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March 16, 2015

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
3930 Fairview Industrial Dr. S.E.
Salem, OR 97302-1166

Attn: Filing Center

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

PacifiCorp d/b/a Pacific Power (PacifiCorp) submits for filing the Joint Testimony of Jay Tinker and Brian Dickman on behalf of Portland General Electric Company and PacifiCorp.

Please direct any informal inquiries to Patrick Hager at (503) 464-7580 or Natasha Siores at (503) 813-6583.

Sincerely,

R Bryce Dalley /NCS

R. Bryce Dalley
Vice President, Regulation

Enclosures

Docket No. UM 1662
Exhibit PAC/100
Witnesses: Tinker-Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Joint Testimony of

Portland General Electric Company – Jay Tinker
and
PacifiCorp – Brian S. Dickman

March 2015

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PURPOSE AND SUMMARY

Q. Please state your names, positions, and relevant professional history.

A. My name is Jay Tinker. I am the Director of Rates and Regulatory Affairs at Portland General Electric Company (PGE). My name is Brian S. Dickman. My title is Director, Net Power Costs at PacifiCorp d/b/a Pacific Power (Pacific Power). Our qualifications appear at the end of our testimony.

Q. What is the purpose of your testimony?

A. Our testimony supports a joint request by PGE and Pacific Power (Joint Utilities) for a new regulatory approach to the variable costs of compliance with Senate Bill (SB) 838, codified in ORS Chapter 469A. SB 838 established Oregon's Renewable Portfolio Standard (RPS), which requires the Joint Utilities to deliver an increasing percentage of their electricity from renewable resources. The Joint Utilities propose to track and recover renewable resource costs separately from other variable costs in the companies' net variable power costs (NPC), by removing renewable resources from their Power Cost Adjustment Mechanisms (PCAM) and reflecting all variable benefits and costs of those resources through an annual supplemental tariff filing called the Renewable Resource Tracking Mechanism (RRTM).

Q. Please summarize your testimony.

A. In the eight years since the RPS was enacted and implemented, the Joint Utilities have added many new renewable resources to comply with the law. The actual variable costs and benefits of these resources are not reflected in the Joint Utilities' rates, given the challenges of forecasting intermittent generation and the current design of the PCAM. As a result, the Joint Utilities have significantly under recovered their RPS compliance costs. It is consistent with the policy underlying SB 838 to allow the Joint Utilities to separately track and reflect in rates the variable costs and benefits of renewable resources through the RRTM. The RRTM is straightforward, recovering the variance between forecast and actual renewable generation and market prices. It is designed to operate with the Joint Utilities' annual NPC updates and PCAM and does not change those existing mechanisms.

BACKGROUND

Q. Please provide the background on this docket.

A. On June 19, 2013, PGE and PacifiCorp asked the Public Utility Commission of Oregon (Commission) to establish a generic docket to examine policies and design of the PCAM in place for both companies. After communicating with interested parties, including Commission Staff (Staff), the Citizens' Utility Board of Oregon (CUB), and the Industrial Customers of Northwest Utilities (ICNU), the Joint Utilities modified their request in a letter to the Commission dated March 21, 2014. Instead of a general reevaluation of the PCAM, the Joint Utilities proposed to narrow the scope of the Commission's investigation to a review of the ratemaking treatment of variable RPS compliance costs.

Q. Did Staff support the Joint Utilities' modified request to open this investigation?

A. Yes. In a Staff Report dated November 5, 2014, Staff recommended "that the Commission open an investigation into the treatment of variable costs that are a direct result of compliance with SB 838/ORS Ch. 469A." Staff noted that the Commission had not yet considered this policy question, the issue was important, and the dollars at stake were material.

Q. Did Staff identify the issues to be addressed in this docket?

A. Yes. Staff's Report proposed review of four issues:

> 1. Isolation of RPS Variable Costs
> To date a reliable mechanism has not been agreed upon to isolate the variable costs that are directly attributable to RPS compliance. The regulatory principle of cost causation compels us to first clearly identify these costs.
>
> 2. Identification and Quantification of RPS Benefits
> As with cost, benefits attributable to RPS compliance needs to be identified, isolated, and quantified before proper regulatory treatment can be applied. In the end, it is the net costs directly attributable to RPS compliance that are subject to potential recovery.
>
> 3. Discussion of Recovery
> From testimony in prior rate cases, Staff concludes that there is not a consensus among concerned parties that variable costs directly attributable to RPS compliance should be recovered outside of the PCAM, nor is there agreement that this cost be should be given any special recovery treatment.
>
> 4. Cost Recovery Design
> In the event that the Commission decides separate recovery of RPS compliance variable cost is warranted, a recovery mechanism must be created that does not materially alter the current operation of the PCAM and RAC.[1]

Q. Did the Commission approve Staff's recommendation as proposed?

A. Yes. At its November 12, 2014 Public Meeting, the Commission approved Staff's recommendation and opened this investigation.

Q. Did PGE raise a similar issue in its last general rate case filing, docket UE 283?

A. Yes. PGE proposed an RPS "carve out" in docket UE 283. That case was settled without resolution of this issue.

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[1] Public Utility Commission of Oregon Staff Report, November 12, 2014 Public Meeting at 5-6 (Nov. 5, 2014).

STATUTORY AND POLICY SUPPORT FOR THE RRTM

Q. When the Oregon Legislature enacted SB 838 requiring the Joint Utilities to comply with an RPS, did it also provide for recovery of compliance costs?

A. Yes. The Joint Utilities' proposal is based on the language of Section 13 of SB 838, Cost Recovery by Electric Companies, codified at ORS 469A.120(1) which states that "all prudently incurred costs associated with the compliance with a renewable portfolio standard are recoverable in the rates of an electric company[.]" SB 838 goes on to elaborate on the types of related costs that should also be recoverable:

> [I]ncluding 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 and other costs associated with transmission and delivery of qualifying electricity to retail electricity customers.

Q. Did SB 838 specify the type of mechanism by which the Joint Utilities could timely recover their prudently incurred compliance costs?

A. In part. For the costs to "construct or otherwise acquire" renewable resources and for associated transmission, ORS 469A.120(3) provides that the Commission shall establish an automatic adjustment clause, or another method, that allows for the timely recovery of prudent costs. For the other costs of compliance, the statute did not identify a specific recovery mechanism.

Q. To implement SB 838, did the Commission establish an automatic adjustment clause that allows recovery of the construction and acquisition costs of renewable resources?

A. Yes. The Commission established the Renewable Adjustment Clause (RAC), which allows the Joint 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 an annual power cost update.[2]

Q. In implementing SB 838, did the Commission establish a specific recovery mechanism for the NPC impact of renewable generation?

A. No. The Commission relied on the Joint Utilities' general NPC recovery mechanisms to capture the variable costs and benefits of their renewable generation resources.

Q. Have general NPC recovery mechanisms allowed the Joint Utilities to fully recover their variable RPS compliance costs?

A. No. The current regulatory framework allows for a level of costs and benefits to be included in customer prices as part of a regulatory proceeding such as a general rate case or annual NPC update filing. But these forecasts often vary significantly from actuals due to uncontrollable circumstances such as weather conditions. For instance, wind generation may be greater than or less than forecasted, reducing or increasing overall NPC and the amount of production tax credits (PTCs) generated.

Q. Have the Joint Utilities' circumstances changed since 2007 when the Commission first implemented SB 838?

A. Yes. In 2007, the Joint Utilities' renewable resource portfolios were a fraction of their current size; they had limited experience integrating, shaping, and firming a large amount of renewable resources in their systems; PGE's PCAM was newly approved; and PacifiCorp did not yet have a PCAM. Importantly, neither company

[2] *See Re Investigation of Automatic Adjustment Clause Pursuant to SB 838*, Docket No. UM 1330, Order No. 07-572 at 3 (Dec. 19, 2007).

had experience in using their general NPC recovery mechanisms to track the variable costs and benefits of compliance with SB 838.

Q. Does the PCAM allow for these costs to be recovered?

A. No. Although certain of these costs are eligible for recovery through the PCAM, the current design of the PCAM does not allow recovery of all prudently incurred variable costs associated with renewable energy resources used to meet Oregon's RPS. This is because the PCAM evaluates the Joint Utilities' overall actual NPC compared to the forecast established in the companies' annual NPC updates. The variance is then subject to deadbands, an earnings test, and sharing. Additionally, neither the PCAM nor the annual NPC updates include recovery of or account for variations in PTCs.

Q. Under the current approach, if variances in intermittent generation produce significant benefits over forecast (because, for example, actual wind production increases), do customers receive these benefits?

A. No. Under the current designs of PacifiCorp's Transition Adjustment Mechanism (TAM), PGE's Annual Update Tariff (AUT), and the Joint Utilities' PCAM, customers are not likely to see any benefits associated with positive variances in variable compliance costs.

Q. Based on the Joint Utilities' experiences over the last eight years, is there a need to change to the treatment of variable compliance costs and benefits?

A. Yes. The Joint Utilities' general NPC recovery mechanisms are inadequate to account for the variable costs and benefits associated with SB 838 compliance. For example, for the years 2007 through 2013, the net market value of PacifiCorp's wind generation reflected in the TAM has exceeded actuals by an average of $31.6 million per year. Under the TAM and PCAM, these variations were fully absorbed by the company.

PGE has experienced similar variances associated with wind. For example, from 2010 to 2013, forecasted amounts included as part of the AUT deviated from actuals by up to $24 million in a given year. These deviations are not reflected in customer rates due to the operation of the PCAM.

This data shows that the Joint Utilities are not currently recovering the variable costs associated with renewable resources used to comply with the RPS.

Q. Why should the Commission act now to change to the treatment of variable compliance costs?

A. After eight years, it is clear that the current approach does not permit the Joint Utilities to recover their variable costs of compliance with SB 838, or to credit full variable benefits to customers. This problem will only become worse as the Joint Utilities' renewable energy requirements increase to 25 percent of retail load in 2025.

RRTM PROPOSAL

Q. What is the RRTM proposal?

A. The RRTM is a mechanism allowing the Joint Utilities to separate renewable resources from the PCAM and pass the variable benefits and costs of those resources through the Joint Utilities' respective Renewable Adjustment Clause tariffs (PGE Schedule 122 and PacifiCorp Schedule 202) or other supplemental tariff filing. The RRTM provides a balanced opportunity to recover prudently incurred costs and pass through the full benefits associated with compliance with the Oregon RPS.

Q. Does the RRTM include all of the costs associated with RPS-compliant resources?

A. No. The true costs of owning and operating renewable resources go well beyond their impact on NPC. The Joint Utilities are not seeking recovery related to variances in operating expenses nor attempting at this time to fully isolate and recover all costs related to the self-integration of RPS-compliant resources. We are seeking the opportunity to recover prudently incurred NPC and PTCs and also return additional value (reduced NPC or greater PTCs) to customers.

Q. Do the Joint Utilities have specific suggestions on the design and implementation of the RRTM?

A. Yes, but we recognize that the circumstances of each utility may warrant design differences and look forward to engaging with parties on the appropriate design.

Q. Please describe the RRTM.

A. The Joint Utilities propose to use the RAC, or other agreed upon tariff, to refund to or collect from customers variances in NPC (output, market value, purchased integration, and royalties) and related PTCs for RPS-compliant resources. The refund or collection through the RAC would be included as an adjustment to the Joint Utilities' Results of Operations report, thereby reducing or increasing the regulated return on equity for the year. Finally, the forecasted and actual NPC would be removed from the PCAM (Schedule 126 for PGE and Schedule 206 for PacifiCorp) for purposes of determining refunds or collections under the PCAM.

Q. Which resources would this proposal cover?

A. The Joint Utilities' proposal applies to renewable resources used for compliance with the RPS. Table 1 below contains a list of these resources as of the date of this filing.

Q. Does the RRTM cover contracts with Qualifying Facilities (QFs)?

A. Yes, as long as the QF is RPS compliant and the utility retains the renewable energy certificates associated with the QF.

Table 1
Renewable Resources

PGE—Owned Assets:	PGE—Contracts:
• Biglow Canyon • Tucannon River • Low Impact Hydro and Hydro Upgrades	• Vansycle Wind • Klondike Wind • Outback Solar • Bellevue Solar • Yamhill Solar • Sunway II & III
Pacific Power—Owned Assets: • Dunlap 1 • Foote Creek 1 • Glenrock • Glenrock 3 • High Plains • McFadden Ridge • Seven Mile Hill • Seven Mile Hill 2 • Goodnoe Hills • Leaning Juniper 1 • Marengo 1 • Marengo 2 • Low Impact Hydro and Hydro Upgrades • Solar Capacity Standard Resources	Pacific Power—Contracts: • Chevron Wind • Mountain Wind 1 • Mountain Wind 2 • Rock River Wind • Three Buttes Wind • Top of the World • Wolverine Creek • Combine Hills • Foote Creek 2 • Foote Creek 3 • Solar Capacity Standard Resources

Q. Does this proposal alter the AUT or TAM?

A. No. The Joint Utilities will continue to make annual filings to update the forecast of NPC in rates under the AUT or TAM.

Q. What process do you recommend for the RRTM?

A. The proposed steps are:

- The Joint Utilities each individually establish an NPC forecast for year one
- Actual costs are tracked for year one

- During year two, the variances between forecasted and actual costs related to renewable resources in year one are calculated and removed from each utilities' PCAM
- The Joint Utilities each individually file to include any variance in rates effective January 1 of year three

This process repeats annually.

Q. How will NPC variances be determined?

A. For utility-owned resources, the NPC variance is calculated as the difference between forecasted market value of output and actual market value of output. As applicable, the difference between forecasted and actual royalty payments and integration costs will also be calculated. Additionally, if forecasted and actual output is equivalent for any given hour, the power cost variance will be set to zero.

For contracted resources, the NPC variance will be determined by calculating 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. Table 2 below summarizes the variables used for developing the variances:

Table 2
Variables

Variables for Determining the Forecast	
Owned Assets: • Generation from Final AUT/TAM filing • Market Prices from Final AUT/TAM filing • Royalty Payments (if applicable) • Integration Costs (if applicable)	Contracts: • Generation from Final AUT/TAM filing • Contracted Price ($/MWh) from Final AUT/TAM filing • Market Prices
Variables for Determining Actuals	
Owned Assets: • Actual Generation • Actual Market Prices • Actual Royalty Payments and Integration Costs (if applicable)	Contracts: • Actual Generation • Actual Contracted Price ($/MWh) • Actual Market Prices

Q. Why is market price the best value to use for determining the variances?

A. Both power cost forecasting and actual operations are based on the economic dispatch of resources. In other words, the Joint Utilities' power operations economically dispatch resources to minimize power costs, as do their respective power cost forecasting models. The NPC included in customers' rates is reduced by the forecast value of the RPS-compliant resources. To the extent that forecast value is overstated, customers' rates will not reflect the true cost of service including the resources for RPS compliance. If the actual generation from RPS-compliant resources does not match the power cost forecast, the Joint Utilities must go to the market to either purchase the deficit or sell the surplus. Additionally, if there is surplus owned generation that is "in the money" (marginal cost is less that marginal revenue) to meet the deficit, this is generation that would have otherwise been sold at market price, reducing overall power costs.

Q. What do the Joint Utilities propose using as a basis for market price?

A. The Joint Utilities propose using an established, third-party hourly index for their relevant market hubs. The Joint Utilities will use the best available hourly market data. Due to the intra-hour variability of RPS-compliant resources such as wind, this is the most accurate representation of the costs to replace deficit RPS-compliant resources or the value of surplus generation sales.

Q. Please explain how the RRTM and PCAM interact.

A. The Joint Utilities will continue to make annual NPC filings (AUT/TAM). The proposed RRTM would not change this. Consistent with the methodology used to determine the amount subject to the RRTM (i.e., both the forecast and actuals), the

Joint Utilities would include an adjustment in their respective PCAM calculations to remove both the forecast and actual renewables power costs. Following this approach (1) removes the possibility for double-counting by applying both the PCAM and RRTM to the same underlying costs, and (2) enables the PCAM to continue to operate as adopted by the Commission for the non-renewable portion of the Joint Utilities' power costs.

Q. How will PTC variances be determined?

A. The Joint Utilities will calculate the difference between actual PTCs generated and those forecasted to be generated in the most recent general rate case. The forecasted PTCs will be valued at the $/MWh rate used in the most recent general rate case while actual PTCs will be valued at the $/MWh rate as established by the Internal Revenue Service for the year in question.

Q. Will these variances accrue interest?

A. Yes. Variances will accrue interest at the Joint Utilities' authorized cost of capital until the funds begin being amortized. While this initial proposal calls for annual revisions to rates, a structure (such as a dollar limit the accrued variances must reach before customers are credited or charged) could be put in place to reduce the frequency of price changes for customers.

Q. Will the PCAM continue to operate as adopted by the Commission following implementation of the RRTM?

A. Yes. The PCAM will continue to operate as adopted by the Commission, with deadbands, an earnings test, and sharing on non-RPS-related net variable power costs.

Q. Does the RRTM address the four issues Staff outlined for review in this docket?

A. Yes. The first two issues are the isolation of RPS variable costs and the identification and quantification of RPS benefits. The RRTM 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 PTCs.

The third and fourth issues are a discussion of recovery and the design of cost recovery. The RRTM satisfies the cost recovery mandate of ORS 469A.120 and provides a balanced approach to reflecting variable RPS costs and benefits in rates. The RRTM is designed in a manner that is fully compatible with the current operation of the Joint Utilities' annual NPC updates and PCAM. From a policy perspective, the RRTM is aligned with the RPS and furthers its important objectives.

QUALIFICATIONS

Q. Mr. Tinker, please describe your qualifications.

A. I received a Bachelor of Science degree in Finance and Economics from Portland State University in 1993 and a Master of Science degree in Economics from Portland State University in 1995. In 1999, I obtained the Chartered Financial Analyst (CFA) designation. I have worked in the Rates and Regulatory Affairs department since 1996.

Q. Mr. Dickman, please describe your qualifications.

A. I received a Master of Business Administration from the University of Utah with an emphasis in finance and a Bachelor of Science degree in accounting from Utah State University. Prior to joining the Company, I was employed as an analyst for Duke

Energy Trading and Marketing. I have been employed by the Company since 2003 including positions in revenue requirement and regulatory affairs, and I assumed my current role managing the Company's net power cost group in March 2012. I have filed testimony in proceedings before the public utility commissions in California, Idaho, Oregon, Utah, and Wyoming.

Q. Does this conclude your testimony?

A. Yes.