MEMO

To: CETA Stakeholders

From: Glenn Blackmon

RE: Informal feedback on compliance issues discussed at Oct. 21 workshop

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Several stakeholders asked at the end of the Oct. 21 workshop that we provide informal feedback on the issues discussed there, with the idea that this would help focus comments to be submitted in November. I'm providing that feedback here, with the understanding that these are not meant as conclusions or final opinions. I look forward to learning more from the written comments, which are requested by Nov. 27, 2019.

1. **Elimination of coal-fired resources by December 31, 2025.** How will a consumer-owned utility demonstrate that it has complied with the requirement in RCW 19.285.030(1) to eliminate coal-fired resources from its allocation of electricity? Should compliance be demonstrated on an annual basis or some other period? How will the demonstration differ if a utility obtains resources includes coal-fired resources in its allocation of electricity to customers of other states? (Is this last question relevant for consumer-owned utilities?)

My sense from the discussion is that a promising approach is for each utility to provide an annual attestation that it did not use coal-fired resources in its allocation of electricity in the prior year. The utility's attestation may require and rely on the attestations of counter-parties who supplied the electricity, including BPA and commercial power marketers.

While there was some discussion of making a forward-looking commitment not to use coal, an after-the-fact certification of compliance seems more consistent with this requirement.

There was a lot of discussion of unspecified electricity and what should be done if a utility purchases electricity that is later discovered to be from a coal-fired generating plant. A related comment was that resolution of the no-coal compliance issue should wait until the Section 13 markets workgroup had completed its work. It seems to me that this overstates the connection, if any, between coal-fired resources and the treatment of unspecified sources.

Here's why: "Coal-fired resources" is defined to exclude electricity purchases "for which the source of power is not known at the time of entry into the transaction," as long as the transaction is for less than a month. This phrase uses different words but says that unspecified electricity is not considered a coal-fired resource. There will not be an attribution of coal to unspecified sources, akin to the net system mix that we used until this year for fuel mix disclosure.

There could nonetheless be an unspecified-source transaction of more than one month duration. This electricity, if it was generated by a coal-fired resource, would not be exempt from the no-coal requirement. It seems to me that the utility would have the obligation to demonstrate that a long-term (longer than a month) contract for unspecified sources did not include any electricity from a coal-fired resource. If a utility were unable to make that demonstration for a longer term transaction, then it would be unable to attest to its compliance with the no-coal standard.

2. **Documentation of nonemitting electric generation.** If a consumer-owned utility includes electricity from the Columbia Generating Station (CGS) in its compliance with the Greenhouse Gas Neutral standard [RCW 19.405.040(1)], how will it demonstrate that (a) the utility used the electricity and (b) the utility's claim on the use of this electricity is unique? What are the transactions in which nonemitting electric generation may be obtained by a Washington utility? Is a utility likely to obtain nonemitting generation from any generating facility other than CGS? What is the appropriate role for the Bonneville Power Administration in demonstrating use of nonemitting electric generation?

It seems from the workshop discussion that the documentation of nonemitting generation from the Columbia Generating Station could be developed by BPA and its customers. This would likely be demonstrated by an attestation from BPA verifying for each utility the quantity of electricity attributable to CGS and stating that the attributes are not used anywhere else. It would be helpful for BPA and its customers to develop a proposed approach for the rule.

There did not seem to be any real-world examples involving nuclear facilities other than CGS, but it was acknowledged that additional nuclear generating capacity might be developed. An attestation requirement could be applied to those transactions.

There was also some discussion of whether any non-nuclear generating technologies could be considered "nonemitting electric generation." This issue was placed on the bike rack. Stakeholders may wish to address it in their Nov. 27 comments.

3. **Public interest requirements under the Greenhouse Gas Neutral Standard.** How will a consumer-owned utility demonstrate compliance with the requirements in RCW 19.405.040(8) to ensure that all customers are benefitting from the transition to clean energy?

This was a wide-ranging discussion. We heard views that keeping rates low for all customers was the best way to ensure that everyone benefits and that investments in clean energy will produce costs charged to every customer. We also heard that low rates are not the only driver of equitable distribution of benefits and that non-energy benefits and jobs should be factored into the compliance analysis.

It seems clear that further work will be required in order to provide a compliance standard that can actually be implemented by the auditor. A utility's compliance must be supported by its integrated resource plan and, once it's available, the cumulative impact analysis, but the requirements of this section are not limited to those two items. It does not seem, in reading the subsection, that the requirement for "equitable distribution of energy and nonenergy benefits" is restricted to "vulnerable populations and highly impacted communities," but this would benefit from further discussion.

4. **Pursuit of conservation, efficiency resources, and demand response**. How will a consumer-owned utility demonstrate compliance with the requirements in RCW 19.405.040(1)(a)(i) and (6) to pursue all cost-effective, reliable, and feasible conservation and efficiency resources to reduce or manage retail electric load? For a utility subject to the EIA, is this same requirement as the one in RCW 19.285.040(1)? For a utility not subject to the EIA, what methodology should be required to determine what is cost-effective, reliable, and feasible? How will a utility demonstrate compliance with the demand response requirement?

This discussion, while not as wide-ranging as the one on public interest standards, nonetheless addressed several subjects that will likely need to be separated as we move forward. There seem to be relevant distinctions between utilities subject to the Energy Independence Act (> 25,000 customers) and those who are not (1-24,999 customers), as well as between energy efficiency and demand response. Finally, we need to pay attention to the relationship between these requirements and the CEIP targets in RCW 19.405.060.

Energy efficiency – It seems clear that EIA-qualifying utilities will use the same standards to demonstrate compliance with CETA and EIA. For smaller utilities, the statute does not seem to require use of the EIA methodology, since it says "using the methodology established in RCW 19.285.040, *if applicable*." However, it is not clear what other methodology would be used, since the .040 methodology is that of the regional power council and is generally recognized as an appropriate standard. One element in .040 that is not in the power council method is the "pro rata" allocation of potential into a two-year target. A small utility might develop implementation schedules using the power council's analysis or other reasonable method. Another option might rely on a thorough regional or multi-utility potential assessment whose results are allocated to individual utilities.

Demand response – As noted in the workshop, the statutory language on demand response requires some interpretation. The CEIP statute requires that utilities must set targets for demand response resources, and 19.405.040(6) requires that utilities pursue demand response. It may be that the compliance requirement should be meeting the target set in the CEIP, but only if the CEIP target is set appropriately. There was also a lot of discussion about how DR could be evaluated by utilities of different types.

5. **Use of electricity from renewable resources and nonemitting electric generation.** How will a consumer-owned utility demonstrate compliance with the requirement in RCW 19.405.040(1)(a)(ii) to use electricity from renewable resources and nonemitting electric generation in an amount equal to 100% of the utility's retail electric loads? What is required in this context to "use" electricity? How is the "use" of electricity affected by purchases and sales of electricity in the wholesale market to balance a utility's customer loads with its portfolio resources on an hour-to-hour basis?

There were very different interpretations of "use" offered during the discussion. I understood one interpretation to be that electricity should be considered "used" if the utility acquired ownership of that electricity with the REC, without any need to identify the ultimate use of that electrical energy. Another suggestion was that a utility could sell electricity from its renewable resources as unspecified power and retain the REC for CETA compliance. The discussion also considered a delivery standard, where "use" would be demonstrated by an hour-by-hour comparison of load and generation/imports. This might include demonstration that the electricity was delivered to the utility's distribution system or balancing area.

Two provisions in the GHG Neutral standard factored into stakeholders' analysis: the 20 percent unbundled REC provision and the four-year compliance period. One view is that an hourly delivery standard does not provide enough flexibility to accommodate fluctuations in hydro and other renewable generation. Others contended that resource variability was accommodated by the 20 percent unbundled provision and the four-year compliance period. The existence of these mechanisms suggests to some that the remaining 80 percent of electricity must be bundled and delivered to retail customers.

It may be productive to review the Oregon and California RPS regulations, since these states use the "bundled" and "unbundled" distinctions and limit use of unbundled RECs. Oregon Department of Energy rules for bundled energy require proof of delivery to the distribution utility. The California RPS defines separate categories for:

- bundled electricity that is scheduled for delivery (Product Content Category 1),
- "firmed and shaped" electricity (PCC 2), and
- unbundled RECs (PCC3).[1]

In short, does the Washington law require PCC1 or PCC2 for the 80 percent portion? There may be other examples that are helpful in this discussion and could be discussed in comments.

6. **Retirement and tracking of renewable energy credits.** Commerce has already designated a tracking system (Western Renewable Energy Generation Information System, WREGIS) for tracking and retirement of RECs used for compliance with the Energy Independence Act (WAC 194-37-120). Are there any reasons to make a difference designation for CETA? If not, are there any changes to WREGIS retirement procedures needed to incorporate CETA? Is there any need to distinguish between RECs retired to demonstrate compliance with RCW 19.405.040(1)(a) and RECs retired for an alternative compliance option under RCW 19.405.040(1)(b)?

No stakeholders expressed an interest in using a different tracking system for CETA than the system (WREGIS) used for EIA. There may be changes in procedure required, such as the ability to indicate resources that are eligible under CETA but not EIA and to indicate retirement purpose as CETA versus EIA.

Stakeholders also discussed the relationship between the choice of tracking system and the eligibility of RECs. One thought was that the designation of WREGIS implicitly limited eligible RECs to those from generating facilities within the western interconnection. However, the tracking systems are capable of transferring RECs, so the choice of tracking systems may not limit geographic scope. According to WREGIS' operating rules, there are not presently any protocols in place to import RECs from other tracking systems, but an import function exists within the tracking system.

The import function likely does not resolve the question about a geographic limitation on eligibility of RECs. If the electricity from a very remotely located generating facility could not be delivered to a Washington customer, it may not be appropriate or consistent with industry practices to use an unbundled REC associated with that electricity.

[1] https://ww2.energy.ca.gov/2018publications/CEC-300-2018-008/CEC-300-2018-008-SF.pdf, pp. 14-15.