Davison Van Cleve PC
Attorneys at Law
TEL (503) 241-7242 ● FAX (503) 241-8160 ● jog@dvclaw.com
Suite 450
1750 SW Harbor Way
Portland, OR 97201

September 14, 2018

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem OR 97301

Re: In the Matter of OREGON PUBLIC UTILITY COMMISSION,
Rulemaking Related to Renewable Portfolio Standard
Docket No. AR 610

Dear Filing Center:

Please find enclosed the Comments of the Alliance of Western Energy Consumers in the above-referenced docket.

Thank you for your attention to this matter. If you have any questions, please do not hesitate to call.

Sincerely,

/s/ Jesse O. Gorsuch
Jesse O. Gorsuch

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

AR 610

In the Matter of	)	
	)	COMMENTS OF THE ALLIANCE OF
Rulemaking Regarding the Incremental	)	WESTERN ENERGY CONSUMERS
Cost of Renewable Portfolio Standard	)	
Compliance.	)	
	)	

I. INTRODUCTION

Pursuant to the Oregon Public Utility Commission Staff's ("Staff") August 15, 2018 Memorandum in the above-referenced docket, the Alliance of Western Energy Consumers ("AWEC") submits these comments in response to the questions posed in Staff's Memorandum. These comments were prepared with the assistance of Bradley G. Mullins.

II. COMMENTS

AWEC's responses to Staff's questions are guided by the premise that the fundamental purpose of identifying the incremental cost of compliance with Oregon's renewable portfolio standard ("RPS") is to protect customers from paying rates that exceed the 4% cost cap provided in ORS 469A.100. As discussed below, the current methodology, which calculates the incremental cost of compliance based on the cost of renewable energy certificates ("RECs") retired in a compliance year, does not serve this purpose and should be revised. With this principle in mind, AWEC provides the following responses to Staff's questions:

A. Incremental Cost of Compliance:

1. <u>Is the proxy plant methodology, last examined in Order No. 14-034 in Docket No. UM 1616, and summarily defined in OAR 860-083-0010(30), accurately and appropriately serving as the baseline for the incremental cost of compliance calculation?</u>

At this time, AWEC does not have concerns with the current proxy plant methodology, but will review other parties' proposals on this issue. AWEC does note that the rules currently do not reflect the stipulation approved in Order No. 14-034 which, in addition to a combined cycle plant, uses a simple cycle combustion turbine ("SCCT") to establish capacity

DAVISON VAN CLEVE, P.C.
1750 SW Harbor Way, Suite 450
Portland, OR 97201
Telephone: (503) 241-7242

equivalence between the RPS and proxy resources. The rules could be updated to reflect this addition.

2. <u>Do our incremental cost rules accurately reflect the appropriate categories of cost for the incremental cost of compliance calculation?</u>

AWEC would like to see the methodology for calculating firming, shaping, and integration costs clarified and simplified. ORS 469A.100(4)(e) requires the costs to "integrate, firm or shape renewable energy resources on a firm annual basis" to be included in the incremental cost of compliance. OAR 860-083-0100(2)(e), meanwhile, states:

> If an electric company anticipates that it will have firming and shaping services available for sale for a compliance year, the company may not use rates in its Open Access Transmission Tariff ["OATT"] approved by the Federal Energy Regulatory Commission as the basis for the firming or shaping portion of aggregate costs. In such case, the electric company should use the actual or forecasted cost of supplying or purchasing firming and shaping services as the basis for such costs. If an electric company anticipates it will not be able to sell firming and shaping services due to its use of such services, the company may use its approved [OATT] as the basis for such costs.

First, as noted above, AWEC understands that "firming" costs already are incorporated into the proxy plant methodology approved in Order No. 14-034, which uses a SCCT to achieve capacity equivalence between the RPS and proxy resources. Consequently, there would not appear to be a need to separately identify firming costs.

Second, AWEC thinks this rule is confusing and does not lend itself to a transparent accounting of shaping and integration costs. AWEC frankly does not understand what the first part of this rule means and whether it is being used currently by the utilities. It is unclear, for instance, what the "actual or forecasted cost of supplying or purchasing firming and shaping services" is. It is also unclear why or how those costs relate to the sale of such services by the utilities to third parties, and why such a sale would preclude the utilities from using the costs of such services provided in their OATTs.

As AWEC understands, the utilities currently use the costs from their integrated resource plans to identify the costs of shaping and integrating RPS resources for purposes of the incremental cost calculation. The terms "firming, shaping and integrating," however, are inherently vague and do not necessarily correspond to actual services that are commonly provided to an intermittent generator by an energy services supplier. While conceptually AWEC recognizes that these categories represent costs associated with operating renewables, it is difficult to parse out from the utility's portfolio the actual cost of providing those generation services.

DAVISON VAN CLEVE, P.C.
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Viewed in isolation, for example, it may be possible to develop a product to shape the output of a renewable resource to a flat block of power. Determining the actual cost of such services in a diversified portfolio, however, is not straightforward. In a diverse portfolio the variable profile of the renewable resource is combined with the variable output of other resources and loads. The company responds to the net variability from all sources, including the energy imbalance market. The company holds reserves and balances its system to respond to the system variability, but it is not necessary for the utility to individually "shape" the output of each of its renewable resources to independent flat blocks of power.

Given the expansion of markets for wholesale electricity services, such as the EIM, AWEC proposes to simplify the rule to require that the utilities tie the "firming, shaping and integrating" costs as used in the incremental cost calculation to actual services provided through utilities' OATTs, where possible. Rather than developing an artificial construct to determine the cost of shaping and integrating renewables, for example, the incremental cost calculation should just use the generation imbalance charges outlined in Schedule 9 of the utilities' OATTs. Similarly, the reserve costs associated with firming, integrating, and shaping would be assigned based on Schedule 3, Regulation and Frequency Response. PacifiCorp's Schedule 3, for instance, has specified rates for Variable Energy Resources.[1/] This will provide for a far simpler and more transparent calculation of these inputs into the incremental cost of RPS compliance.

3. <u>Are there any additional components of delivered cost that you would specify must be included in the calculation of incremental cost for long-term or short-term resources? What legal and/or policy justification is there for your position?</u>

AWEC has not identified any additional components of delivered cost that should be considered at this time but will review the comments of other stakeholders.

4. <u>Should the cost of qualifying electricity be included in the incremental cost of compliance in the year the electricity is generated, or in the year the associated RECs are retired? What legal and/or policy justification is there for your position?</u>

The cost of qualifying electricity must be included in the incremental cost of compliance in the year the electricity is generated, not when RECs are retired. This is mandated by the plain language of the RPS law and supported by the intent of the 4% incremental cost cap.

[1/] PacifiCorp OATT at 224.

DAVISON VAN CLEVE, P.C.
1750 SW Harbor Way, Suite 450
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The ”paramount goal” of statutory construction is to “discern[] the legislature's intent.”[2/] “In that regard … there is no more persuasive evidence of the intent of the legislature than ‘the words by which the legislature undertook to give expression to its wishes.’”[3/] Thus, “text and context [of a statute] remain primary, and must be given primary weight in the analysis.”[4/] “When the text of a statute is truly capable of having only one meaning” that ends the inquiry,[5/] and the Commission is “without authority to put policy considerations into the meaning of statutes in place of the words that the legislature has chosen to use.”[6/]

ORS 469A.100(4) defines the “incremental cost of compliance” as “the difference between the levelized annual **delivered** cost of the qualifying electricity and the levelized annual **delivered** cost of an equivalent amount of reasonably available electricity that is not qualifying electricity.” For purposes of determining whether a utility has reached the four percent cost cap, the incremental cost of compliance is figured “for the compliance year.” ORS 469A.100(1). Accordingly, the statute requires that the “delivered cost” of qualifying electricity in “the compliance year” be used to calculate the incremental cost of compliance.

Further, while the plain language of the RPS law compels the Commission to calculate the incremental cost in the year the qualifying electricity is delivered, policy considerations also support doing it this way. The purpose of the four percent incremental cost cap is to protect customers from cost increases above this amount relative to the cost customers otherwise would have incurred absent the RPS.[7/] When calculated on the basis of RECs retired in a compliance year, the incremental cost cap does not protect customers from such increases. This is because the utility has already incurred the cost for these RECs and passed that cost through to its customers. Being relieved of the obligation to retire RECs if the 4% cap is reached, therefore, has no impact on customer rates and does not protect customers from incremental cost increases above 4%. Conversely, if a utility is relieved of the obligation to *generate* RECs in a compliance year (by, for instance, not acquiring a new resource that would otherwise be needed for RPS compliance), this would protect customers from cost increases above this cap if properly structured.

2/ State v. Gaines, 346 Or. 160, 171 (2009); ORS 174.020.
3/ Gaines, 346 Or. at 171 (internal citations omitted).
4/ Id.
5/ Id. at 173.
6/ Northwest Natural Gas Co. v. Oregon Public Utility Comm'n, 195 Or. App. 547, 556 (2004).
7/ See Docket No. UM 1783, Comments of the Industrial Customers of Northwest Utilities at 6-7 (July 15, 2016) (identifying relevant legislative history on the intent behind the 4% cost cap).

DAVISON VAN CLEVE, P.C.
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5. <u>Should the rules be amended to reflect any changes you suggested? Do you have any specific recommendations for changes to the rules?</u>

Yes. AWEC has identified the following rules that must be amended to consistently reflect the requirement that the incremental cost be calculated based on the cost of qualifying electricity delivered in the compliance year and has included proposed revisions:

- OAR 860-083-0010(19): "Incremental cost of compliance" ~~means the cost of bundled renewable energy certificates used for compliance for a compliance year~~ has the meaning provided in ORS 469A.100(4), as calculated pursuant to OAR 860-083-0100.
- OAR 860-083-0300(3)(D): If the total cost of compliance exceeds the cost limit under ORS 469A.100, the electric company or electricity service supplier ~~is not required to use additional~~ may bank renewable energy certificates~~ or~~ generated or acquired in the compliance year that exceed the cost limit and is not required to make an alternative compliance payment to meet the applicable standard or generate or acquire additional renewable energy certificates in future compliance years to the extent doing so will result in the electric company or electricity service supplier exceeding the cost limit.

B. <u>Four Percent Cost Cap:</u>

6. <u>What should happen when an electric company reaches the four percent cost limit? What legal and/or policy justification is there for your position?</u>

Two things should happen when an electric company reaches the cost limit. First, it should not be required to retire RECs for compliance above the cost limit. Compliance with the RPS is evidenced by retiring RECs, and such compliance is not required to the extent the utility has exceeded the cost cap. Second, the utility should not be required to acquire new RPS-qualifying generation or RECs. Under the existing framework, an electric company would not retire RECs above the 4% cost limit, but this limit would be determined entirely by the cost of the RECs retired, meaning that the electric company could be generating RECs at a cost well above the 4% cost limit, and planning to acquire more RECs to comply with the RPS in the future, because the cost limit is unrelated to the cost of RECs delivered in the compliance year.

Under the statutorily required construct, the cost of RECs delivered (not retired) in the compliance year would inform whether the utility exceeded the 4% cost cap. If it did, then the utility could bank any RECs that exceed the 4% cost cap. Importantly, under this formulation, the cost of RECs is determined when they *enter* the bank, rather than when they are pulled from it for compliance. Thus, while a utility may use banked RECs for compliance, the cost of RECs identified for incremental cost calculation purposes would only be those that were

DAVISON VAN CLEVE, P.C.
1750 SW Harbor Way, Suite 450
Portland, OR 97201
Telephone: (503) 241-7242

generated (or acquired) in the compliance year. The example below illustrates how the different approaches can yield different results for customers.

Revenue Requirement	Load (MWh)	Number of RECs Retired	Number of RECs generated	Incremental Cost per REC
$ 1,333,333.33	20,000	4,000	6,000	$ 10.00

First, assume the RPS is 20%. In this example, if the incremental cost were figured based on RECs retired, the incremental cost would be $40,000 (4,000 RECs retired multiplied by $10/REC). That equates to a 3% incremental cost of compliance and the cost cap is not reached. Conversely, if the incremental cost is figured based on RECs generated in the compliance year, the incremental cost would be $60,000 (6,000 RECs generated multiplied by $10/REC). That equates to a 5% incremental cost of compliance. In this circumstance, the utility would still retire 4,000 RECs because that is the amount needed to meet a 20% RPS and is below the incremental cost cap. It would bank the rest.

Alternatively, assume the RPS is 30%. Using the same numbers, the utility would need to retire 6,000 RECs to fully comply. However, because generating 6,000 RECs resulted in it exceeding the cost cap, the utility would only need to retire the amount up to the 4% cap, or 5,333 RECs.

There are two justifications for this approach. First, even though the utility generated more RECs in the compliance year than it needed, it is important to account for all RECs generated that are ultimately held by the utility for RPS compliance because they will eventually be used for compliance purposes and because they represent the true cost to customers of complying with the RPS (any RECs sold to a third party would not be included in the cost of compliance). Second, this approach relieves the utility from acquiring new above-market resources for RPS compliance because it has exceeded the incremental cost cap. In this way, customers are protected from incurring additional incremental costs for RPS compliance, even though the cost of RECs retired for compliance does not meet the 4% cost cap.

Note that there are other, more complex, variations on the above hypothetical example. A utility may not yet have reached the 4% cost cap on a RECs-generated basis, but forecasts that it will in the near term (i.e., next five years). Alternatively, a utility may be above the cost cap, but forecasts that it will fall below the cap in the near term. Because the RPS law provides only that the utility is not "required" to comply with the RPS if it exceeds the cost cap, AWEC believes these circumstances should be addressed in the IRP process. Essentially, if a utility has not reached the cap, but forecasts that it will, then it must make the least-cost, least-risk resource decision based on the information it has at the time. Regardless of what occurs in practice, the prudence of the utility's decision will be based on what it knew when it made that

DAVISON VAN CLEVE, P.C.
1750 SW Harbor Way, Suite 450
Portland, OR 97201
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decision. The same would be true in the alternative scenario where the utility is above the cost cap but expects to fall below it in the future.

Also note that reaching the cost cap does not necessarily prevent a utility from acquiring RPS-compliant resources, just above-market resources. As PacifiCorp's most recent IRP action plan shows, acquiring a resource for RPS compliance purposes is not the same thing as acquiring an RPS-compliant resource. The utilities may find such resources to be the least-cost, least-risk resources to meet their energy and capacity needs. In such a circumstance, the incremental cost of such a resource is $0, and the cost cap would not preclude the utility from acquiring this resource.

7. <u>What guidance, if any, should our rules provide about the process for when four percent is reached? Do you have any specific recommendations for changes to the rules?</u>

As noted in the response to Question 6, AWEC believes the process for how to proceed when the 4% cost cap is reached should be incorporated into the utility's IRP. The impact of the cost cap is part of the larger resource forecasting process and the utility should make the least-cost, least-risk decision in addressing it.

8. <u>Also considering ORS 469A.075, which requires an implementation plan, what should happen if an electric company is forecast to reach the four percent cost limit in a future compliance year? What legal and/or policy justification is there for your position?</u>

AWEC continues to believe that the RPS implementation plans should be incorporated into the utilities' IRPs. While a legislative change is required to fully incorporate the implementation plans into the IRPs (because the RPS law requires implementation plans to be filed every two years),[8/] the utilities should begin incorporating the forecasting process that occurs in the implementation plans into their IRPs, as the incremental cost cap bears directly on when and whether a utility should acquire a new RPS resource.

9. <u>Should utilities include the cost of unbundled REC purchases at the time of purchase or the time of retirement? What legal and/or policy justification is there for your position?</u>

ORS 469A.100(1) specifies that utilities are not required to comply with the RPS "to the extent that the incremental cost of compliance, *the cost of unbundled renewable energy certificates*, and the cost of alternative compliance payments" exceeds 4% of revenue requirement. Thus, the cost of unbundled RECs must be a consideration in determining whether

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[8/] ORS 469A.075.

DAVISON VAN CLEVE, P.C.
1750 SW Harbor Way, Suite 450
Portland, OR 97201
Telephone: (503) 241-7242

a utility has reached the cost cap. *How* unbundled RECs are considered in this calculation, however, is not specified.

Under the current methodology, unbundled RECs reduce a utility's cost of compliance. That is because, on a RECs-retired basis, unbundled RECs retired for compliance take the place of more expensive bundled RECs. Unless the utility is acting imprudently, unbundled RECs should always be cheaper than bundled RECs because if they were not then the utility would simply use bundled RECs and avoid purchasing unbundled RECs. Additionally, bundled RECs include both energy and environmental attributes, whereas unbundled RECs represent only the environmental attributes. Consequently, the more unbundled RECs utilities use, the lower their cost of RPS compliance. This is demonstrable in the fact that 20% (the maximum amount) of both PGE's and PacifiCorp's compliance obligations have come from unbundled RECs.

AWEC believes unbundled RECs should continue to reduce a utility's cost of RPS compliance. Otherwise, utilities would be disincentivized from making the least-cost RPS compliance decisions for their customers. Assuming the Commission modifies the current methodology to calculate the cost of compliance on a RECs-generated basis rather than a RECs-retired basis, however, incorporating the cost of unbundled RECs must change. AWEC does not have a strong preference over how this would be accomplished, and is open to recommendations on this issue.

One idea would be to keep the same construct as is currently used, but on a RECs-delivered basis. Thus, currently, unbundled RECs essentially supplant bundled RECs for compliance purposes. When a utility purchases unbundled RECs to meet 20% of its compliance obligation, this means it does not need to use bundled RECs for this portion and can keep those in the bank. Similarly, going forward, if a utility purchases, for instance, 500,000 unbundled RECs at $1 per REC, then these unbundled RECs would supplant 500,000 bundled RECs the utility generated in the compliance year. If the cost of bundled RECs was $10 per REC, then purchasing the unbundled RECs would reduce the utility's cost of compliance by $4.5 million ($5 million for 500,000 bundled RECs at $10/REC minus $500,000 paid for unbundled RECs). The supplanted bundled RECs would then go into the bank for future use. This methodology reflects how unbundled RECs impact the cost of compliance today, but adapted for a RECs-delivered methodology.

If this methodology is adopted, AWEC also recommends that unbundled RECs figure into the calculation of the cost of RPS compliance when they are used rather than when they are purchased. AWEC recognizes that this treats unbundled RECs differently than bundled RECs under AWEC's proposal. There are two rationales for this.

First, the RPS law allows for this treatment. While the "incremental cost of compliance" must be calculated based on the "delivered cost of the qualifying electricity" in the compliance year, unbundled RECs are not a component of the "incremental cost of compliance.

DAVISON VAN CLEVE, P.C.
1750 SW Harbor Way, Suite 450
Portland, OR 97201
Telephone: (503) 241-7242

Rather, a determination of whether a utility has reached the 4% cost cap is the result of combining the incremental cost of compliance, the cost of unbundled RECs, and the cost of alternative compliance payments. Thus, unbundled RECs may be treated differently than bundled RECs when determining the cost of RPS compliance.

Second, calculating the cost of unbundled RECs when used rather than when purchased allows for a smoother and more predictable incremental cost forecast. For instance, a utility could purchase five years' worth of unbundled RECs in a single year, which might bring it below the 4% cost cap for that year if they were all counted, but bring it above the 4% cap in subsequent years. Counting unbundled RECs when retired avoids this "lumpiness" problem.

C. Other Category of Question:

10. Are there any specific changes you would like to see to the administrative rules regarding any aspect of the ORS 469A.100 cost limit calculation? What legal and/or policy justification is there for your position?

At this time, AWEC has not identified specific changes to the incremental cost rules other than those discussed above. AWEC reserves it right, however, to respond to other stakeholders' responses to this question.

Dated this 14th day of September, 2018.

Respectfully submitted,

DAVISON VAN CLEVE, P.C.

<u>/s/ Tyler C. Pepple</u>
Tyler C. Pepple
1750 SW Harbor Way, Suite 450
Portland, Oregon 97201
(503) 241-7242 (phone)
(503) 241-8160 (facsimile)
tcp@dvclaw.com
Of Attorneys for the
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