id.*

> with the procedural rights described in ORS 756.500 to 756.610, including but not limited to the opportunity to develop an evidentiary record, conduct discovery, introduce evidence, conduct cross-examination and submit written briefs and oral argument. The commission shall issue a written order with findings on the evidentiary record developed in the proceeding.

The plain language of the statute, as conceded by the Joint Utilities, does not contemplate an automatic adjustment clause for variable costs as it does for fixed costs.[25] The context of the statute, however, makes clear that the Oregon legislature did not intend that variable cost recovery be limited to dollar-for-dollar recovery in order to allow for the recovery of "all" prudently incurred costs.

When the legislature intended dollar-for-dollar recovery of certain prudent costs, it was explicit as evidenced by the automatic adjustment clause for construction and other fixed costs as required by ORS 469A.120(2). Had the legislature intended for dollar-for-dollar recovery of variable costs, it could easily have written so into the statute as it did with fixed costs. The fact that it declined to do so makes clear that the legislature appreciated the difference between dollar-for-dollar recovery mechanisms and other cost recovery mechanisms available to the Commission, but obviously believed that both types of mechanisms allowed for the recovery of "all" prudently incurred costs.

Although the context of the statute makes clear that the legislature did not intend to limit the Commission to a dollar-for-dollar recovery mechanism for variable costs, the legislative history of SB 838's cost recovery provision is also instructive as to the legislature's intent and stakeholder understanding. As the Joint Utilities testify, at least some SB 838 stakeholders clearly understood that variable costs and benefits from RPS

[25] UM 1662 - PGE-PAC/200/Tinker-Dickman/4.

compliance would receive ratemaking treatment through existing mechanisms.[26] The Joint Utilities argue that "[t]he fact that stakeholders did not recognize the potential need for separate recovery of variable costs associated with RPS compliance does not demonstrate that stakeholders, or more importantly, the legislature, intended for utilities to be limited in their ability to recovery those variable costs."[27] By the same token, the stakeholders, including PGE and PacifiCorp, also understood that from the outset, not every last dollar of prudently incurred variable compliance costs would be recovered because variable power costs have traditionally been recovered through a forecast.[28] To now claim that the present recovery mechanism is inconsistent with the RPS is disingenuous.

Although CUB and the Joint Utilities are in agreement that the Commission has discretion with regard to cost recovery for variable RPS compliance costs,[29] there is nothing in ORS 469A.120 that requires dollar-for-dollar recovery of variable net power costs in order to be consistent with the concept that all prudently incurred costs are recoverable. Furthermore, even if the Commission were to determine that dollar-for-dollar recovery was appropriate, it should nevertheless reject the Joint Utilities' RRTM proposal for the reasons discussed below.

B. The design of the RRTM is one-sided, flawed and contrary to sound ratemaking policy

The Commission made clear that any change to the cost recovery mechanism must isolate variable costs and identify, and quantify benefits attributable to RPS

[26] UM 1662 - PGE-PAC/200/Tinker-Dickman/4.
[27] *Id.*
[28] UM 1662 - CUB/100/Jenks-Hanhan/4.
[29] *Id.* at 6.

compliance so that a true net of costs directly attributable to RPS compliance would be recoverable in rates.[30] The Joint Utilities argue that the RRTM appropriately isolates RPS variable costs because it covers "only those resources eligible for compliance with the RPS and uses verifiable generation and market data to track the actual variable costs and benefits associated with RPS compliance, including [production tax credits]."[31] For a number of reasons, CUB testified that the Joint Utilities' proposal is one-sided and as such, falls far short of isolating RPS variable costs and quantifying RPS compliance benefits.

First, CUB's Reply Testimony demonstrates that the RRTM could inappropriately shift market price risk to ratepayers because price changes in the RRTM could "primarily be related to market price forecasting, not wind forecasting errors."[32] The Joint Utilities dismiss CUB's claims, stating that "[b]y authorizing recover [sic?] of all prudently incurred costs of RPS compliance, the legislature made the choice to require customers to bear the costs of SB 838. The RRTM is consistent with SB 838's assignment of compliance risk to customers."[33] As argued above, the legislature did not intend or require dollar-for-dollar recovery of variable RPS compliance costs. There is no evidence in the record in this case that demonstrates that the legislature intended to alter the traditional tenants of ratemaking for variable power costs in Oregon when the RPS was enacted. As CUB testified, customers do not typically bear the risk of errors made in forecasting prices.[34]

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[30] Public Utility Commission of Oregon Staff Report, November 12, 2014 Public Meeting at 5 (Nov. 5, 2014).
[31] UM 1662 – PGE-PAC/100/Tinker-Dickman/13.
[32] UM 1662 - CUB/100/Jenks-Hanhan/10-11.
[33] UM 1662 - PGE-PAC/200/Tinker-Dickman/6.
[34] UM 1662 - CUB/100/Jenks-Hanhan/4.

The absurdity of the extension of the Joint Utilities' argument becomes clear when one considers their proposal for calculating net power costs for utility-owned resources. Under the Joint Utilities' proposal, net power costs for utility-owned resources would equal forecasted wind x forecasted price +/- actual wind x actual price.[35] If the forecasted output and actual output are equivalent for any given hour, the Joint Utilities propose to set the power cost variance to zero.[36] Stated another way, if forecasted wind equals actual wind, PGE and PacifiCorp would ignore the market price portion of the equation and simply set the power cost variance to zero. This means that absent this adjustment, even if wind was forecasted perfectly, customers would still face a surcharge. What if the difference between forecasted wind and actual wind was responsible for 1% of the power cost variance, and the difference in market prices was responsible for 99%? Under the RRTM, the utilities would still get 100% of the variance even though the wind forecast was 99% correct. In short, a power cost surcharge could be almost exclusively triggered by an incorrect forecast in market prices rather than an incorrect forecast for wind variances, yet customers would still be responsible for 100% of the variance. Such a construct is patently unfair and unbalanced to customers, and does not isolate the variable costs of RPS compliance.

CUB Exhibit 103 demonstrates that this is not a remote or unfounded concern. For PacifiCorp, the risk associated with wind forecasting error pales in comparison to the risk associated with market prices—in 2011 and 2012, PacifiCorp's wind forecast variance was 7% and -3%, respectively, while its market price variance was 22% and

[35] UM 1662 - PGE-PAC/100/Tinker-Dickman/10.
[36] *Id.*

27%, respectively.[37] This means that had the RRTM been in place for PacifiCorp for 2011 and 2012, customers would have paid costs much more heavily associated with market price risk than wind forecasting error. In 2013, the wind forecasting error was -1% and the market price error rounded to 0%, thereby negating the need for a true-up.[38]

Second, the Joint Utilities propose to use the hourly market to value the wind forecast error, despite the fact that they do not rely exclusively on hourly spot market purchases to manage the risk of wind forecasting errors.[39] The Joint Utilities justify the use of hourly market prices because they are "verifiable and are published by an independent third-party,"[40] but acknowledge that "there are other valuation methods that could be used for RPS generation but they would make the RRTM formula unnecessarily complex without adding equivalent value."[41] The Commission, however, was clear—the Joint Utilities must be able to isolate the correct RPS variable costs that are directly attributable to RPS compliance.[42] As CUB testified, utilities have several tools to manage risk, and they update forecasts of loads and resources regularly.[43] To the extent that the Commission were to adopt a mechanism allowing dollar-for-dollar recovery of variable RPS compliance, it should require a utility to actually track how it managed the risk of wind forecast errors, rather than simply rely on data that has little to do with the resource actions taken by the utility in managing forecast errors.[44]

[37] UM 1662 - CUB/100/Jenks-Hanhan/11.
[38] *Id.*
[39] *Id.* at 14-15.
[40] UM 1662 - PGE-PAC/200/Tinker-Dickman/11.
[41] *Id.*
[42] Public Utility Commission of Oregon Staff Report, November 12, 2014 Public Meeting at 5 (Nov. 5, 2014).
[43] UM 1662 - CUB/100/Jenks-Hanhan/14.
[44] *Id.* at 15.

Third, CUB raised a concern that the RRTM would add fuel price risk to renewables.[45] As CUB explained, "[w]hen the utilities request recovery of the variance between forecasted and actual market prices, they are valuing renewables based on the market price" which takes away a substantial benefit of renewables—no fuel or variable price risk.[46] This is contrary to what PacifiCorp testified 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."[47] 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.[48] The RRTM could allow customers to be surcharged for costs primarily related to a change in market prices due to a change in natural gas prices, while telling them that the surcharge is associated with renewables.[49] In 2008, PacifiCorp's actual wind generation exceeded its forecast by 30 GWh.[50] This extra power that had no production cost – it did not burn fuel. Yet, under the RRTM, customers would face a surcharge for this extra, zero-cost power because the changes in the market price of natural gas and electricity affected the "value" of the wind.[51] The surcharge would be caused by changes in natural gas and electricity prices, not because renewable production was under-forecasted.

[45] *Id.* at 12-13.
[46] *Id.*
[47] UM 1662 - PGE-PAC/200/Tinker-Dickman/5, citing to House Committee on Energy and Environment, April 18, 2007 Public Hearing, Measure SB 838, Oral Testimony of Brent Gale, PacifiCorp at approximately 1 hour 24 minutes.
[48] UM 1662 - CUB/100/Jenks-Hanhan/13.
[49] *Id.* at 13-14.
[50] UM 1662 – PGE-PAC/200/Tinker-Dickman/13.
[51] *Id*.

Fourth, CUB testified that it is concerned about the fact that PGE's AUT already has an adjustment for wind forecast error, which could lead to double-recovery by PGE if it were granted dollar-for-dollar recovery of RPS compliance costs.[52] Specifically, in PGE's AUT there is $0.65/MWh adder attached to wind production as a forecast element of the wind forecast error.[53] The Joint Utilities dispute this, arguing that the adjustment in PGE's AUT represents the "cost of the changes necessary in PGE's non-wind resource portfolio and market position that result from the need to re-optimize PGE's system in an effort to accommodate the differences between the day-ahead and hour-ahead forecasts for wind generation."[54] The fact that PGE has this cost adder in the AUT, however, demonstrates that PGE manages its wind resources using its system, not simply the spot market. Therefore, including an adder to account for the cost to the "system" from accommodating the wind variability and adding a surcharge to recover the actual "value" of the wind variability, assuming it is managed only with spot market purchases and sales, would lead to a scenario in which customers are charged twice for PGE's management of wind variability.

Fifth, the Joint Utilities claim that because of their respective cost recovery mechanisms, including their PCAMs, "if variances in intermittent generation produce significant benefits over forecast (because, for example, actual wind production increases)" customers are not likely to receive these benefits.[55] CUB agrees. Net power costs are set on a forecasted basis with the utility bearing the risk of the forecast until the deadbands in the PCAM are reached. That risk, however, falls both ways. A utility can

[52] *Id.* at 11-12.
[53] *Id.* at 12.
[54] *Id.* at 15.
[55] UM 1662 - PGE-PAC/100/Tinker-Dickman/6.

under-recover or over-recover its actual costs. This is an important incentive. A utility that can manage its actual power costs within the forecasted rates established in the AUT and TAM can reap a reward. If the forecasted rates were based on strong analysis and modeling of power costs, then the rates are fair and reasonable, and customers are not harmed by paying those rates, even if actual costs are below the forecast.

Finally, the Joint Utilities' argument that the under-recovery problem was previously minimal in part due to the fact that PGE's PCAM was new and PacifiCorp's was not yet enacted is a red herring.[56] Even if PGE's PCAM was new, the parties certainly understood the mechanics of net power cost recovery, which include the use of forecasts and earnings tests, deadbands and sharing. Even if the impact was less than it is today, at no point since the RPS was enacted have the utilities received dollar-for-dollar recovery of these costs, and there is no evidence on the record that the Joint Utilities' had an understanding that dollar-for-dollar recovery was expected.

C. The Commission has rejected similar proposals in the past

As CUB and the Industrial Customers of Northwest Utilities ("ICNU") pointed out in testimony, the Commission has rejected similar attempts by the utilities in the past to shift the risk of managing their systems to customers.[57] In a recent PacifiCorp general rate case, UE 246, PacifiCorp asked for a PCAM with dollar-for-dollar recovery of all power costs based, in part, on the same reasoning present in this case—a guarantee of recovery of all prudently incurred RPS compliance costs coupled with the under-recovery of net power costs due primarily to the inability to accurately forecast wind generation

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[56] *See* UM 1662 – PGE-PAC/100/Tinker-Dickman/5.
[57] UM 1662 – CUB/100/Jenks-Hanhan/8-10; ICNU/100/Mullins/4-6.

and integration of renewables.[58] The Commission thoughtfully rejected PacifiCorp's proposal, establishing a PCAM that included an earnings test, deadbands, and sharing.[59]

CUB also recognizes that the RRTM will shift some hydro risk from the utility to its customers. RPS eligible resources include a significant volume of hydro. The proposed mechanism would shift the hydro risk to customers, despite the fact that the Commission has explicitly rejected proposals that would have the same effect in the past.[60] Nothing in the Joint Utilities' proposal should persuade the Commission to depart from its long-standing policy of not shifting the risk of hydro to customers.

III. Conclusion

For the forgoing reasons, CUB respectfully requests that the Commission deny the Joint Utilities' request for dollar-for-dollar recovery of renewable resource costs

Respectfully submitted,

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[58] UM 1662 - CUB/100/Jenks-Hanhan/8-9.
[59] *In re PacifiCorp*, Docket No. UE 246, OPUC Order No. 12-493 at 13 (Mar. 1, 2012).
[60] UM 1662 - CUB/100/Jenks-Hanhan/9-10.