BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 610

In the Matter of	
	)
Rulemaking Regarding the	)
Incremental Cost of Renewable	)
Portfolio Standard Compliance.	)
	)

COMMENTS OF THE

OREGON CITIZENS' UTILITY BOARD

April 10, 2020

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 610

In the Matter of		
	)	
Rulemaking Regarding the	)	RESPONSE TO STAFF'S REQUEST
Incremental Cost of Renewable	)	FOR COMMENTS FROM THE
Portfolio Standard Compliance.	)	OREGON CITIZENS' UTILITY BOAR
	)	

I. INTRODUCTION

Pursuant to the Oregon Public Utility Commission Staff's ("Staff") March 27, 2020 Memorandum in the above-captioned proceeding, the Oregon Citizens' Utility Board ("CUB") submits these comments in response to Staff's request. It was 19 months ago when CUB last commented in this proceeding. CUB's primary concern at the time was that Oregon's Renewable Portfolio Standard ("RPS") statute provided constraints on implementing the cost cap which prevented a more reasonable approach to identifying the actual incremental costs of RPS compliance. Much of this was caused by the overly prescriptive language in 2007's SB 838—the original RPS bill—combined with the changes in the electric industry since 2007.

CUB has been through additional Integrated Resource Plan ("IRP") cycles since those 2018 comments and believes that this problem is getting worse. Today's IRPs center on the need to add capacity to meet peak loads as coal generation declines. In IRPs, renewable projects that are combined with storage are increasingly the preferred resource. This makes sense. Including storage in a renewable project allows a utility to shift the energy into the early evening hours when capacity is most valuable, bringing an added capacity benefit to the system. However, if the focus of the IRP was solely meeting the RPS requirements, then renewable projects would never include storage. This is because the RPS is energy based, and utility procurement is capacity focused. Storage increases the capacity value of renewables, but does not increase the energy produced. If a utility was planning for the least-cost path to RPS compliance then it would never include projects that combine storage with renewables. While it might be tempting to remove the capital investment associated with the storage component, this is problematic. A utility might find that a stand-alone wind project was the least cost resource to meet RPS obligations, but that solar with storage was the least cost resource to meet the capacity needs of customers, independently of the RPS. Removing the storage component from the solar project would not reflect the least cost path to meeting the RPS, because the utility would not have built a stand-alone solar facility to meet the RPS requirements. In reality once the utility planned to meet its customers' capacity needs, it no longer needed the wind facility. Because it appears that the utility would have built the renewable project even without an RPS mandate, it suggests that the incremental cost of compliance from the solar and storage project is zero.

PacifiCorp's recent IRP showed renewables to be the least cost resource across all six states without considering the impact of the RPS requirements of Oregon. It did not demonstrate any incremental cost of renewables. From a logic standpoint, if an IRP shows that renewables are the least cost, least risk resource for states that do not have an RPS, then those same renewables are least cost, least risk for Oregon and are not imposing incremental costs on Oregon customers. A reasonable approach to identifying the incremental cost of compliance with the RPS would recognize this.

The legal requirement for the incremental cost calculation is codified at ORS 469A.100(4):

> the incremental cost of compliance with a renewable portfolio standard is 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.

How do we interpret this in today's world? In PacifiCorp's case, the IRP is driving investments in renewable resources. Those resources provide qualifying electricity to the Company's Oregon customers (a REC is retired). These same resources also provide non-qualifying electricity to the Company's customers living in states without an RPS (RECs are not retired). What qualifies a resource as "renewable" for RPS compliance in Oregon is that a REC is retired in Oregon, while in states without an RPS, the company can sell the REC. For example, a system-wide renewable resource in PacifiCorp's system would allocate ~26% of the costs and RECs to Oregon. Oregon would retire those RECs for RPS compliance, if needed. Other states, like Utah, without an RPS could sell those RECs to create value for customers.

In today's carbon constrained world, where carbon emissions are an economic risk, utilities build renewable resources to both meet RPS requirements and to meet load/resource balance outside of RPS requirements. The only difference is whether the REC is retired or sold. This suggests that we are now at a point where the difference between the cost of the qualifying and non-qualifying resources is the value of the REC.

CUB will now address the questions that Staff laid out for stakeholders consideration in its March 27, 2020 memorandum.

II. STAFF QUESTIONS FOR STAKEHOLDERS

1) Are there any additional options for calculating incremental cost that Staff should consider? What legal or policy reasons support your position?

At this time, CUB is not proposing further options for consideration.

2) ***Should AR 610 include rules or standards for assessing REC bank management? What legal or policy reasons support your position?***

SB 838 required first in/first out management of the REC bank. This requirement was removed in SB 1547 as part of the negotiation that created the expanded RPS. CUB believes that it would be inappropriate to reinstate this requirement through rulemaking.

However, CUB believes that REC banks should be managed prudently and there should be a forum to discuss REC bank management. Because the management of the REC bank will change as the increases in the RPS become steeper, CUB is doubtful that rulemaking is the right forum for this discussion. As we saw from the overly prescriptive requirements contained in SB 838, setting rules for an uncertain future can lead to results that must be later revisited. CUB has been supportive of folding the Renewable Portfolio Implementation Plan (RPIP) into the utility's IRP and this may be an appropriate place for a review of REC bank management.

3) ***Are there any RECs that should not be included in the compliance calculation? If so, please identify these and explain why.***

Oregon is in a different world than when the RPS was passed. Utility IRPs are recommending renewable investments (sometimes with storage) to meet the needs of the system without regard to the RPS requirements. RECs generated from renewable projects that were developed as least cost/least risk resources without regards to RPS requirements do not have an incremental cost of compliance beyond the value of the REC. Whether these RECs are included in the calculation depends on whether the calculation recognizes their true incremental cost.

In addition, the compliance calculation reflects the cost of qualifying electricity and qualifying electricity requires RECs to be retired. The levelized cost of electricity from renewable projects where the RECs are sold is not qualifying electricity and does not enter in the compliance calculation.

Assume REC costs are included in the incremental and total cost calculations in the year of generation.

4) ***Is this appropriate? Is it feasible?***

CUB discussed this in earlier comments. CUB does not believe that this is appropriate. The cost calculation relates to qualifying electricity and this requires RECs to be retired. Therefore, the cost calculation relates to the year of the retirement, not the generation.

5) ***Are there alternatives that are also feasible and/or more appropriate? If not, why not?***

CUB believes the best method is for the cost calculation requirement to focus on the levelized cost of the electricity that is used to comply which the RPS at the time that RECs are retired. It is at the point of retirement that the electricity qualifies for the RPS.

6) What should happen to the existing bank of RECs once the new method of calculating cost is implemented? Should RECs being retired from the existing REC bank be accounted for in the total cost and/or incremental cost calculation? If so, how? If not, why?

CUB does not agree that applying the cost calculation in the year of generation meets the RPS requirements. We are not recommending this “new method”.

Assume that REC Sales are subtracted from the total cost of compliance.

7) Is this appropriate? Is it feasible?

The levelized cost of renewable electricity that produces RECs that are sold is not a cost associated with qualifying electricity, so it must be subtracted from the cost of compliance. When the REC is sold, the electricity associated with it, no longer qualifies for the RPS, so the cost of generating that electricity is no longer a compliance cost. However, the levelized cost of electricity (the cost of producing the REC) is not the same as the revenue from the REC sales. (see #8 below).

8) Are there alternatives that are also feasible and/or more appropriate? If not, why not?

The levelized cost of the electricity associated with generating RECs that are sold (and therefore not used for compliance) should be removed from the compliance calculation as non-qualifying electricity. This is not the same thing as the revenue from REC sales – though the REC sale would reduce the levelized cost of this electricity. The RPS requirement is to use the levelized cost of qualifying electricity in the calculation.

Dated this 10th day of April 2020.

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