UE-210183

# Department of Energy

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Received
Records Management
May 10, 2024

May 10, 2024

***Filed Via Web Portal:*** *https://efiling.utc.wa.gov/Form*

Jeff Killip, Executive Director and Secretary
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, Washington 98503

RE: Docket UE-210183, Relating to Electricity Markets and Compliance with the Clean Energy Transformation Act "Use" Rules

Dear Mr. Killip:

The Bonneville Power Administration (BPA) appreciates the opportunity to provide comments on the Washington Utilities and Transportation Commission's (UTC) request for written comments on draft rules relating to the definition of "use" under the Clean Energy Transformation Act (CETA), Docket UE-210183.

BPA is a federal power marketing administration that markets wholesale power from 31 federal hydroelectric projects, one nuclear plant, and some other nonfederal power plants. BPA sells low-carbon power to over 130 preference customers across the region, 63 of which are consumer-owned utilities in Washington. BPA also sells power to privately-owned utilities throughout the Pacific Northwest and markets surplus power across the West, including to California. BPA has participated in the Western Energy Imbalance Market (EIM) since 2022 and is exploring participation in a day-ahead market. The UTC's interpretation of "use" will have implications for investor-owned utilities (IOUs) that purchase power from BPA as well as implications for the bulk transmission system and wholesale power market.

BPA begins these comments by reiterating themes from previous comments BPA submitted to the UTC and Washington's Department of Commerce (Commerce) on CETA rulemakings. Since CETA was passed and rulemakings began, BPA has consistently commented on the complexities created by the patchwork of Washington, and other states', GHG reduction and clean energy programs which take a variety of different views on the use of Renewable Energy Credits (RECs) and fuel mix to demonstrate the attributes of power sales.[1] Although these programs do not directly govern BPA, BPA does sell power

[1] For more on this point, see Comments of the Bonneville Power Administration submitted in this Docket on June 14, 2021; *see also* Bonneville Power Administration Provider of Choice Policy, Record of Decision (March 2024), at

across the West to retail utilities that are subject to these programs. Unlike virtually all other entities, BPA sells power from a system of resources - not individual generating units - and BPA does so at a system-wide emission factor.[2] The combination of these facts creates complexities and inconsistencies that are challenging for BPA to reconcile across its diverse customer base.[3] Even though BPA is not directly subject to these programs, the programs create significant administrative burden and uncertainties that, while not quantifiable, lead to additional costs to BPA's ratepayers, and which do not equate to tangible emission reduction benefits. Nonetheless, supporting customers in meeting their state GHG program requirements and regional decarbonization efforts is an important consideration in BPA's strategic plan[4] and various policy initiatives. With this background in mind, BPA shares its significant concerns with some aspects of the UTC's draft rules, as BPA believes some elements of the proposed rules could exacerbate existing challenges and further hinder the ability for BPA to support its customers in meeting their GHG requirements.

For context, BPA would like to share with the UTC some information on how RECs are created for federal system generation and how BPA conveys those RECs to its customers. This is relevant to the UTC's draft rulemaking because it sheds light on how a Washington utility could acquire a REC from the federal system.

Today, the only resources that comprise the federal system that create RECs are incremental "efficiency improvement" generation from the federal hydropower system and a few non-federal wind resources that BPA purchases the output from. RECs are created only for this generation because there are no other resources in the federal system eligible for meeting state renewable portfolio standards (RPS) programs. However, beginning in 2030, because of Washington's CETA requirements, BPA expects RECs will be created for the entire federal hydropower system to support Washington utilities' CETA requirements. Thus, in the 2030s, the magnitude of RECs created by the federal system will be significantly greater than today. Specifically, today's RECs from incremental hydro equate to about 1% of the entire federal system, while in 2030 the new Washington CETA-specific RECs from all hydrogeneration will equate to about 85% of the total federal system. This is a massive increase in RECs, and the CETA construct of a REC is a major change from (and conflict with) what a "REC" represents under other state programs.

Today, all RECs created by the federal system are conveyed on a pro rata basis to BPA's public power preference customers, consistent with BPA's long-term firm power sales contracts and to IOUs in the

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276-78 (discussing the fact that "Environmental attributes are varying, state-defined concepts," and describing some of the complexities this creates), *available at*: rod-20240321-bonneville-power-administration-provider-of-choice.pdf (bpa.gov) .

[2] See Comments of the Bonneville Power Administration submitted in this Docket on November 12, 2021.

[3] Bonneville Power Administration Provider of Choice Policy, Record of Decision (March 2024), at 276-78.

[4] See BPA's 2024-2028 Strategic Plan, Objective 3 under "Enhance the Value of BPA's Products and Services"

region through the Residential Exchange Settlement Agreement. Both the long-term power sales contracts and Residential Exchange Settlement Agreements expire at the end of BPA's fiscal year 2028 (September 30, 2028). BPA's next offering for long-term firm power sales is referred to as the "Provider of Choice" contract. Power sales under those contracts will begin October 1, 2028, and end September 30, 2044. It is currently unknown how Residential Exchange will be implemented starting in fiscal year 2029.

Importantly, BPA's Provider of Choice policy[5] states BPA will convey RECs to its public power customers commensurate with their firm power purchase amounts and rate elections, which is a shift from how RECs are conveyed today. This policy choice is one step BPA has taken to thoughtfully align how it conveys the environmental attributes of the federal system to its customers, given the variety of state programs that exist today and how those programs could evolve in the future. [6]

This policy choice also means that, whether BPA is selling power to a public power preference customer in Washington, Oregon, Idaho, or Montana, all customers will receive RECs from the federal hydropower system commensurate with their actual power purchase from BPA. Many customers are in Washington and BPA anticipates those customers will need those RECs themselves for CETA compliance. Other customers may find no value in the CETA-specific hydro REC and dispose of it or retire it as they see fit, and yet other customers may find value by transferring that REC to a utility in Washington to be used for CETA compliance as allowed by CETA rules. Because BPA's policy is to convey RECs commensurate with actual power purchases, there will also be additional RECs created by the federal system not associated with sales to public power customers. BPA envisions it could convey those RECs with other power sales or otherwise convey, retire, or dispose of the RECs.

With that context, BPA provides the following comments on the UTC's draft rules.

**1) Regarding WAC 480-100-6XX generally**

BPA reiterates its February 15, 2024, comments that it supports the UTC adopting rules on "use" consistent with the rules adopted by Commerce. Commerce's interpretation is supported by the plain language of RCW 19.405, which creates four-year compliance periods.[7] Regarding the currently proposed UTC language, BPA believes that the monthly requirement, in particular, creates a standard that goes beyond the standard created by RCW 19.405.

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[5] See Provider of Choice Final Policy, March 2024, *available at* https://www.bpa.gov/-/media/Aep/power/provider-of-choice/provider-of-choice-policy-march-2024.pdf.
[6] See Bonneville Power Administration Provider of Choice Policy, Record of Decision (March 2024), at Section 8, issue 128, p. 272-274 (discussing BPA's Provider of Choice approach to conveying RECs, and reasons therefor).
[7] See Comments of the Bonneville Power Administration on June 29, 2020.

BPA believes it was the intent of the legislature to establish four-year compliance periods because, in achieving the state's emission reduction goals, other factors like reliability and cost needed to be taken into consideration. This is particularly important in the context of a state where a significant amount of the electricity is generated from hydropower, which can vary from year to year. This variability was demonstrated just last year when low precipitation and snowpack paired with the timing of runoff created greater dependence on market purchases and fossil fuel generation.[8] A monthly, or even annual, demonstration of compliance could lead to utilities incurring additional alternative compliance costs or penalties under CETA due to the natural variability in the portfolio of renewable resources that the utility planned on to meet its load. A four-year compliance period ensures reliability and cost considerations are also factors in the real-time decisions that a utility must make to serve its load. BPA does not believe the four-year compliance period was created for the limited purpose of easing administrative reporting burdens.

In addition to the monthly requirement conflicting with the plain language of RCW 19.405 and frustrating the intent of the multiyear compliance period, such a requirement will also result in inefficient build-out of renewables and transmission. This will, in turn, increase the challenges and costs for decarbonizing the electricity sector and economy.

As BPA also pointed out in its December 2, 2020[9] comments to the UTC (and it still holds true), the problem with a monthly requirement, as opposed to Commerce's procurement-based approach, is that it would incentivize the construction of additional transmission lines for the primary purpose of compliance with meeting the monthly requirement rather than serving new loads, improving overall grid reliability, or congestion relief. The construction of new transmission lines is both costly and controversial. It can take 20 plus years to site and build a major transmission line and 5 plus years for even minor upgrades. As the region shifts toward a cleaner electricity system and electrifies loads, renewable resources should first be built in locations that are the most cost-effective, making use of existing available transmission and providing valuable reliability benefits to the grid. A monthly requirement does not support the least-cost transition towards decarbonization. Commerce's procurement-based approach provides time for new transmission to be considered and built where needed for grid reliability as additional renewable resources are built and as additional states or the nation implement GHG regulations.

Further, BPA foresees that a monthly requirement would exacerbate transmission planning challenges and could create an incentive to deviate from industry best practices for maintaining reliability. North

[8] BPA's preliminary assessment of its fuel mix for calendar year 2023 shows about 10% of the fuel mix was derived from market purchases, compared to closer to 3% in the several years prior to 2023.
[9] See comments of the Bonneville Power Administration on December 2, 2020.

American Electric Reliability Corporation (NERC) Standards for transmission planning include performance requirements to be able to withstand a defined set of outages for expected load levels. Utilities need to be able to adjust their operations in response to maintenance outages, unplanned outages of transmission or generation facilities, and severe weather so that the transmission system remains in a secure state following the next potential contingency. To preserve transmission reliability, utilities may need to increase or decrease generation output levels of resources in particular locations during certain events. For example, planned outages for transmission maintenance are necessary to keep the transmission system in a state of good repair, but challenging to coordinate given the existing constraints that need to be accommodated across impacted parties. If IOUs must meet a monthly requirement under CETA, that would add one more factor that BPA is asked to consider when planning these outages in addition to influencing when the IOUs themselves would perform maintenance. A monthly requirement could create friction between a utility concerned with meeting CETA requirements and BPA performing necessary system maintenance to preserve transmission reliability.

Additionally, long-term procurement commitments are typically the primary support for investments in generation resources. To incentive these long-term commitments, Washington utilities should have assurance that they will be able to fully claim under CETA the clean generation from their long-term investments. They should have assurance that those resources can participate fully in broad regional markets to optimize dispatch closer to real time without concern that the optimal dispatch could hinder a utility's compliance under CETA. This directly supports the goal of decarbonizing at lower cost to ratepayers. A good example of this is renewable generation in California today, where solar investments in particular are consistently resulting in overgeneration to California load in the hours of 10am-4pm.[10] This clean generation is optimized in the CAISO's market and able to serve other loads and displace other generating resources, subject to transmission constraints. As the operator of a large hydrogeneration system, this can enable BPA to save water for other times of the day or year when solar generation is not as high. In those times, clean hydropower can be generated, displacing fossil fuel generation. Collectively, this contributes to lower cost power and lower cost decarbonization, benefiting Pacific Northwest consumers including those in Washington.

**2) Regarding WAC 480-100-6XX (6)**

BPA believes that it may be reasonable to allow a utility to pair RECs with power attributed in an organized market and use that to claim primary compliance under CETA where the attributed power is surplus to attributed amounts already contractually committed to other utilities. The challenge is how to identify the amount of surplus attribution because attribution, which was created for carbon pricing programs, is at a statewide level, not at an individual utility (load responsible entity) level. BPA encourages the UTC to engage in further conversation with market operators and industry to understand whether and how that might be possible.

BPA clarifies that the market design for specified source attribution for the CAISO's EIM/EDAM and SPP's Markets+ is intended to work for a carbon pricing program, like Washington's cap-and-invest program, and not necessarily for CETA. GHG attribution to a carbon pricing state can be from any specified source, which may include renewable or non-emitting generating sources but is not limited to that. When resources are attributed to a state with a carbon pricing program, the attribution is to load in the state *generally* and not to a specific utility. Neither market design was intended to reconcile attributed resources to specific utilities because, in both California and Washington's carbon pricing programs, the compliance obligation is assigned to the electricity importer/First Jurisdictional Deliverer, not to load. Thus, it is not necessary to track the amounts of power attributed to the state from a specific resource back to a specific utility.

Both market designs provide a path for attribution of power that is contractually committed to a load in the state. In SPP's Markets+, this is referred to as Type 1 (a or b) attribution. In the CAISO's EIM/EDAM, it is referred to as committed capacity. Other amounts of power may also be attributed to the state. These amounts may reflect surplus power from a resource. However, they may also be a result of market design limitations where resource amounts are dispatched even though those amounts were contracted to another entity or intended to meet native load. This situation could occur with both SPP and CAISO's market designs, but BPA believes will be particularly prevalent in the CAISO's market given issues with its current design for GHG accounting. This is because the CAISO market gives the market participant limited control over how much power can be attributed to a state, so attribution could include power that was associated with contracted-for sales to non-Washington utilities.

Relating the market design - and its inherent limitations - to the UTC's proposed rules, BPA has some specific concerns. The UTC's currently proposed language is broadly written and BPA foresees that, without more specific language, the rules could create competing and irreconcilable claims on federal system power and RECs across investor-owned and public utilities in Washington.

First, where attribution to Washington is based on a contractual commitment to an investor-owned utility, the language in section (6) appears unnecessary to BPA because that arrangement should fall under the "single transaction" covered under section (5) of the draft rules. Therefore, it should be unnecessary to try to reconcile the actual market attribution against the contracted-for amounts, and it could actually complicate a utility's demonstration under section (5) if it cannot be confirmed that the contracted-for amounts were not fully attributed (which could be the case).

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[10] See the Supply Outlook for the California ISO, available at [https://www.caiso.com/TodaysOutlook/Pages/supply.aspx](https://www.caiso.com/TodaysOutlook/Pages/supply.aspx)

Second, the language seems to allow utilities to acquire RECs from the federal system from any source and claim it against any amounts attributed, even where those amounts were contractually committed to another utility. As described above, some of the attribution will be Type 1 or committed capacity for another utility in Washington who is likely using the associated RECs for CETA compliance. Some of the attribution could also be a result of market design issues and was contractually committed to a utility in another state who may be using RECs associated with that contract for their own purposes. More limiting language is needed to avoid competing claims and double counting of emissions and attributes in these circumstances.

Thus, BPA suggests the section (6) be specific to power attributed to Washington in an organized market that is surplus to market participants' loads and contractual commitments. This appears to support the intent of section (6) while avoiding conflicting claims on attributed power.

To provide additional context on the complications BPA is concerned with, it helps to understand the different scenarios under which BPA foresees that federal power could be attributed to Washington via an organized market and to connect those scenarios with BPA's Provider of Choice policy for conveyance of RECs, as described at the beginning of these comments.

- Scenario 1: Power contracted to BPA's public power preference customers in Washington under long-term power sales contracts. SPP refers to this as Type 1 while the CAISO refers to this as committed capacity. Independent of the market design for attribution to Washington, BPA's customers will also receive RECs associated with the power sale in accordance with their Provider of Choice contract with BPA.

- Scenario 2: Power BPA has sold bilaterally to an IOU or consumer-owned utility in Washington. This is also what SPP refers to as Type 1 and the CAISO refers to as committed capacity. BPA envisions such an arrangement could also include RECs, if RECs are available.

- Scenario 3: Other power that is not connected to a specific contract to Washington load. SPP refers to this as Type 2, and it largely correlates with power BPA would identify as surplus. Under the CAISO's design it is just general attribution and may not correlate to power BPA identifies as surplus.
    - To the extent the power attributed to Washington was associated with a long-term power sale to a BPA public power preference customer not located in Washington, that BPA customer will receive RECs associated with that power (and independent of the market design) in accordance with their Provider of Choice contract with BPA.

- To the extent the power attributed to Washington was surplus federal power, BPA may have retained RECs associated with that power that may be available to transfer to an IOU to pair with the attribution.

- Scenario 4: Resale of surplus federal power,[11] where an entity purchased power from BPA and would like that power to be made available in the market, whether because the entity has resold that power under a forward-contract or would just generally like to make it available. It is not clear at this time exactly what the market mechanics of this arrangement will look like, but BPA anticipates that the markets would attempt to accommodate these types of transactions for attribution purposes. Depending on the specific circumstances, the resale of power and conveyance of RECs could align with any of the three scenarios above.

Regardless of which scenario(s) above that BPA makes federal resource offers for meeting load in Washington in an organized market, the attribution amount awarded by the market will not necessarily delineate what part of the attribution award was for resource amounts contracted to load (and which specific load(s)), surplus resource amounts, and other amounts. BPA is not aware that either the CAISO or SPP intended to make this information available to market participants. Again, BPA encourages the UTC to engage in further conversation with market operators and industry to understand whether and how it might be possible to identify the amount of attribution that was surplus.

We appreciate the time from UTC spent explaining the intent of the draft rules. We recognize these comments are complicated and that market design is evolving quickly. BPA staff are willing discuss this further with UTC staff. Please contact me at 503.230.4358 or Melissa Skelton at mdskelton@bpa.gov if you have any follow up questions or discussion.

Sincerely,

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[11] Section 5(b) of the Northwest Power Act, 16 U.S.C. § 839c(b)(1) precludes utilities from reselling Firm Power. Thus, only a minimal amount of power sold under BPA's "slice" product can be resold. For more information, see Comments of the Bonneville Power Administration to the UTC and Commerce on September 17, 2021.