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June 22, 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 Rebuttal 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 Erin Apperson at (503) 813-6642.

Sincerely,

R Bryce Dalley / eaa

R. Bryce Dalley
Vice President, Regulation

Enclosures

Docket No. UM 1662
Exhibit PAC/200
Witnesses: Tinker-Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Joint Rebuttal Testimony of

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

June 2015

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PURPOSE AND SUMMARY

Q. Are you the same Jay Tinker and Brian S. Dickman who submitted joint direct testimony in this docket for Portland General Electric Company (PGE) and PacifiCorp d/b/a Pacific Power (Pacific Power), collectively referred to as the Joint Utilities?

A. Yes.

Q. What is the purpose of your joint rebuttal testimony?

A. Our testimony responds to objections and alternatives to the renewable resource tracking mechanism (RRTM) raised by Mr. John Crider on behalf of the Staff of the Public Utility Commission of Oregon (Staff). We also respond to the objections to the RRTM raised by Mr. Bob Jenks and Ms. Nadine Hanhan, on behalf of the Citizens' Utility Board of Oregon (CUB), and Mr. Bradley G. Mullins, on behalf of the Industrial Customers of Northwest Utilities (ICNU).

Q. Please summarize your joint testimony.

A. Our joint testimony responds to the parties' positions by addressing the following points:

First, the plain language of SB 838 allows for a true-up mechanism like the RRTM. The statute states that *all* renewable portfolio standard (RPS) compliance costs are recoverable, which necessarily include variable costs. The legislative history of SB 838 indicates that stakeholders did not focus more specifically on variable cost recovery only because they assumed that the costs were minimal and that they would be fully covered by Pacific Power's Transition Adjustment Mechanism (TAM) and PGE's Annual Update Tariff (AUT). After adding significant RPS resources under SB 838, the Joint Utilities' experience demonstrates that this assumption was incorrect.

Second, the Joint Utilities are not currently recovering all variable RPS compliance costs, despite the fact that such recovery is authorized by statute. While forecasted costs set in rates coupled with a power cost adjustment mechanism (PCAM) could allow the Joint Utilities to recover variable RPS compliance costs, the dead bands, sharing bands, and earnings tests in the Joint Utilities' current PCAMs inhibit this recovery.

Third, the RRTM design is not flawed. As designed, the RRTM determines variable RPS compliance costs by comparing the forecasted value of the energy generated from RPS resources to its actual value. The difference is an actual cost the companies must incur or a benefit that should be returned to customers.

THE RRTM IS CONSISTENT WITH THE RPS

Q. Do you agree with CUB's statement that the RRTM "is not consistent with the RPS, SB 838"?[1]

A. No. Section 13(1) of SB 838, codified at ORS 469A.120(1) plainly states "all prudently incurred costs associated with the compliance with a renewable portfolio standard are recoverable in the rates of an electric company[.]" The language of the statue is clear and unambiguous. While CUB disagrees that SB 838 provides the statutory support for the proposed RRTM, CUB ultimately concedes that the Commission has the authority to adopt the RRTM for policy purposes.[2]

[1] UM 1662/CUB/100, Jenks-Hanhan/3.
[2] *Id.* at 6.

Q. What is the Renewable Adjustment Clause (RAC)?

A. Section 13(3) of SB 838 provides for an automatic adjustment clause to allow utilities timely recovery of costs to "construct or otherwise acquire" renewable resources and for associated transmission. To facilitate the recovery of these costs, the Commission established the RAC.

Q. How does the RAC affect the proposed RRTM?

A. The existence of the RAC has no direct bearing on the availability of an additional mechanism, such as the RRTM for recovery of variable costs or return of variable benefits. The statute is silent as to a recovery mechanism for all other costs of compliance, and does not exclude those other costs from recovery, or preclude the Commission from establishing a necessary mechanism for utilities to recover all variable RPS compliance costs.

Q. Do you agree with CUB's position that costs not covered under the RAC "can only enter rates either through currently existing automatic adjustment clauses or through a general rate case?"[3]

A. No. CUB's statement is not supported by a plain reading of the statute or the legislative intent of SB 838. The statute plainly authorizes recovery of "all" prudently incurred costs of compliance with the RPS and contains no express limitation on the recovery mechanisms available for recovery of "all" RPS compliance costs. If the legislature intended for recovery of costs outside the RAC to be restricted to only currently existing adjustment clauses or general rates cases, it could have easily included such a restriction in SB 838 or amended the statute in one

[3] *Id.*

of the many legislative sessions since SB 838 was enacted. To read such a restriction on cost recovery into SB 838 expands the language of SB 838 beyond its normal and reasonable meaning and is inappropriate. Furthermore, the source CUB uses as the basis for their position is an undated memorandum authored *by CUB.* CUB's memorandum is not a part of the legislative record of SB 838 testimony and exhibits maintained by the Secretary of State. Without evidence that the legislature was aware of and considered CUB's memorandum, it is not appropriate to rely on CUB's memorandum to determine the legislature's intent.

Q. Does the actual legislative history of SB 838 provide insight on how parties viewed cost recovery for the variable costs of RPS resources?

A. Yes. According to the legislative history of SB 838, stakeholders did not recognize the magnitude of the potential variable costs or the inadequacy of utilities' current variable costs recovery mechanisms. Instead, stakeholders focused on avoiding regulatory lag for fixed cost recovery and did not specifically address cost recovery mechanisms for the variable costs of RPS. The 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 recover those variable costs.

For example, in its written testimony, 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."[4] Similarly, 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."[5]

Only after SB 838 was enacted and the Joint Utilities added significant new RPS resources did it become clear that there are large variable costs associated with shortfalls in forecast renewable generation and changes in market prices used to value the variable benefits of renewable energy. These are the costs which the RRTM now seeks to capture in accordance with SB 838's cost-recovery policy.

Q. Are RPS resources actually modeled as "free energy" in prices?

A. No. 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.

[4] Senate Environmental and Natural Resources Committee, March 15, 2007 Public Hearing, Measure SB 838, Exhibit D, Jason Eisdorfer, Citizens' Utility Board of Oregon at 1. CUB's testimony in this case confirms that stakeholders shared an oversimplified understanding of variable costs and benefits associated with RPS compliance. *See also* UM 1662/CUB/100, Jenks-Hanhan/13 (*citing* Exhibit CUB/104).
[5] 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.

Q. In their reply testimonies, all parties expressed concern regarding a shift in risk from the Joint Utilities to customers as a reason the Commission should reject the RRTM. How do you respond?

A. By authorizing recovery of all prudently incurred costs of RPS compliance, the legislature made the choice to require customers to bear the costs of SB 838 compliance. The RRTM is consistent with SB 838's assignment of compliance cost risk to customers.

Q. Do you agree with ICNU's position that the RRTM is not necessary because the variability of renewable resources has not significantly affected net power costs (NPC)?

A. No. The degree of variability of RPS resources is not a qualifier for the recoverability of variable RPS compliance costs. SB 838 clearly states that *all* costs associated with RPS compliance are recoverable. There is no mention of a variability test nor is one implied.

Q. Do you agree that the Commission has already issued orders in previous proceedings that are contrary to the Joint Utilities' position in this proceeding?

A. No. In docket UE 246, PacifiCorp cited SB 838 as a justification for a PCAM without dead bands, sharing bands, and an earnings test, an argument that the Commission rejected. The Commission did not, however, "implicitly determine that the PCAM was consistent with the SB 838 recoverability requirements."[6] In fact, the Commission explicitly "acknowledge[d] that ORS 469A.120(1) provides for recovery

[6] UM 1662/ICNU/100, Mullins/6.

of prudently incurred SB 838 compliance costs"[7] but found that a full PCAM was not the appropriate method to recover variable RPS compliance costs as they were a slice of total NPC.

PGE also proposed a mechanism similar to the RRTM in docket UE 283 that would have allowed for the recovery of variable RPS compliance costs. This proposal was withdrawn as part of a settlement agreement, however, and to suggest the proposal was withdrawn for any reason other than to facilitate a settlement is incorrect.

CUB and ICNU also cite docket UE 165 where PGE proposed a hydro-only PCAM and the Commission rejected it because it did not fit the Commission criteria for a well-structured PCAM. This docket is from 2004—well before SB 838 became law—and has no bearing on this proceeding.

ICNU also references Pacific Power's renewable resources recovery proposal in Docket UE-140762 before the Washington Utilities and Transportation Commission (WUTC). Similar to the Commission's rationale in docket UE 246, the WUTC declined to adopt a narrowly tailored tracking mechanism justified by the Washington's RPS, choosing instead to adopt a PCAM which had not previously been in place for PacifiCorp in Washington.

[7] *Re PacifiCorp, dba Pac. Power, Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 at 14 (Dec. 20, 2012).

CURRENT RECOVERY OF VARIABLE RPS COMPLIANCE COSTS

Q. Are the Joint Utilities adequately recovering their variable RPS compliance costs in current rates?

A. No. The Joint Utilities have shown that there are consistent variances between the variable RPS compliance costs used to set rates and the actual variable costs of RPS compliance. Under the Joint Utilities' PCAMs, the Joint Utilities are currently allowed to recover only a fraction of these costs, if any.

Q. Would improving the NPC forecast result in recovery of all variable RPS compliance costs?

A. Not necessarily. It is easy to suggest that an improved forecast would be the "fix all" for the under recovery of variable RPS compliance costs. But no forecast will ever be perfect, particularly with respect to intermittent RPS resources. The RRTM provides the best, most accurate mechanism to true-up the variable RPS compliance costs, which allows for all RPS compliance costs to be recoverable.

Q. Staff, CUB and ICNU contend that the PCAM provides an adequate vehicle to recover variable costs associated with RPS compliance. Do you agree?

A. No. The PCAMs of the Joint Utilities were constructed with dead bands, sharing bands, and earnings tests. The current PCAMs were established to be "limited to unusual events and capture power cost variances that exceed those considered normal business risk for the utility."[8] The PCAMs cannot serve as both an insurance policy to capture only extraordinary swings in NPC and as a mechanism to recover *all* prudently incurred costs associated with RPS compliance. Additionally, SB 838

[8] *Id.* at 13.

provides that all RPS compliance costs are recoverable, not just the extraordinary variances of such costs.

Q. ICNU contends that the RRTM should be designed consistently with the Commission's criteria for a properly designed PCAM. Is this assertion correct?

A. No. The Commission intended that a PCAM would apply to all variable power costs, rather than a subset of those costs. The purpose of the RRTM is to allow recovery for a discrete subset of variable costs—the RPS compliance costs authorized for recovery by statute—and it should not be subject to the same considerations as a PCAM that applies to a wider range of power costs. In this way, the RRTM is similar to the Commission's treatment of sales of renewable energy credits, where 100 percent of actual revenues are credited to customers. [9]

Q. Is it appropriate to consider utility earnings when determining whether the Joint Utilities' variable costs associated with RPS compliance are recoverable?

A. No. CUB states that "if earnings are within this reasonable range, the utility is considered to be fully recovering its costs and earning a reasonable return."[10] But this is not the way the Commission sets rates. In a general rate case, the Commission approves a very specific return on equity (ROE) and very specific costs, which are then used to design rates. The Commission does not approve a range of costs. Comparing the costs used to set rates to actual costs is the only accurate and

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[9] *See, e.g., In the Matter of PacifiCorp, dba Pacific Power Application Requesting Approval of Sale of Renewable Energy Credits*, Order No. 10-210, Docket No. UP 260 (June 9, 2010) (The Commission adopted Staff's recommendation to authorize PacifiCorp to sell renewable energy credits not eligible for compliance with the Oregon Renewable Portfolio Standard and record the net proceeds in a balancing account for return to customers.).
[10] UM 1662/CUB/100, Jenks-Hanhan/7.

appropriate measurement to determine variable RPS compliance costs and whether those costs have been recovered.

RRTM DESIGN

Q. All parties refer to the use of market prices in the RRTM as a justification for the Commission to reject the RRTM. How do you respond?

A. The market value of the generation from RPS resources is the best metric of the economic benefit customers receive from RPS resources, and the RRTM design is a transparent measure of the fluctuations in that benefit over time. NPC rates are set using a forecast of NPC in Pacific Power's TAM and PGE's AUT. As discussed above, the forecast includes an economic benefit to customers for RPS resources. The zero fuel cost generation of the RPS resources lowers NPC by avoiding purchased power and fuel costs and/or making wholesale sales. This benefit is forecasted and included in the TAM or AUT. Actual NPC also includes an economic benefit to customers, based on the actual output from the RPS resources and the actual market conditions. The difference between the forecast and the actual benefit is a measurement of the additional costs incurred, or benefits realized, by the Joint Utilities due to RPS compliance. Under SB 838, when the variance results in an additional cost it should be recovered from customers, and when the variance results in an additional benefit to customers it should be returned.

Market price is essential to the calculation of both the forecasted and the actual cost or benefit of RPS resources that is passed on to customers. The RRTM does not seek to true-up just the generation of RPS resources because the generation alone does not account for the variable RPS compliance costs and would de-link the

RRTM from the Joint Utilities actual NPC. The Joint Utilities have proposed using hourly market prices because they are verifiable and are published by an independent third-party. 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.

Q. Please explain why the value of the energy from RPS resources is a key component of determining variable RPS compliance costs.

A. Variable RPS compliance costs cannot be determined without valuing the energy generated by RPS resources. In the RRTM, market price is used to determine the value or the benefit of the RPS generation. Assume in a given hour the Joint Utilities forecast 100 MWh of RPS generation and a market price of $25 per MWh. This amounts to a benefit of $2,500 embedded in the forecasted NPC, by either eliminating 100 MWh of market purchases, selling the 100 MWh at market, or some combination of the two.

The same logic is used to determine the benefit from RPS generation in actual NPC. Assume that in the same hour as above actual RPS generation equals 50 MWh and the actual market price is $30 per MWh. This would equal a realized benefit of $1,500 embedded in actual NPC. Without the RRTM, the Joint Utilities will collect a lower amount of NPC than actually incurred because of the existence of RPS generation.

Q. Is there a possibility that the RRTM could result in the Company recovering costs in excess of actual NPC?

A. Yes, but this would be a rare occurrence. To address this situation, the Joint Utilities propose capping the RRTM to preclude recovery or refund of costs above or below actual NPC.

Q. Is PowerDex an acceptable source for hourly market prices?

A. Yes. Using actual market prices from PowerDex makes sense as it is an independent party and the information is verifiable and reliable. As CUB pointed out, the market prices are proprietary information, and the Joint Utilities must facilitate the parties' review in this and future RRTM proceedings. Indeed, the Joint Utilities have acquired permission from PowerDex to provide the hourly prices to parties as highly confidential information, which should address the access concern raised by CUB.

Q. How do you respond to ICNU's concern that including market prices in the RRTM calculation causes the RRTM to have an inverse relationship with NPC?

A. The Joint Utilities disagree with ICNU's generalization as it is based on the incorrect assumption that NPC always moves the same direction as market prices and the RRTM will move the opposite direction. The RRTM does not always move inversely to market price variance, i.e., a decrease in market prices does not always result in an increased RRTM deferral. The RPS generation variance must also be taken into account. Additionally, NPC does not always move the same direction as market prices, i.e., decreases in market prices do not always result in lower NPC. It is true that market purchases may decrease, thus lowering NPC, but revenue from market sales may also decrease, increasing NPC. Table 1 below shows an example where market price decreases and the RRTM result is a refund to customers.

Table 1
Market Price Impact on RRTM

	Forecast	Actual	Delta/Deferral
RPS Generation (MWh)	100	150	50
Market Price ($/MWh)	$ 35	$ 30	$ (5)
RPS Market Value	$ 3,500	$ 4,500	$ 1,000

Renewable resources are one reason NPC does not always move in the same direction as market prices. Market prices are often impacted by the energy produced by renewable resources in a given region. This is especially true at the Mid-Columbia market, where when the wind is blowing it is blowing for most wind resources in the market. During these times, the Joint Utilities still must maintain base load and reserves and integrate the energy from the wind by using dispatchable resources. This can impede the Joint Utilities from taking advantage of the low market prices and may even cause them to sell at the lower than normal prices.

Q. Would there be unintended consequences if market prices are excluded from the RRTM calculation?

A. Yes. If market prices are excluded from the RRTM calculation, the comparison of forecast and actual RPS resources would no longer represent the impact on NPC and would be subject to illogical outcomes. For example, in 2008 PacifiCorp's actual NPC were approximately $33.8 million higher than forecast on an Oregon-allocated basis. However, in 2008 actual RPS wind generation exceeded forecast by 30 GWh. If the RRTM were calculated without consideration of the change in market prices (i.e. if the calculation applied forecast market prices to the forecast and actual wind generation) it would have resulted in a refund to customers of approximately $0.7 million after accounting for purchase power agreement (PPA) costs.

Q. Is CUB correct that "renewables can be thought of as a fixed price hedge"?[11]

A. No. The Joint Utilities use hedging to mitigate price risk. A power or natural gas hedge must provide three components to be effective: 1) a predetermined quantity, 2) a predetermined time the product will be received, and 3) a predetermined price. RPS resources provide only a predetermined price. Additionally, RPS resources are not without risk as their output is difficult to predict and their generation output is largely out of the Joint Utilities' control.

Q. Does the use of market prices in the RRTM inappropriately subject RPS resources to fuel cost risk?

A. No. This is because the value of the generation of RPS resources, the decreased purchased power and fuel costs and/or the wholesale sales made at market, is determined at the time the RPS resource is generating. Market prices depend on the supply and demand for electricity, and are influenced by factors in addition to fuel costs, including wind and other weather conditions. Because RPS resources are not hedges, as they do not provide a predetermined quantity at known times, their generation value is subject to hourly price fluctuations which are impacted by fuel costs. Additionally, natural gas plants must be used to provide reserves and integrate RPS resource generation, causing the natural gas plant to be ramped up and backed down.

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[11] *Id.* at 13.

Q. Do the Joint Utilities have processes in place to monitor wind and other weather conditions, update forecasts, and make system changes as needed?

A. Yes. However, the difficulty of forecasting wind accurately more than a few days in advance makes its value subject to short term markets.

Q. CUB contends that the RRTM would be double counting the wind day-ahead forecast error costs included in PGE's AUT. Do you agree?

A. No. While PGE does include a cost of wind day-ahead forecast error in its NVPC forecast, it is not in the RRTM. The cost of wind day-ahead forecast error estimates 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.

The RRTM does not include the costs related to changes in PGE's non-wind resource portfolio and market position that result from the difference between the day-ahead and the hour-ahead forecasts. Rather, the RRTM is aimed largely at the value of annual energy variance (i.e., the variance between forecast annual wind energy market value and actual annual wind energy market value).

Q. Does the RRTM ignore the diversity benefits RPS resources provide to the Joint Utilities' systems?

A. No. As explained above, the AUT and the TAM both include benefits of RPS resources in the form of reduced purchased power and fuel costs. Actual NPC includes these same benefits. However, there are also variable costs associated with the generation of the RPS resource, which has also been explained in this rebuttal testimony and in the Joint Utilities' direct testimony. The RRTM simply trues-up both the benefits and costs between the forecast and actuals.

ICNU uses an analogy of a diverse stock portfolio and disagrees that a single resource group or stock should be carved out without regard to the overall performance of the entire portfolio. This analogy does not accurately compare to the RRTM as the RPS requires the Joint Utilities to have RPS compliant resources on its systems. The Joint Utilities adhere to principles of least-cost and least-risk in developing their anticipated resource needs; however, the RPS adds another dimension to the Joint Utilities' resource portfolios which may not be pursued absent the RPS.

Q. How do you respond to ICNU's argument that a true up of production tax credits (PTCs) could harm customers?

A. To exclude the true up of PTCs as part of the RRTM would go against the language of SB 838. PTCs are an easily quantifiable, direct benefit of RPS compliant resources, so to the extent that actual PTCs are less than forecasted, the company incurs an additional cost. While PTCs that cannot be claimed in a given year can serve to reduce Accumulated Deferred Income Taxes (ADIT), the impact on revenue requirement is small. ADIT is reflected on the balance sheet, while PTCs are reflected on the income statement, so for revenue requirement purposes, there is approximately a 90/10 relationship between the two. In other words, for a variance of $1 million in PTCs, one would expect a variance of $0.1 million in revenue requirement associated with ADIT.

Q. Do you agree with Staff that the RRTM inherently assumes that "the load forecast is correct and that [u]nrealized [e]nergy is always needed"?[12]

A. No. The RRTM does not seek to true-up just the RPS resource generation but rather the cost associated with this generation. The impact on NPC related to RPS resources occurs whether or not the load forecast is accurate. Additionally, trying to account for the load variance in the RRTM treats the RPS resources like dispatchable units which can be ramped up and down as needed. Because RPS resources are not dispatchable, load and RPS generation are independent of each other.

Staff's testimony included the following scenario; actual load is 100 MWh less than the load forecast, and the NPC forecast included 150 MWh of wind but in actual NPC there was no wind. Removing the load forecast variance would mean that the value of only 50 MWh of wind would be subject to the RRTM because the other 100 MWh was not needed in actuals. In this example and all other variables being equal, the 150 MWh of wind generation would reduce the NPC forecast by reducing purchased power and/or fuel costs. Had the 150 MWh of wind generation occurred in actuals, it would have also reduced actual NPC; 50 MWh of wind would have replaced purchased power and/or fuel cost and the other 100 MWh of wind could have been sold at market or further reduced purchased power and/or fuel costs.

The difference in the value of RPS generation in forecasted and actual NPC is an actual cost associated with RPS compliance on which the load variance has no bearing. Limiting the RRTM by removing the load forecast variance would not allow for all RPS compliance costs to be recovered or additional benefits to be refunded.

[12] UM 1662/Staff/100, Crider/10.

Q. Staff recommends using the NPC models to determine the variable RPS compliance costs if the Commission adopts an RRTM. Would Staff's recommendation be an improvement to the RRTM?

A. No. Staff's suggestion is to compare the base model run to a second run that uses the actual RPS resource generation. This approach would not produce the actual RPS variable costs incurred; rather, the second model run would merely result in a forecasted NPC study with actual RPS generation. To accurately capture the variable RPS compliance cost, the second run would also need to include actual market prices to determine the negative cost associated with RPS generation. The analysis could be further refined to include actual market purchases and sales, actual thermal plant operation, and so on; essentially becoming the actual NPC.

Q. Alternatively, Staff recommends several modifications to the RRTM design intended to eliminate different risk elements. Do you agree with Staff's proposed changes?

A. No. Staff's alternative formula would not result in recovery of variable RPS compliance costs. Staff first proposes to remove 'market risk' from the RRTM by applying the forecasted market price to both the forecast and actual RPS generation. Staff's proposal is ineffective because the realized benefit of actual RPS generation cannot be accurately determined using forecasted prices. Freezing the valuing factor of the RPS generation does not compare forecasted costs to actual cost, but the forecast value of forecast RPS generation to a forecasted value of actual generation. Furthermore, if the forecasted market price is greater than the actual market price the result is an increased deferral/refund when compared to using actual market price.

Confusingly, Staff later recommends that actual transaction costs be used in place of the PowerDex market prices. It is not clear if this recommendation supersedes Staff's proposal to only use forecasted market prices in the RRTM calculation. The RRTM could use actual transactions in lieu of published market prices (i.e., PowerDex) to value RPS generation but this would add complexity without adding equivalent value.

Staff also proposes to remove 'forecast risk' from the RRTM by netting changes in RPS generation against changes in load. As described above, including load variances from the RRTM misrepresents the cost impact of RPS generation.

Q. Has any party proposed an acceptable alternative or modifications to the RRTM?

A. No. Both of Staff's proposed alternatives appear to limit the RRTM calculation to changes in RPS generation volume, without consideration of the cost impact that flows through actual NPC. Staff's modifications to the RRTM calculation would be ineffective because they distort the value of the RPS benefit embedded in NPC and could result in inaccurate and illogical deferrals or refunds. Staff's proposals are silent on accounting for the cost variances of PPAs; regardless of the RRTM method it is important that PPA variances are included.

Q. What is the Joint Utilities recommendation?

A. The Joint Utilities recommend that the RRTM be adopted as described in our direct and rebuttal testimony. The RRTM accurately and transparently tracks the variable costs associated with RPS compliance and is the best mechanism to allow the Joint Utilities to recover those costs as is required in SB 838.

Q. Does this conclude your joint rebuttal testimony?

A. Yes.