AWEC

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Via Electronic Submission

Elliot Mainzer
Administrator and Chief Executive Officer
Bonneville Power Administration
911 NE 11th Avenue
Portland, OR 97232

Re: July 28-30, 2020 TC-22/BP-22/EIM Phase III Workshops

Dear Administrator Mainzer:

The Alliance of Western Energy Consumers ("AWEC") appreciates the opportunity to provide feedback regarding Bonneville Power Administration's ("BPA or "Agency") July 28-30, 2020 TC-22/BP-22/EIM Phase III workshops. Below, AWEC addresses the following July 28-30th workshop topics: Requirements for Participating and Non-Participating Resources; Participating Resources: Base Schedule Timeline; Generation Inputs: Energy Imbalance/Generation Imbalance; Generation Inputs: Persistent Deviation/Intentional Deviation; Revenue Requirement: Leverage Policy Discovery; Revenue Requirement: Regulatory Assets; Power Rates: Tier 2 Rates; and Power Rates: EIM Benefits and Charges in Power Rates.

Requirements for Participating and Non-Participating Resources

BPA provides two alternatives in order to address the following two Requirements for Participating and Non-Participating Resources issues: "[w]hat type of service agreement is needed to allow resources to become Participating Resources…[and] [w]ill Participating Resources be required to reserve transmission, and if so, how much and what type?"[1/]

BPA Staff's recommends Alternative 1 Status Quo which results in BPA including language in its Tariff (attachment Q) that requires Participating Resources to have either a Network Integration Transmission Service ("NT") agreement or Point to Point ("PTP") enabling agreement with BPA. We understand that if a member already has a transmission contract with BPA then it appears that under Alternative 1, that would be the basis of becoming a Participating Resource. Additionally, it is our understanding that under Alternative 1, if the member is not yet a BPA transmission customer then they would need to execute an enabling agreement and develop that relationship with BPA. Further, it appears that under Alternative 2,

[1/] Bonneville Power Administration, TC-22, BP-22 and EIM Phase III Customer Workshop, at slide 19 (July 28, 2020).

they would only be able to be a price taker with the new, simpler EIM Participating Resource contract structure but if they wanted to submit schedules, they would need the standard enabling agreement. Notably, Alternative 2 is not the standard approach used by other EIM entities. Ultimately, Alternative 1 appears to be the least administratively burdensome path without introducing additional risk.

Participating Resources: Base Schedule Timeline

AWEC currently does not oppose BPA Staff's recommendation to adopt the T-57 timeline for financially binding schedules, which, among other things, will minimize any seams issues with other EIM entities. Notably, this alternative will result in changes for those who would customarily have a financially binding point at T-20. Further, the benefit of an additional seven minutes offered from moving to T-50 does not appear to outweigh the complications and increased burdens associated with moving the financially binding point to T-50. However, AWEC continues to discuss this issue with members that operate cogeneration units to better understand whether the shortened timeframe (T-20 versus T-57) will reduce their ability to accurately schedule when also managing industrial processes. Tentatively, we believe that moving to T-57 is workable, but such a move must be combined with revisions to the Generation Imbalance Services structure in order to ensure that the market—not penalties—reward or dissuade poor scheduling practices. Notably, all EIM entities using T-57 do not have a Generation Imbalance penalty structure, nor do they need one as discussed more fully below.

Generation Inputs: Energy Imbalance/Generation Imbalance Service Rates

According to the July 28th workshop presentation, BPA is proposing three Energy Imbalance ("EI")/Generation Imbalance ("GI") alternatives within EIM participation. Notably, all of the proposed alternatives assume sub-allocation of the base codes for EIM. Therefore, according to BPA, "in alternatives where EI/GI Deviation Bands are retained, bands would be in addition to the sub-allocated charges/credits."[2/]

EI and GI apply when a load or resource schedules deviate from plan beyond pre-defined levels and are intended to incentivize accurate scheduling. Alternative 1, as proposed by BPA, retains the status quo. Accordingly, this alternative relies on bands of applicability and a Mid-C index price in addition to sub-allocated LMP/LAP pricing. There are numerous cons associated with Alternative 1, including but not limited to, potentially fewer bilateral transactions in real-time at the Mid-C trading hub as more entities join the EIM, and thus the current price index for EI/GI deviation bands may not reflect the "true" value of energy, and overall increased risk. AWEC is opposed to Alternative 1.

A more reasonable approach is for BPA to move forward with an alternative that results in shifting pricing to be wholly consistent with the EIM framework and relying on LAPs and LMPs, as found in Alternatives 2 and 3. It is further reasonable that the bands be removed in

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2/ Id. at slide 74.

order to minimize inconsistent pricing approaches across the EIM footprint and ease the transition to the T-57 timeline shift noted above. As such, AWEC supports Alternative 3: Remove Existing EI/GI Deviation Bands. Sub-allocation of the base codes will likely provide sufficient incentive to schedule accurately in this new paradigm, as it does for other EIM Entities. AWEC is appreciative to hear that this is also BPA Staff's leaning and we fully support Staff in this regard.

EIM market signals should encourage optimal generation dispatch. The various EIM imbalance base charges provide a significant incentive to generate resources to plan or dispatch order when resources are quickly dispatchable. In addition, when imbalance occurs, the EIM pricing mechanisms provide appropriate compensation for the energy provided. In the case of some of our members, whose resources operate as part of cogeneration facility connected to industrial load, dispatchability is minimal and the generation fluctuates more around industrial operations. If generation trips off or mismatches to plan it is not out of a decision to intentionally lean on the system but really a disruption to the facilities' primary purpose operations or a small fluctuation to operations that may be slower to translate to a generation schedule change due to lack of assurance that the generation change is longer lasting. These are not penalty-worthy actions. The imbalance charges through the EIM are the correct level of costs to pass along in these cases. Adding penalties to these imbalance charges serves only to extract additional payments from struggling industries.

In the event that BPA determines there is significant decrease in scheduling accuracy over the first-rate period of operations under the EIM, BPA can revisit this proposal and explore some potential reintroduction of the bands at that time. Thus, moving forward with Alternative 3 provides BPA with the flexibility necessary to be successful in the EIM while balancing potential risk. In the alternative, if BPA proceeds with Alternative 2 and retains the bands, revisions to the structure will be reasonable and necessary. As such, any revisions must recognize that customers will be participating in a new scheduling paradigm and may be exposed to increased generation imbalance.

Generation Inputs: Persistent Deviation/Intentional Deviation Penalties

BPA proposes three alternative ways to approach Persistent Deviation ("PD") and Intentional Deviation ("ID") within EIM participation: Alternative 1: Status Quo, Keep the ID and PD penalties; Alternative 2: Remove one or both of the ID and PD penalties; and Alterative 3: Modify the ID and PD penalties. PD applies to loads and Dispatchable Energy Resources and is intended to penalize those entities for accumulate error in one direction or the other (inconsistent with the rate case assumption of energy imbalance zeroing out over time). Whereas ID applies to Variable Energy Resources and is similarly intended to penalize those entities for scheduling inaccuracies.

It is likely that the EIM market will be able to provide the appropriate behavioral incentives such that reliance on this existing PD/ID framework will not be needed. As such, the PD/ID framework should be removed altogether. It is worth noting that although BPA's

Balancing Authority Area ("BAA") is unique compared to other EIM Entities, other entities do not rely on a PD/ID penalty framework to bolster their loads and resource scheduling accuracy. Again, the sub-allocated EIM charge codes in discussion will provide sufficient incentive to schedule accurately and sufficient compensation when imbalance occurs. In the alternative, if modifications to the penalties are considered, as described in Alternative 3, then such modifications must recognize the EIM environment in which customers will be participating.

Revenue Requirement: Leverage Policy Discovery

During the July 28th workshop BPA Staff shared a disquieting revelation regarding variation between forecast and actual leverage levels assumed in the last rate case. According to the workshop materials, the variances are "driven by [BPA's] interpretation of how assets and debt are categorized, defined and/or calculated."[3/] According to BPA Staff, assumptions regarding deferred borrowing and how the borrowing actually moves through BPA's finances resulted in BPA's leverage improving beyond target in FY 2019.

Notably, in the previous rate case there was an assumed level of revenue financing in Transmission rates to assist in improving Transmission's leverage position. Given the information presented during the July 28th workshop it is unclear at this time what BPA's BP-20 rates would have been if BPA implemented the changes currently proposed to be implemented in BP-22. Undoubtedly, there is always the potential for unintended consequences when implementing new policies and quick corrective action in response to such instances is appreciated. Nonetheless, it is concerning that BPA failed to identify this issue during the Leverage Policy development period.

Revenue Requirement: Regulatory Assets

BPA's willingness to explore possible changes to its assumptions regarding amortization periods for its regulatory assets, specifically in regard to potentially reducing the amortization period associated with the Columbia River Fish Mitigation program, is appreciated. In accordance with comments previously submitted by AWEC, this decision by BPA is prudent and reasonable.

Power Rates: Tier 2 Rates

BPA selected a variety of approaches for how it meets its Tier 2 obligations over the years. In some rate periods, a purchase was made for the rate period immediately before it starts. In other rate periods, a purchase was made in advance of a rate period and in anticipation of need, and then remarketed because the need did not materialize. Additionally, in other instances, no purchase was made and thus, the BPA system was assumed to meet the obligation.

3/ Id. at 145.

The Tiered Rate Methodology ("TRM") provides guidance on using available Tier 1 system to meet Tier 2 loads, in the form of allowance to do so. It is unclear at this time whether the TRM in conjunction with Section 5(f) of the Northwest Power Act encompasses the totality of considerations driving BPA's market purchase decisions in order to meet Tier 2 needs. Thus, it is reasonable for BPA and stakeholders to explore whether there are additional policies that may contribute to this decision. Additional clarity on this issue would help elucidate possible alternatives to including a carbon adder in the Tier 2 cost structure.

For example, is BPA statutorily prohibited from making a purchase to meet the Tier 2 load and then selling the surplus firm to the higher value market, reflecting the sale's low carbon attribute? Although in this example the need to include a carbon adder for the market purchase made to meet Tier 2 loads would likely still exist, it may also produce the greatest value for BPA. If that was the case, would it be considered, or would it be off the table when there is available firm surplus to meet Tier 2 loads? Although this discussion may not be ripe for conclusion in this rate period, AWEC nonetheless looks forward to further engaging with BPA on this topic.

Power Rates: EIM Benefits and Charges in Power Rates

According to the July 30th workshop presentation, revenue credits associated with sales of surplus power into the EIM would flow to the Non-Slice cost pool and revenue credits associated with sales of balancing reserves into the EIM would flow into the Composite cost pool.

In light of the Agency's lack of experience marketing in the EIM, BPA Staff is leaning towards setting EIM net dispatch benefits to be equivalent to expected ongoing costs in BP-22. Thus, according to the July 30th workshop presentation, although EIM start-up costs are currently being incurred, Power Services expects an additional $2.4 million per year of ongoing costs once participation in the EIM begins. As a result, BP-22 Net Secondary Revenue increases approximately $2.4 million per year. BPA's conservative initial estimate is understandable given the lack of explicit interactions in the EIM market and the condensed time period to derive benefits. However, it appears that there could be additional effort made on behalf of the Agency to model the potential benefits in the BP-22 rate period.

At this time, BPA has yet to provide a market strategy for if and when the Agency enters the EIM. Thus, BPA Staff's comments expressing the difficulties associated with modeling the benefits of joining the EIM are concerning. It is equally concerning that BPA appears to be relying on a low estimate of benefits in rates with any amount derived above that level to go towards reserves, offsetting the possibility of a Cost Recovery Adjustment Clause or Financial Reserve Surcharge or possibly contributing to a Reserves Distribution Clause that may or may not be implemented. As such, AWEC strongly urges BPA trading floor and rates staff to work collaboratively to develop a model for estimating a level of EIM benefits to include in Power rates. Alternatively, BPA should reevaluate its risk tools to acknowledge this conservative approach towards EIM benefits.

According to the July 30th presentation, "[r]eserves (balancing and contingency) are 'off-the top' obligations for the [Federal Columbia River Power System], with the revenue credit going to Slice and non-Slice customers in the composite cost pool."[4/] Further, "[a]n 'off-the-top' obligation for Slice customers means the Slice 'capability' is reduced accordingly…[and] [s]lice customers share in the operational obligation and receive a share of the associated revenue."[5/]

BPA Staff shared three options for how the Agency may treat the Slice portion of benefits associated with energy and capacity sold into the EIM. Option 1 treats both the energy and capacity as "off the top" obligations of the system modeled for the Slice customers, whereas Option 2 treats only the capacity as an "off the top" obligation. Finally, Option 3 treats neither the capacity nor the energy as an "off the top" obligation. As noted by BPA Staff, Option 3 is not consistent with the Tiered Rates Methodology. Further, Option 1 requires a method for separating out EIM energy deployments that are balancing reserve related as opposed to those from the firm surplus inventory. In order to properly evaluate the three options presented, it would be helpful to know how challenging an implementation issue this may be. As currently presented to stakeholders, this prerequisite appears to be a significant component to making Option 1 viable. Providing comparable treatment to the products so that they experience similar impacts from BPA's possible entry to the EIM is a worthy goal. Nonetheless, additional information is required in order to determine whether such a goal is attainable. Ultimately, if such a goal is not attainable, Option 2, in which only the capacity is treated as an "off the top" obligation and energy deployments are not, is reasonable.

Finally, BPA Staff presented on EESC Charge Codes specifically in relation to how EESC sub-allocated charge codes from Transmission Services would be treated in Power Rates. From the information provided at this time, it appears appropriate to allocate the EESC sub-allocated charge codes to the Non-Slice cost pool. Further, it is reasonable that if Slice customers ultimately benefit from EIM dispatches, then such customers should also bear some portion of the applicable sub-allocated charge codes.

/s/ John Carr
Executive Director
Alliance of Western Energy Consumers

4/ Bonneville Power Administration, TC-22, BP-22 and EIM Phase III Customer Workshop, at slide 92 (July 30, 2020).

5/ Id.