UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

BEFORE THE

BONNEVILLE POWER ADMINISTRATION

2022 Joint Power and Transmission Rate Proceeding	**BPA Docket No. BP-22**

DIRECT TESTIMONY OF JOINT PARTY (JP) 01

NORTHWEST & INTERMOUNTAIN POWER PRODUCERS COALITION AND RENEWABLE NORTHWEST

WITNESSES:

Henry Tilghman and Michael Goggin

SUBJECT OF TESTIMONY:

BPA's Proposed Transmission and Ancillary Services Rates and Policies

February 3, 2021

DIRECT TESTIMONY OF

HENRY TILGHMAN AND MICHAEL GOGGIN

Witnesses for Joint Party 01

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DIRECT TESTIMONY OF

HENRY TILGHMAN AND MICHAEL GOGGIN

Witnesses for Joint Party 01

SUBJECT: BPA's Proposed Transmission and Ancillary Services Rates and Policies

Section 1: Introduction and Purpose of Testimony

Q. Please state your name and qualifications.

A. My name is Henry Tilghman, and my qualifications are contained in BP-22-Q-JP01-01. I am primarily responsible for Sections 2 and 4-7 of the testimony.

A. My name is Michael Goggin, and my qualifications are contained in BP-22-Q-JP01-02. I am primarily responsible for Section 3 of the testimony.

Q. What is the purpose of your testimony in this docket?

A. The purpose of our testimony is to support the recommendations of the Northwest & Intermountain Power Producers Coalition ("NIPPC") and Renewable Northwest ("RNW") with respect to the Bonneville Power Administration's ("BPA") proposals for the Fiscal Year ("FY") 2022-23 rate period.

Q. Please summarize your testimony.

A. Each section of the testimony identifies specific concerns with BPA's proposals and offers alternative recommendations. Section 2 of our testimony addresses our concerns regarding BPA's proposed allocation of Energy Imbalance Market ("EIM") costs and benefits—namely, that BPA allocated the EIM costs to transmission customers despite the benefits being allocated to power customers. We recommend that BPA allocate certain costs of joining and participating in the

EIM to power customers. In addition, we recommend that BPA provide a credit to Ancillary and Control Area Services ("ACS") rates from EIM revenues in an amount up to the costs of the generation inputs capacity, and as a credit for BPA's accepted EIM bids to prevent over-collecting from transmission customers its capacity and opportunity costs.

Section 3 explains that BPA overstates the amount of balancing reserve capacity needed, particularly for purposes of the Variable Energy Resource Balancing Service ("VERBS") rate. According to our analysis, BPA could hold approximately 78% less balancing reserves and still comply with applicable North American Electric Reliability Corporation ("NERC") standards.

Section 4 discusses our concerns with BPA's proposed allocation of costs associated with its Grid Modernization Program ("Grid Mod"), given that power customers would receive revenue benefits from the Grid Mod projects, but transmission customers would not. We propose two different cost allocation methods, both of which are more equitable than BPA's proposal.

Section 5 discusses our concerns with BPA's proposed increase to the Dispatchable Energy Resource Balancing Service ("DERBS") rate, which amounts to rate shock. We recommend that BPA mitigate this rate increase, including by not subjecting dispatchable energy resources ("DERs") that participate in the EIM to charges for Station Control Error ("SCE"). In addition, we explain how BPA will be able to monetize the capacity set aside for non-regulating balancing reserves once it joins the EIM.

Section 6 details our concerns with BPA's proposed transmission losses policy and offers our recommendations regarding the development of both a concurrent loss return practice and a fair price for the financial settlement of loss returns. Given BPA's plan to implement concurrent loss returns later in the rate period, our proposal would save BPA time and resources it would otherwise spend developing a temporary rate.

Finally, Section 7 discusses our concerns that BPA's revenue financing proposal would create intergenerational *in*equities by having current ratepayers bear the brunt of funding capital investments that would last for decades. If it cannot be addressed with spending controls, BPA's need for capital is better addressed through changes to its access to non-federal debt or U.S. Treasury borrowing capacity. If BPA proceeds with revenue financing, it should 1) treat investments that are funded in this manner similarly to expenses and verify that they do not contribute to depreciation expense, and 2) include a mechanism to reduce rates by the amount of revenue financing included therein if Congress increases BPA's borrowing authority before or during the BP-22 rate period.

Q. Could BPA recover more than its total system costs?

A. Yes. BPA is proposing to over-collect its opportunity costs related to the EIM and overstates the amount of balancing reserve capacity needed, which also could result in BPA recovering more than its actual total system costs. It is our understanding that if BPA's remaining rates accurately recover its costs, then this overcollection and overstated reserve needs could result in BPA's revenues exceeding its total system costs.

<u>Section 2: Allocation of EIM Costs and Benefits</u>

Q. What is the purpose of this section of your testimony?

A. This section supports our recommendations with respect to BPA's proposals related to the development of rates in preparation for BPA's participation in the EIM.

Q. What are some of the ratemaking principles that apply to BPA?

A. In setting rates, terms, and conditions, our understanding is that BPA must adhere to cost causation principles, the statutes applicable to BPA, and comparability.

Q. With these principles in mind, please summarize your conclusions and recommendations regarding the allocation of EIM costs and benefits.

A. Our conclusions and recommendations are as follows:

1. We oppose BPA's proposals for allocating the costs of EIM participation. In our view, these proposals violate cost causation principles, unduly discriminate against non-federal energy resources (including variable energy resources ("VERs")), are inconsistent with actual system operations, and fail to allocate costs equitably and comparably.
2. We recommend that BPA reconsider its cost allocation analysis in its allocation of EIM costs and benefits and allocate certain costs of joining and participating in the EIM to power customers.
3. We recommend that BPA implement mechanisms to credit transmission customers' ACS rates who underwrite the cost of balancing reserve capacity to avoid overcollecting BPA's costs via double-counting capacity and opportunity costs.

Section 2.1 Cost Allocation Principles in the Context of the EIM

Q. What cost allocation principles did BPA apply in developing its allocation of EIM costs and credits among power rates?

A. BPA "considered six general principles in developing the allocation of costs and credits" among power rates.[1] Those principles are:

1. Full and timely cost recovery, considering cost causation while balancing with simplicity.
2. Develop an understandable and transparent methodology that we can build upon as we gain experience in the market.
3. Feasibility of implementation, recognizing forecasting constraints and administrative implications.
4. Costs and benefits are allocated among cost pools consistent with the Tiered Rates Methodology and power products purchased from BPA.
5. To the extent possible, treat directly connected and transfer customers comparably.
6. Maintain a similar level of exposure to actual market conditions as is included in power products today.[2]

BPA then went on to allocate the EIM costs and benefits among power customers according to those principles.[3]

Q. Did BPA apply the same cost allocation principles to transmission rates?

A. No. In allocating EIM charge codes to transmission customers, BPA applied different cost allocation principles as set forth below:[4]

Principle 1: Full and timely cost recovery, considering cost causation while balancing with simplicity.

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1 Traetow *et al.*, BP-22-E-BPA-33 at 4.
2 *Id.*
3 *Id.*
4 Pleger *et al.*, BP-22-E-BPA-32 at 6.

> Principle 2: Develop an understandable and transparent methodology that we can build upon as we gain experience in the market.
>
> Principle 3: Feasibility of implementation, recognizing forecasting constraints and administrative implications.
>
> Principle 4: Equitable cost allocation between Federal and non-Federal users of the transmission system.
>
> Principle 5: Behavior-driven cost causation where practical, to incentivize appropriate market behaviors.
>
> Principle 6: Mitigate seams and the potential for charge code allocation misalignments with other EIM entities.[5]

The first three principles BPA used to apply charge codes to transmission rates are identical to those used to apply charge codes to BPA's power rates. Most notably, in allocating costs and credits associated with the EIM in BPA's power rates, BPA did not consider Principle 4, whether its proposal resulted in an equitable allocation of costs and benefits between Federal and non-Federal users of the transmission system.

Q. Are there additional cost allocation principles that BPA should have considered?

A. Yes. In July 2012, BPA and its customers developed "Cost Assignment Principles Applicable for Acquisitions and Services That Benefit Both Power and Transmission Functions" (the "Cost Assignment Principles"). These principles were intended to be applied in situations where an acquisition or service benefited both Power and Transmission functions.[6] At the time, BPA was exploring

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5 *Id.*

6 BPA, COST ASSIGNMENT PRINCIPLES APPLICABLE FOR ACQUISITIONS AND SERVICES THAT BENEFIT BOTH POWER AND TRANSMISSION FUNCTIONS 1 (2012) [hereinafter Cost Assignment Principles] (see attached BP-22-E-JP01-01-AT02 at 1-7).

potential non-wires solutions to transmission constraints.[7] Traditionally, BPA addressed transmission congestion by upgrading existing transmission lines or building new ones and allocating the resulting costs to transmission customers. However, while exploring non-wires solutions to transmission constraints, BPA noted that some of those solutions might not follow the "traditional flow" of cost allocation.[8] As a result, BPA and its customers worked together to develop a set of cost allocation principles that would fairly allocate the costs of non-wires solutions between BPA's Power and Transmission functions. After feedback from customers, BPA determined that it would use the principles as an internal guide for business cases that provided benefits to both the Power and Transmission functions, even though BPA declined to apply them in the BP-14 rate case.[9]

Q. What are the Cost Assignment Principles that were developed in 2012?

A. The Cost Assignment Principles are:

1. All costs collected through rates.
2. Cost established in Integrated Program Review ("IPR") (or its successor) with assignment of those costs established in a rate case.
3. Applicable to new costs beginning in BP-14.
4. Transparent causation.
5. Forward-looking cost assignment based on the best-available information at the time of the decision.
6. Cost assignment based on each business unit's needs and the associated benefits received from meeting those needs.

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7 *Id.* at 1.
8 *Id.*
9 *Id.* at 3.

7. Annual assignment percentage set on quantifiable benefits received relative to total quantifiable benefits.

8. Quantifiable benefit measured with macro benefits are expected to provide benefits equal to at least 2% of the annual cost.

9. General assignment of costs will be used when the necessary information is not available.[10]

Q. Did BPA apply those principles to the allocation of EIM costs?

A. No. Even though BPA has described its participation in the EIM as a non-wires "cost-effective alternative for managing moderate amounts of intra-hour congestion across the transmission system"[11]—which is precisely the criteria for which these alternative cost allocation principles were developed—BPA did not apply these principles to the allocation of EIM costs. In the Record of Decision on EIM Policy, BPA even compared the costs and benefits of joining the EIM to other non-wires solutions, including demand response, battery storage, and generation redispatch.[12] BPA's failure to apply the Cost Assignment Principles to the EIM cost allocation—despite having developed those principles for such a situation—is arbitrary.

Q. Has BPA articulated why it did not apply the Cost Assignment Principles to the EIM cost allocation?

A. Yes. In response to Data Request NI-BPA-20-30, BPA provided the following explanation:

> The [Cost Assignment Principles] was a pre-decisional document created by BPA Staff for discussion purposes only with customers. It was a concept paper and was never adopted as a formal policy or

[10] *Id.* at 4.

[11] BPA, ADMINISTRATOR'S RECORD OF DECISION, ENERGY IMBALANCE MARKET POLICY 104 (2019) [hereinafter EIM ROD].

[12] *Id.*

> decision directing BPA ratemaking decisions. BPA's rate determinations and allocation decisions are determined in BPA's rate proceedings. Additionally, the context of that concept paper is not applicable to the cited testimony. Specifically, the concept paper considers how certain costs could be functionalized between business units, not how each business unit would allocate its costs to its respective products and services. The cited testimony explains the principles and applicable documents that we used to allocate EIM-related power costs and credits to power products and services. As stated in bullet point four of our testimony on page 4, the Tiered Rates Methodology is the relevant decision document that applies in this situation.[13]

Q. How do you respond to BPA's explanation?

A. With respect to BPA's first point that the Cost Assignment Principles were never adopted as a formal policy, we would suggest that BPA staff could nonetheless propose for the Administrator's consideration applying the principles in this proceeding. Given BPA's response that "BPA's rate determinations and allocation decisions are determined in BPA's rate proceedings," it seems reasonable and appropriate for BPA to consider applying those principles in the context of this rate proceeding as it is making allocation decisions. In any case, BPA has not provided an adequate explanation as to why it went through all the effort to develop the Cost Assignment Principles if it did not plan to use them. As for BPA's second point, we disagree that the Cost Assignment Principles should be limited to functionalization of costs between business units, as opposed to also offering guidance on how the costs should be allocated to each business unit's costs and services. The Tiered Rates Methodology may be a relevant decision document in considering the allocation of costs to power rates.

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[13] BPA Response to NI-BPA-30-20, (see attached BP-22-E-JP01-01-AT01 at 16-17).

However, our understanding is that it does not apply to transmission rates and therefore cannot be a guide in the allocation of costs to transmission customers. Therefore, we recommend that BPA consider applying the Cost Assignment Principles in this proceeding to the allocation of EIM costs and benefits in this proceeding.

Q. If BPA were to consider these Cost Assignment Principles, how would that change the cost allocation?

A. The key principle to consider is the "additional revenue benefit." The principles recognize that one business line could incur costs that would generate quantifiable benefits for the other business line.[14] Principle 6 would assign costs based on each business unit's needs and the associated benefits from meeting those needs. But when benefits can be quantified, Principle 7 states that the costs associated with the program would be allocated based on each business line's percentage of quantifiable benefits compared to the total quantifiable benefits.

In the case of the EIM, BPA has consistently admitted that there are no quantifiable benefits for transmission customers.[15] Power customers, however, would see quantifiable benefits of as much as $29-34 million in additional annual net revenue.[16] Accordingly, the benefits of BPA joining the EIM can be quantified, and applying the Cost Assignment Principles would result in the Power function being assigned most of the costs of joining the EIM, given the

[14] Cost Assignment Principles at 5 (see attached BP-22-E-JP01-01-AT02 at 5).
[15] EIM ROD at 121; *see also* Mace *et al.*, BP-22-E-BPA-31 at 13-14.
[16] EIM ROD at 120.

lack of quantifiable benefits for transmission customers and the significant quantifiable benefits for power customers.

Q. Has BPA stated whether these Cost Assignment Principles are consistent with BPA's legal guidelines and the Tiered Rate Methodology?

A. Yes. BPA stated at the time that the non-wires Cost Assignment Principles were consistent with its statutory and contractual obligations.[17]

Q. What would be the result of applying the Cost Assignment Principles?

A. If BPA applies the Cost Assignment Principles, then both the costs of joining the EIM (included in Grid Mod) and many of the ongoing costs of participating in the EIM should be allocated to power customers.[18] At the very least, notwithstanding BPA's response to NI-BPA-30-20, it seems arbitrary for BPA to have developed the non-wires Cost Assignment Principles and then declined to consider them in connection with a non-wires solution.

Q. Are there any other problems associated with using different cost allocation principles for transmission rates than were used for power rates?

A. In the generation inputs context, failing to allocate EIM costs to power rates in accordance with Principle 4 on equitable allocation results in an allocation of costs between Federal and non-Federal users of the system that, according to our understanding, is not equitable or comparable. In addition to supporting BPA's Power function, BPA's generation assets support its transmission system and are instrumental in maintaining reliability. The uses of the generating capacity

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[17] Cost Assignment Principles at 2 (see attached BP-22-E-JP01-01-AT02 at 2).

[18] *See* Section 4 of this testimony regarding the allocation of Grid Mod costs.

available to BPA to support the transmission system and maintain reliability are generally referred to as "generation inputs."[19] For ratemaking purposes, the Transmission function's uses of generation inputs are quantified and the costs associated with these uses are allocated to transmission rates (specifically, to ACS rates) under the ratemaking principle of cost causation. In short, BPA's Power function calculates both the quantity and cost of capacity needed to support BPA Transmission's need for generation and then Transmission allocates those costs among transmission customers. But there does not appear to be any subsequent analysis by BPA of whether the proposed generation inputs rates result in an equitable allocation of costs between Federal and non-Federal users of the system. That analysis certainly does not appear in BPA's testimony related to the Balancing Reserve Capacity Forecast (BP-22-E-BPA-24) or the Capacity Cost Methodology (BP-22-E-BPA-25). Regardless of which cost allocation principles BPA used, BPA should have conducted such an analysis.

Q. In your view, do the proposed generation inputs rates represent an equitable allocation of costs between Federal and non-Federal users of the transmission system?

A. No, our understanding is that they do not, especially under the allocations proposed for BPA's participation in the EIM. As noted above, "generation inputs" is a set of costs of the Federal generation system that is passed through to transmission rates. BPA has articulated a comprehensive mechanism to allocate

[19] Generation Inputs Study, BP-22-E-BPA-06 at 1.

the costs of joining and participating in the EIM to customers based on cost causation principles.

For revenues from the EIM, however, BPA proposes to allocate all EIM revenues to either the composite cost pool or the non-Slice cost pool, both of which are designed to allocate power costs between BPA's Slice and non-Slice customers. Those EIM revenues will therefore function as a credit to offset the costs of the Federal generation system that BPA must recover from its power customers.

At this point, it is important to acknowledge that BPA's power customers are also transmission customers. Accordingly, power customers also pay their share of generation inputs costs through their transmission rates. For example, loads pay their share of the capacity used for balancing services. But BPA proposes to allocate *all* EIM revenues to either the composite cost pool or the non-Slice cost pool; in either case, such allocation benefits only Federal users of the system. The effect is to create a subsidy from significant secondary revenues, which is shared only among a subset of customers, while all transmission customers share in the costs of the EIM.

Q. Please explain how this works.

A. To participate fully in the EIM, BPA must demonstrate that its Balancing Authority Area ("BAA") has sufficient resources to meet its reliability obligations. In order to make sure that EIM participants do not lean on the capacity and flexible capacity of other market participants, the California Independent System Operator ("CAISO") requires BAAs in the EIM to pass three resource sufficiency screens: a balancing test, a capacity screen, and a flexible ramping capacity screen. BPA intends to use the quantity of balancing reserve capacity established in the generation inputs process to pass the CAISO resource sufficiency screens. BPA has estimated that the balancing reserve capacity requirement defined in the rate case methodology will allow it to pass these tests 90% of the time. Even though the quantity of BPA's generation capacity charged to transmission customers' ACS rates is based on BPA's reliability obligations, when BPA joins the EIM, that capacity may generate significant revenues. BPA conservatively estimates that these revenues may grow to $30-40 million per year. Effectively, BPA proposes to charge all of its transmission customers for capacity needed to support the reliability of the system. BPA will then use that capacity to generate additional revenues, but only share those revenues with a subset of the customers who pay the underlying costs.

Q. What is your recommendation?

A. BPA should apply the Cost Assignment Principles in allocating the costs and the benefits associated with the EIM, as these principles were developed precisely for situations in which the costs of a program are distributed differently than the benefits associated with the program. The Cost Assignment Principles specifically contemplate that BPA staff will consider cost assignment based on each business unit's needs and the associated benefits received from meeting those needs. More specifically, BPA contemplated a Cost Assignment Principle that costs would be assigned based on an "additional revenue benefit."[20]

[20] Cost Assignment Principles (see attached BP-22-E-JP01-01-AT02 at 1-7).

> This would include any estimates of additional revenue from transmission sales, secondary energy sales, and sales of capacity-related services (such as ancillary services, Resource Support Services, and peak load service). Additional revenue benefits will take into account business unit revenue credits (such as generation inputs provided to transmission by power).[21]

In our view, BPA's failure to consider the Cost Assignment Principles—especially an additional revenue benefit—is arbitrary and capricious. These principles were developed and discussed with customers precisely because of concerns that non-wires programs like the EIM could result in costs being borne by one set of customers while benefits flowed to a different set of customers.

Our understanding is that BPA's proposal to allocate all EIM revenues in a manner that only benefits Federal users of the system would also result in an inequitable allocation of costs and benefits that is inconsistent with comparability principles. Non-Federal users of the system who are allocated generation inputs costs would not receive any value for BPA's use of that generation inputs capacity to generate incremental EIM revenues. Federal users of the system (who also pay for generation inputs capacity), however, would benefit from a significant increase in secondary sales revenue from EIM transactions; such revenue from EIM transactions would yield a significant reduction in the Federal users' power rates. Under BPA's current proposal, only non-Federal generation in BPA's BAA would be allocated EIM costs without being allocated the attendant benefits, and would therefore be treated inequitably in our view. The

[21] *Id.*

effect of BPA's proposal is to create a mechanism where transmission customers pay the costs of resources that only generate benefits for power customers.

Q. Do you have any recommendations that would eliminate this inequity?

A. Yes. The best way to eliminate this unjust and inequitable subsidy would be to provide transmission customers with a credit from BPA's EIM revenues. For each hour, all transmission customers would receive a credit up to the value of the capacity costs in their ACS rates. This credit would come from revenues BPA receives from EIM transactions and would appear on a customer's monthly invoice. Only in hours where EIM revenues exceed the costs associated with transmission customers' ACS rates would any surplus revenues flow into the composite cost pool.

Q. Is there a different alternative to BPA's proposal and the one you posed above that would also result in a more equitable allocation of EIM revenue?

A. Yes. The mechanism above would directly reimburse generation inputs customers for the capacity costs they pay that enable participation in the EIM. In BP-22-E-BPA-33 at 12-14, BPA is proposing to proportionately allocate EIM revenue to the composite cost pool and the non-Slice cost pool. The proportional amount allocated to the composite cost pool would be the amount of non-regulation balancing capacity offered in that hour divided by the total amount capacity offered to the EIM in that same hour (the "Pro Rata Share"). BPA's rationale for this allocation is that non-regulation balancing capacity is a Designated System Obligation for Slice customers; BPA proposes to allocate a portion of EIM revenue to the composite cost pool as the mechanism to allocate the appropriate share of EIM revenue to Slice customers. In other words, BPA already has a proposal on how to allocate EIM revenue associated with non-regulation balancing capacity; however, BPA would allocate these EIM revenues only to Federal users of the system, not to all the customers who pay generation inputs rates.

Rather than allocating the Pro Rata Share to the composite cost pool, we suggest that it would be more appropriate to allocate the Pro Rata Share to all generation inputs customers as a monthly credit. Thus, the credit would be applied to transmission rates where it would be shared by all transmission customers (including BPA's power customers) who contribute to the costs of capacity upon which BPA's EIM participation depends. In our view, this would result in a more comparable and equitable allocation of costs and benefits between Federal and non-Federal users of the system.

Q. Does your analysis—together with the accompanying recommendations—depend on BPA applying the Cost Assignment Principles?

A. No. We believe that the alternatives described above to credit all customers who pay generation inputs rates for the value of the capacity they pay reflect more equitable allocations under either the Cost Assignment Principles or under the cost allocation principles BPA proposes to apply. Thus, even if BPA declines to apply the Cost Assignment Principles in this proceeding, BPA should consider adopting our crediting proposals.

Section 2.2 Overcollection of Opportunity Costs

Q. Have you identified any other issues with BPA's proposed allocation of costs when it joins the EIM?

A. Yes, it appears that under the Initial Proposal, BPA will overcollect revenues associated with its opportunity costs, which according to our understanding, could result in BPA collecting rates in excess of its total system costs.

Q. Please explain.

A. BPA calculates the cost of the capacity for generation inputs by adding two components: an embedded cost component and a variable cost component.[22] "The embedded costs component accounts for the fixed cost of the Federal system."[23] The variable cost component includes costs associated with what BPA's Initial Proposal describes as "efficiency losses."[24] As part of the methodology to generate the cost of generation inputs, BPA calculates the variable costs associated with holding generation capacity available for use by transmission customers.

> When BPA holds capacity, it incurs variable costs due to efficiency losses. Efficiency losses are impacts to the Federal [hydro] system in regard to output in MWs, timing of energy generated and revenues received. . . . These efficiency costs are determined by measuring the difference between: (1) the costs of operating the Federal system at an optimal efficient level *without* holding capacity reserves; and (2) the cost of operating the Federal system at an optimal level *with* holding capacity reserves. The difference between those costs are generally referred to as variable costs.[25]

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[22] Generation Inputs Study, BP-22-E-BPA-06 at 31.
[23] *Id.*
[24] *Id.* at 38.
[25] *Id.*

Among the variable costs BPA passes through to its generation inputs customers are the "Stand-Ready Costs" described in Section 4.3 of the Generation Inputs Study.[26] These specific costs include energy shift, efficiency loss, and spill losses. The energy shift costs determine the cost to BPA that result when – in order to provide reserves – BPA shifts generation production from an hour with a higher price to an hour with a lower price.[27] The total cost of "energy shift" is over $14 million per year.[28] In describing its Variable Cost Pricing Methodology, BPA indicates:

> The variable cost pricing methodology quantifies the energy impact of holding capacity reserves and allocates that energy cost to those services. This effectively results in allocating a portion of BPA's costs that were classified as energy to BPA's capacity reserve services. . .. [C]apacity reserve services impact energy by changing efficiency, shifting when the energy available, or even causing fuel (water) to be spilled. . .. [T]he variable cost pricing methodology calculates the decrease in energy revenue that is caused by holding reserve capacity. Because the Federal system holds reserves, it reduces BPA's energy revenue that would otherwise be used to recover costs classified as energy costs.[29]

This analysis was accurate in the past because BPA had to set capacity aside to meet the potential need for reserves and was not able to offer that potential energy to the market. In joining the EIM, however, BPA now actually has a mechanism to monetize that capacity effectively.

Q. How can BPA monetize that capacity via the EIM?

A. When participating in the EIM, the market operator automatically sends market awards that result in dispatches of generation that has been bid into the

[26] *Id.* at 44.
[27] *Id.* at 45.
[28] *Id.* at 46.
[29] Ramse *et al.*, BP-22-E-BPA-25 at 14.

market. BPA's current expectation is that it will offer the full amount of its non-regulation balancing reserves to the EIM in most – if not all – hours. BPA notes that there may be operationally sensitive periods of time where BPA may choose to classify the non-regulation reserves (or some portion of the non-regulation reserves) as "Available Balancing Capacity" ("ABC") rather than bid that capacity into the market. But designating capacity as ABC will limit the deployment of that capacity only to imbalances within the BPA BAA (as opposed to the EIM footprint as a whole), and only in specific instances (such as if BPA faced a Power Balance Constraint, which represents the inability of the EIM optimization to dispatch the appropriate level of generation to meet load in the BAA).[30] For the most part, the non-regulation balancing reserve capacity that is set aside (and paid for by generation inputs customers) is available for dispatch across the EIM footprint (unless it is designated ABC, in which case it is still available for dispatch within BPA's BAA). But the balancing reserve capacity – at least the non-regulation reserve capacity – can now be bid and the energy monetized.

Q. That seems to be more an argument that BPA should not include variable costs in calculating its generation inputs rates; how will BPA overcollect those variable costs?

A. In weighing whether to participate in the EIM, BPA has consistently pointed out that the EIM bidding structures do not reflect the unique characteristics of an energy-limited hydro system like BPA's. BPA's comments to CAISO indicate

[30] BPA Response, NI-BPA-30-36.

BPA's support for proposed changes to CAISO's market power mitigation rules, which would allow a new default energy bid option to enable hydro resources (like BPA's) to reflect their opportunity costs in the bids into the EIM.[31] Among the opportunity costs BPA hoped to include in structuring its bids for the EIM were the value of foregone sales in:

(1) a different geographic location during the same period;

(2) the same geographic location in a future period; or

(3) a different geographic location in a future period.[32]

In its filing with the Federal Energy Regulatory Commission ("FERC") for approval of the changes to its market power mitigation program sought by BPA, CAISO explained the changes this way:

> The proposed hydro [Default Energy Bid] has three components: Long-Term/Geographic, Short-Term, and the Gas Floor. These three components respectively represent (1) opportunity costs created by the potential to sell a hydroelectric resource's limited energy production in the future, including in different bilateral markets; (2) short-term opportunity costs created by short-term water use limitations; and (3) the potential cost of replacement energy in the real-time market if the resource exceeds its short-term limitations.[33]

These opportunity costs that can be recovered in the EIM (an energy market) are the same as the components of the variable cost pricing methodology component of the capacity costs charged to generation inputs customers. In its filing, CAISO

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[31] BPA, CAISO LOCAL MARKET POWER MITIGATION ENHANCEMENTS DRAFT FINAL PROPOSAL (UPDATED), FEBRUARY 1, 2019, BONNEVILLE POWER ADMINISTRATION COMMENTS (2019) (see attached BP-22-E-JP01-01-AT02 at 8-10).

[32] *Id.* at 2.

[33] *CAISO Tariff Amendments to Enhance Local Market Power Mitigation and Reflect Hydroelectric Resource Opportunity Costs in Default Energy Bids*, Docket No. ER19-2347-000 at 32 (July 2, 2019) (see attached BP-22-E-JP01-01-AT02 at 16).

went on to note the importance of allowing default energy bids to capture a hydro system's opportunity costs:

> Accuracy of default energy bids reflecting opportunity costs are important anytime a resource's energy bid is mitigated to its default energy bid. If a default energy bid is lower than opportunity costs, it can cause a resource with limited availability to run inefficiently, or earlier [or later] than at optimal times. This in turn could result in reducing energy available to markets, or worse not offering any energy into the market and reducing overall market capability and efficiency.[34]

In short, BPA successfully requested that CAISO allow hydro systems to recover their opportunity costs (including efficiency losses and energy-shift losses) in BPA's bids into the EIM. Furthermore, BPA clearly intends to include opportunity costs in its energy bids to the EIM.[35]

Q. Is there another way BPA will collect those opportunity costs or variable costs twice?

A. In addition to the capacity costs for balancing reserves discussed above, BPA also charges customers for energy when it deploys reserves on their behalf. In the past, these energy charges were recovered through Generator Imbalance (for generation connected to BPA's system) or Energy Imbalance (for BPA's load customers). Going forward, however, BPA intends to settle energy deployed for balancing services at the Locational Marginal Price ("LMP").[36] BPA accurately describes the operation of the EIM and settlement of EIM charges in BP-22-E-

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[34] *Id.* at 33 (see attached BP-22-E-JP01-01-AT02 at 17).

[35] Our expectation is that power providers will offer available energy to the EIM at their marginal cost of providing that energy (at the higher of the provider's production and opportunity cost). *See* BPA Response, PS-BPA-30-3 (see attached BP-22-E-JP01-01-AT01 at 1); *see also* BPA Response, PS-BPA-30-4.

[36] Mantifel *et al*., BP-22-E-BPA-30 at 3.

BPA-30. The most important change for the purpose of this section of our testimony is the pricing of imbalance energy. In the past, BPA settled imbalance energy at an index price and collected those charges directly from customers. Once BPA joins the EIM, BPA proposes to settle imbalance energy at the CAISO-derived LMP.[37] BPA will collect those costs once from its generation inputs customers. BPA will collect those opportunity costs again through the EIM when the capacity which BPA bids into the EIM is dispatched. If a generation inputs customer incurs imbalance (either Generator Imbalance or Energy Imbalance), it will compensate BPA twice for BPA's opportunity costs. To the extent that BPA's EIM bids are accepted and CAISO dispatches BPA generation to serve imbalance in neighboring BAAs, BPA would collect its opportunity costs there as well, and be compensated twice for its opportunity costs (once in the capacity rates its charges transmission customers and again from the CAISO settlement process). By being compensated more than once for the same set of costs, our understanding is that BPA would be charging rates in excess of its total system costs.

Q. Did BPA make any changes in how it estimates these variable costs that reflect EIM participation?

A. BPA indicated that it did not make any changes in process, assumptions, or code in the Generation and Reserves Dispatch ("GARD") model to reflect EIM participation other than to move from three cost buckets to two cost buckets.[38]

[37] *Id.* at 8.

[38] BPA Response, NI-BPA-30-38 (see attached BP-22-E-JP01-01-AT01 at 3).

Q. How should BPA incorporate EIM participation into the estimate of these variable costs?

A. BPA should exclude all variable costs associated with non-Regulation capacity from the variable cost calculation shown on Table 4.8 of BP-22-E-BPA-06A. This should result in a more accurate estimate of variable costs incurred by holding generation inputs capacity.

Q. Do you have a recommendation to prevent BPA from this overcollection?

A. Yes, we recommend that BPA provide a credit to generation inputs customers when it earns revenues in the EIM. The credit should be designed to reimburse transmission customers who pay for capacity that BPA bids into the EIM. Only in time intervals when BPA's EIM revenues exceed the cost of the underlying capacity paid for by BPA's generation inputs customers should any surplus revenues be allocated to the composite cost pool.

Q. Do you have any other observations related to this overcollection?

A. Yes. This overcollection can occur even when BPA settles imbalance energy at an index price. An index price reflects the weighted average of actual transactions between parties. BPA and other hydro generation owners are unlikely to make bilateral transactions that do not compensate them for the calculation of their opportunity costs. Accordingly, the index price itself will include transactions with an opportunity cost component, and using it to settle energy imbalance will also result in overcollection of those opportunity costs.

Section 3: BPA's Quantity Of Capacity For Balancing Service

Q. Please summarize this section of your testimony.

A. This section documents that BPA's proposed rates significantly overstate BPA's balancing reserve needs. First, we calculate the actual level of balancing reserves BPA needs to comply with the relevant NERC standard. Second, we explain the methodological errors that cause BPA to overstate the need for balancing reserves. In addition, we note how some of these errors not only cause BPA to overstate reserve needs, but also cause an excessive share of the balancing reserve obligation and cost to be allocated to VERs.

<u>Section 3.1: BPA's claimed balancing reserve need overstates its actual need</u>

Q. What does BPA claim is its need for balancing reserves?

A. BPA claims an *inc* balancing reserve need of 704.62 MW, and a *dec* balancing reserve need of 851.60 MW, in total across all regulating and non-regulating reserve categories for dispatchable generators, wind, solar, load, and federal hydro resources.[39]

Q. What is the actual balancing reserve need?

A. Our analysis indicates that BPA could still fully comply with NERC's BAL-001-2 standard,[40] which governs Real Power Balancing Control Performance, by holding about 78% less balancing reserves than BPA's claimed need. Specifically, we find the *inc* balancing reserve need to be 117.81 MW, and *dec* need to be 227.50 MW. These are 16.7% and 26.7% of BPA's claimed *inc* and *dec* balancing reserve needs, respectively.

Q. How did you determine the actual balancing reserve need?

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[39] Transmission Rates Study and Documentation, BP-22-E-BPA-08 at 189.

[40] NERC, STANDARD BAL-001-2 – REAL POWER BALANCING CONTROL PERFORMANCE (see attached BP-22-E-JP01-01-AT02 at 33-41).

A. First, we obtained data for BPA's Area Control Error[41] ("ACE") and balancing reserve deployments[42] for the 72-month period BPA used for its rate analysis, covering October 2013-September 2019. We subtracted balancing reserve deployments from the ACE to see what BPA's ACE would have been without the use of any balancing reserves. From there, we were able to reconstruct the actual level of balancing reserves BPA would have needed to comply with NERC Standard BAL-001-2.

Q. How did you reconstruct the level of balancing reserves needed to comply with BAL-001-2?

A. We recreated the formula for determining compliance with the BAL-001-2 standard.[43] Power system frequency[44] and BPA's frequency bias setting determine the ACE limit for each operating minute. As the NERC chart copied below shows,[45] BAL-001-2 specifies that a Balancing Authority ("BA") cannot allow ACE to exceed the positive ACE limit (shown in brown) for more than 30 minutes when frequency is above 60 Hz (Quadrant 1), or fall under the negative ACE limit (shown in red) for more than 30 minutes when frequency is below 60 Hz (Quadrant 3). The following chart is for a hypothetical 10,000 MW peak load BA in the Eastern Interconnect with a frequency bias setting of -100 MW/0.1 Hz,

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[41] Area Control Error measures a BA's supply and demand imbalance, after accounting for scheduled imports and exports. BPA Area Control Error (ACE) Annual Reports, Per FERC Order 784, BPA, https://transmission.bpa.gov/Business/Operations/ ACE_FERC784/ (last visited Feb. 2, 2021).

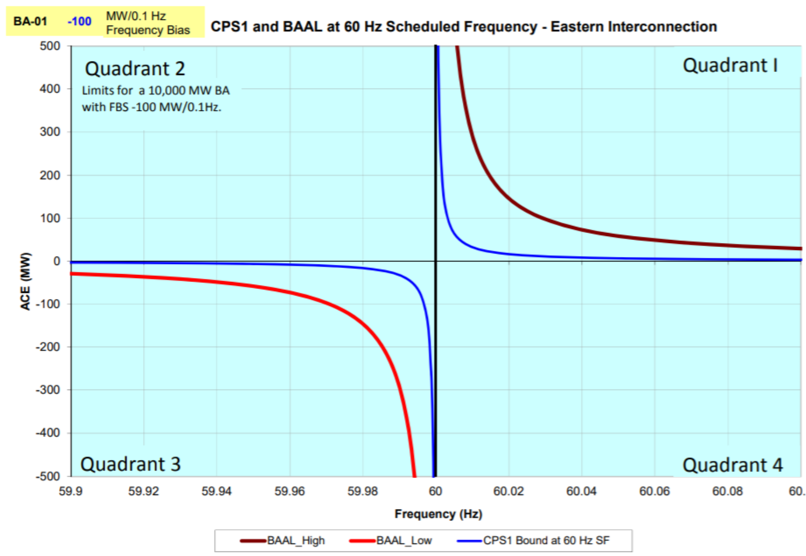
[42] Wind Generation & Total Load in The BPA Balancing Authority, BPA, https://transmission.bpa.gov/Business/Operations/Wind/ (last visited Feb. 2, 2021).

[43] *See* NERC, STANDARD BAL-001-2 – REAL POWER BALANCING CONTROL PERFORMANCE 8 (see attached BP-22-E-JP01-01-AT02 at 40.

[44] Frequency data at a one-minute time resolution was obtained in BPA Response, NI-BPA-30-22.

[45] *Informational Filing of NERC Interim Report on Balancing Authority ACE Limit Field Trial*, Docket No. RM14-10-000 at 24 (July 31, 2014).

though that is roughly the same size as BPA (10,243 MW, with a frequency bias setting of -139.9 MW/0.1 Hz).[46]



There is no ACE limit in the other two quadrants, because a positive ACE helps when Western Interconnect frequency is below 60 Hz (Quadrant 2), and negative ACE helps when Western Interconnect frequency is above 60 Hz (Quadrant 4). The ACE limit approaches infinity when power system frequency approaches the target of 60 Hz, and only becomes significantly limiting if frequency is far from 60 Hz, as shown in the chart. If at any point in the 30-minute period, ACE falls below the ACE limit, either because ACE was reduced or because frequency moved closer to 60 Hz, increasing the ACE limit, the clock restarts. Similarly, the clock restarts for any switch between positive and negative ACE, or between low and high frequency. Western Interconnect frequency almost always hovers right around 60 Hz. Frequency crossed 60 Hz in 86% of 30-minute intervals in a

46 NERC, BAL-003-1 FREQUENCY RESPONSE OBLIGATION ALLOCATION AND MINIMUM FREQUENCY BIAS SETTINGS FOR OPERATING YEAR 2020 5 (2020), https://www.nerc.com/comm/OC/Documents/BA%20FRO%20Allocations%20for%20OY2020.pdf.

sample year, and large persistent frequency deviations are rare. A BAL-001-2 violation thus requires a perfect storm of four rare factors to coincide:

1. Frequency is very high or very low
2. Frequency stays very high or very low for more than 30 minutes
3. A large ACE deviation occurs in the same direction, harming frequency
4. The large ACE deviation persists in the same direction for more than 30 minutes.

Q. How did you determine BPA's actual balancing reserve need based on the BAL-001-2 formula?

A. In the dataset we created representing BPA ACE in the hypothetical case with no balancing reserves, we found the minutes during each year of the 6-year test period that were the worst violation of the ACE limit under the BAL-001-2 standard. The maximum amount by which ACE exceeded the ACE limit for 30 minutes determines the amount of balancing reserves needed for BPA to be fully compliant with BAL-001-2 for that year.

Q. What were those balancing reserve needs?

A. The table below shows the balancing reserves needed to comply with the NERC BAL-001-2 standard in each of the six years of the analysis period. All of these reserve needs are much lower than the balancing reserve levels BPA claims it needs going forward.

	Inc Reserve need, MW	*Dec* Reserve need, MW
Oct 2013 - Sept 2014	323.35	-305.11
Oct 2014 - Sept 2015	269.87	-609.75
Oct 2015 - Sept 2016	346.11	-256.53
Oct 2016 - Sept 2017	92.15	-305.79

Oct 2017 - Sept 2018	179.80	-172.90
Oct 2018 - Sept 2019	117.81	-227.50

There appears to be a downward trend in balancing reserve needs over the 6-year period, likely caused by the adoption of BAL-001-2 and the migration of wind resources out of BPA's BAA over time. BAL-001-2 took effect on July 1, 2016,[47] and was expected to significantly reduce balancing reserve needs relative to the prior version of the standard, BAL-001-1.[48] BPA itself noted in May 2016 that moving to the BAL-001-2 standard was expected to reduce balancing reserve needs for wind generators by about 25%.[49] There was also a significant migration of wind capacity out of BPA's BAA in December 2017 and July 2018, bringing total wind capacity to 2,764 MW, down from the 4,515 to 4,782 MW that had been online from May 2012 until December 2017.[50] This large reduction in wind capacity likely somewhat reduced the need for balancing reserves.

Q. What does this indicate regarding BPA's need for balancing reserves going forward?

A. As noted above, only the last three years in the analysis (October 2016-September 2019) capture the transition to BAL-001-2 on July 1, 2016, and only the last year of the analysis captures the large migration of wind capacity out of BPA's BAA

[47] *Mandatory Standards Subject to Enforcement*, NERC, https://www.nerc.net/standards reports/standardssummary.aspx (last visited Feb. 3, 2021).

[48] *Real Power Balancing Control Performance Reliability Standard*, 151 FERC ¶ 61,048 (Apr. 16, 2015).

[49] BPA, Generation Inputs Workshop at 13 (May 24, 2016) (see attached BP-22-E-JP01-01-AT02 at 54).

[50] BPA, WIND GENERATION NAMEPLATE CAPACITY IN THE BPA BALANCING AUTHORITY AREA (2020), https://transmission.bpa.gov/business/operations/Wind/WIND_InstalledCapacity _Plot.pdf .

in July 2018. The 2,764 MW of wind capacity online after July 2018 most closely aligns with the average of 3,028 MW of wind BPA expects to be online during the rate period.[51] As a result, the balancing reserve needs for October 2018-September 2019 are the most indicative of balancing reserve needs going forward.

Q. How do those results compare to BPA's claimed reserve need?

A. Those results are much lower than BPA's claimed need. The maximum *inc* reserve need in October 2018-September 2019 was 117.81 MW, while the maximum *dec* need was 227.50 MW. These are 16.7% and 26.7%, respectively, of BPA's claimed total balancing reserve needs of 704.62 MW *inc* and 851.60 MW *dec* across all reserve types.

Notably, BPA's claimed results are for average reserve needs across an entire year, while our results indicate the maximum reserve need in any of the 525,600 30-minute periods over the course of a year. Because it is exceedingly rare that large amounts of balancing reserves are needed to comply with BAL-001-2, the average reserve need is much lower than the maximum need.

Q. Why are these results so much lower than BPA's claimed need?

A. The methodological errors that caused BPA to overstate balancing reserve needs are discussed in detail in the next section of our testimony.

Q. Has the method you outlined above been used in other rate cases?

A. Yes, a similar methodology was introduced by PacifiCorp in a VER balancing reserve rate case that was approved by FERC. PacifiCorp statistically calculated

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51 Puyleart *et al.*, BP-22-E-BPA-24 at 11.

the probability of its actual ACE exceeding BAL-001-2's specified limit, as shown in Figure 8 of its Regulation Reserve Study.[52] PacifiCorp notes that schedule changes and frequency changes brought ACE below the ACE limit in the vast majority of 30-minute periods, reducing balancing reserve needs.[53]

More recently, Mr. Goggin conducted analysis using the method described above for a FERC rate case brought by NorthWestern Energy that included VER balancing reserve rates.[54] This methodology was well-received by other parties including FERC trial staff, and was instrumental in driving a roughly 70% reduction in the settled VER balancing reserve rate relative to what NorthWestern had proposed.

Q. Were any periods excluded from your analysis?

A. Yes. BPA's balancing reserve data for the year 2015 was missing data for the day December 31, 2015.[55] To fill in the missing data, balancing reserve deployment was assumed to be 0 MW for that day. It does not appear that this affected the results, as there did not appear to be any events that were likely to result in an ACE limit violation that day.

There also appears to have been an anomaly in the data on the afternoon of March 18, 2017. The data appears to show *inc* reserve deployment going as high as 2,661 MW that afternoon, nearly three times the 900 MW *inc* reserve maximum limit reported by BPA for that period, and much higher than the

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[52] *PacifiCorp*, Revisions to Open Access Transmission Tariff, Docket No. ER17-219, PAC-14 at 21 (Oct. 28, 2016).

[53] *Id.*at PAC-13 at 28; *see also* Docket No. ER19-1756.

[54] *See NorthWestern Corporation*, Docket No. ER19-1756.

[55] BPA, DATA FOR BPA BALANCING RESERVES DEPLOYED (2015), https://transmission.bpa.gov/Business/Operations/Wind/ReservesDeployedYTD_2015.xls.

maximum deployment across the remainder of the 6-year period in BPA's data.[56] It appears that the *inc* reserve deployment indicated in the data coincided with a large curtailment of wind generation due to oversupply mitigation and Operational Controls for Balancing Reserves ("OCBR") limits. Subtracting the very large *inc* reserve deployment from the ACE for the purpose of reconstructing what ACE would have been without balancing reserves causes the appearance of a very large and persistent negative ACE, which drives the model to show a very large need for *inc* reserves for that period.

However, it would be unreasonable to conclude that this event indicates a large need for *inc* reserves, because 1) BPA would not have been curtailing wind generation due to oversupply mitigation and OCBR limits if BPA were truly running a large negative ACE, and 2) even if there were a large need for *inc* reserves, BPA could have used curtailed wind generation to provide the *inc* reserves by lessening the curtailment and dispatching the wind output up, and thus would not have needed other resources to provide *inc* reserves. Other grid operators use curtailed wind resources to provide *inc* balancing reserves in this way.[57] As a result, to address this anomaly for modeling purposes, *inc* reserve deployments were assumed to be 900 MW for that afternoon, which prevented any ACE limit violations from occurring that afternoon.

Q. Does this analysis of balancing reserve needs account for forecast error, or does it assume perfect foresight?

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56 BPA, DATA FOR BPA BALANCING RESERVES DEPLOYED (2017), https://transmission.bpa.gov/Business/Operations/Wind/ReservesDeployedYTD_2017.xls.

57 E. ELA ET AL., NREL, ACTIVE POWER CONTROLS FROM WIND POWER: BRIDGING THE GAPS 93 (2014).

A. This analysis accounts for forecast error and does not assume perfect foresight. This analysis is based on the actual ACE deviations that BPA experienced. ACE deviations occur when VERs, load, or conventional generation deviate from their schedules. Thus, the calculation of the balancing reserve need is based on the actual level of forecast error that BPA experienced during the 6-year analysis period. As a result, the analysis accurately measures the amount of balancing reserves BPA needed to fully comply with BAL-001-2.

Section 3.2: Errors that cause BPA to overstate reserve needs and bias the reserve allocation against VERs

Q. What errors caused BPA to overstate balancing reserve needs?

A. First, BPA's calculation of reserve needs rests on the arbitrary assumption that sufficient reserves must be held to account for 99.7% of calculated reserve needs.[58] A statistical approach like that made sense for modeling reserve needs under NERC's BAL-001-1 Standard, the predecessor to BAL-001-2. This is because under that standard, BAs were required to keep ACE within the requirement 90% of the time.[59] BAL-001-2, which replaced BAL-001-1 in July 2016, does not use a statistical approach to determining compliance, and instead requires compliance 100% of the time.

In exchange for that more stringent requirement, BAL-001-2 provides far more leeway by allowing ACE deviations that are not harmful to power system

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[58] *See* Puyleart *et al.*, BP-22-E-BPA-24 at 5 ("The Balancing Reserve Capacity Business Practice establishes the use of a 99.7 percent planning standard, meaning the forecast of reserve capacity encompasses 99.7 percent of all modeled reserve need within the study by discarding the 0.15 percent greatest *inc* values and the 0.15 percent greatest *dec* values.").

[59] NERC, STANDARD BAL-001-1 — REAL POWER BALANCING CONTROL PERFORMANCE 1, https://www.nerc.com/files/BAL-001-1.pdf

frequency or have a duration of less than 30 minutes. As noted above, there is no limit on helpful ACE deviations, ACE limits are extremely high when frequency is close to 60 Hz, and the 30-minute clock restarts any time frequency crosses 60 Hz or ACE crosses 0. Furthermore, BPA is no longer required to return ACE to zero, as had been the case under BAL-001-1. Under BAL-001-2, BPA is compliant as long as ACE falls below the ACE limit, which in almost all 30-minute periods never falls below several hundred MW. As a result, the vast majority of 30-minute intervals in a year are not subject to stringent ACE limits. As BPA itself has noted, "BAL-001-2 introduces a more lenient limit when frequency is not significantly deviating."[60] BPA further explained that "BAL-001-2 has the potential to reduce the Balancing Reserve Capacity Quantity Forecast while maintaining the level of reliability, due to the more lenient limit imposed. Rather than deploying an amount of reserves necessary to drive ACE back to 0, we need to deploy enough reserves to correct ACE reliably inside the [Balancing Authority ACE Limit]." However, BPA continues to base its reserve needs on the arbitrary 99.7% assumption that was used before the transition to BAL-001-2 in July 2016, despite the fact that in May 2016, BPA had noted the new standard was expected to reduce wind reserve needs by 25%.[61]

BPA's exclusion of only the 0.15% highest *inc* and 0.15% highest *dec* reserve needs underestimates the share of ACE deviations that are permissible under BAL-001-2 because most of those deviations do not violate ACE limits for

60 BPA, Generation Inputs Workshop at 5 (Feb. 17, 2016) (see attached BP-22-E-JP01-AT02 at 69).
61 BPA, Generation Inputs Workshop at 13 (May 24, 2016) (see attached BP-22-E-JP01-AT02 at 54).

more than 30 minutes. BPA has presented no evidence or analysis to demonstrate that holding enough reserves to cover 99.7% of events is an adequate proxy for the requirements of BAL-001-2. Instead, BPA simply points to its own business practice to justify the 99.7% assumption, and that business practice refers to the 99.7% assumption as “a rule of thumb” and “a conventional heuristic.”[62] BPA has not provided adequate support for its 99.7% assumption, which results in excess reserve needs and costs that appear to discriminate against VERs.

Q. Did other errors affect BPA’s calculation of balancing reserve needs and its allocation of reserve costs to VERs?

A. Yes. BPA missed several factors that are reducing the variability of wind and solar resources over time. These errors not only cause BPA to overstate its total balancing reserve needs, but also cause it to assign an excessive share of balancing reserve costs to VERs relative to other customer classes.

Q. Did BPA account for improvements in wind forecast accuracy over time?

A. No. BPA notes that it assumed wind forecast accuracy was “relatively stable” over the 72-month analysis period, so future wind forecast accuracy was assumed to be the same as it was over the October 2013-September 2019 analysis period.[63] As a result, BPA’s assumed wind forecast accuracy for the FY 2022-23 rate period will be based on actual wind forecast accuracy nearly a decade earlier. This misses significant improvements in wind forecast accuracy that have already

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62 BPA, BALANCING RESERVE CAPACITY: BPA TRANSMISSION BUSINESS PRACTICE 2, n. 1 (2019), https://www.bpa.gov/transmission/Doing%20Business/bp/tbp/Balancing-Reserve-Capacity-BP.pdf

63 Puyleart *et al.*, BP-22-E-BPA-24 at 15.

occurred in the region,[64] as well as additional improvements that can be expected going forward. Forecasts are improving with advances in computing and sensor technology, and as experts learn better methods for forecasting wind output. The neural network models used for wind forecasting also improve simply by "learning" over time, as new weather events provide a larger dataset for them to infer the relationship between meteorological conditions and wind output patterns. Because balancing reserve needs are heavily driven by wind forecast errors, ignoring these wind forecasting improvements causes BPA to significantly overstate balancing reserve needs and the allocation of reserve costs to VER resources.

Q. Did BPA's analysis accurately account for periods in the dataset when wind resources were curtailed due to OCBR or oversupply limits?

A. No. BPA explains that, for these periods, it replaced actual wind output data that included the effect of those curtailments with estimated wind output. However, BPA also admits that it plans to continue using OCBR and oversupply curtailment during the rate period.[65] As a result, the actual output data is likely to more accurately reflect future wind output patterns, as both are affected by those curtailments. While we agree with the logic that wind plants should not be penalized for deviations from scheduled output that were caused by BPA curtailments, it is likely that during other periods, BPA curtailments bring wind output more in line with scheduled output. In particular, OCBR curtailments are

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64 *See, e.g.*, CAROLINE DRAXL et al., NREL, THE VERIFICATION AND VALIDATION STRATEGY WITHIN THE SECOND WIND FORECAST IMPROVEMENT PROJECT (WFIP 2) (2019) (see attached BP-22-E-JP01-01-AT02 at 87-111).

65 BPA Response,NI-BPA-30-28 (see attached BP-22-E-JP01-01-AT01 at 13).

designed to bring wind output in line with scheduled output,[66] and thus should almost always reduce wind's deviations from scheduled output. Because BPA admits it will continue using OCBR curtailments during the rate period, including the impact of OCBR curtailments in the historical dataset will more accurately predict wind output patterns going forward. By ignoring the beneficial impact of OCBR curtailments, BPA imposes a double penalty on wind generators, as the generators incur the cost of those curtailments without receiving any of the benefit from reducing balancing reserve needs.

Q. How did BPA model the variability of expected future wind resources?

A. As noted above, BPA expects an average of 3,028 MW of wind to be online during the rate period, 264 MW more than the 2,764 MW of wind capacity online currently. To model this roughly 10% increase in wind capacity, BPA simply assumed that the output profiles of future wind plants were identical to those of existing wind plants, but with a time lag.[67]

Q. Is BPA's assumption that a future wind plant's output is perfectly correlated with that of an upwind plant correct?

A. No. BPA's assumption overstates the correlation between the output of two wind plants, and thus understates the reduction in total wind fleet variability from adding new geographically diverse wind resources. The National Renewable

[66] *Operational Controls for Balancing Reserves*, BPA, https://www.bpa.gov/Projects /Initiatives/ Wind /Pages/operational-controls.aspx (last visited Feb. 3, 2021).

[67] BPA Response to NI-BPA-30-24 (see attached BP-22-E-JP01-01-AT01 at 12).

Energy Laboratory ("NREL") has even identified this as one of the most common errors in renewable integration analysis.[68] As NREL explains:

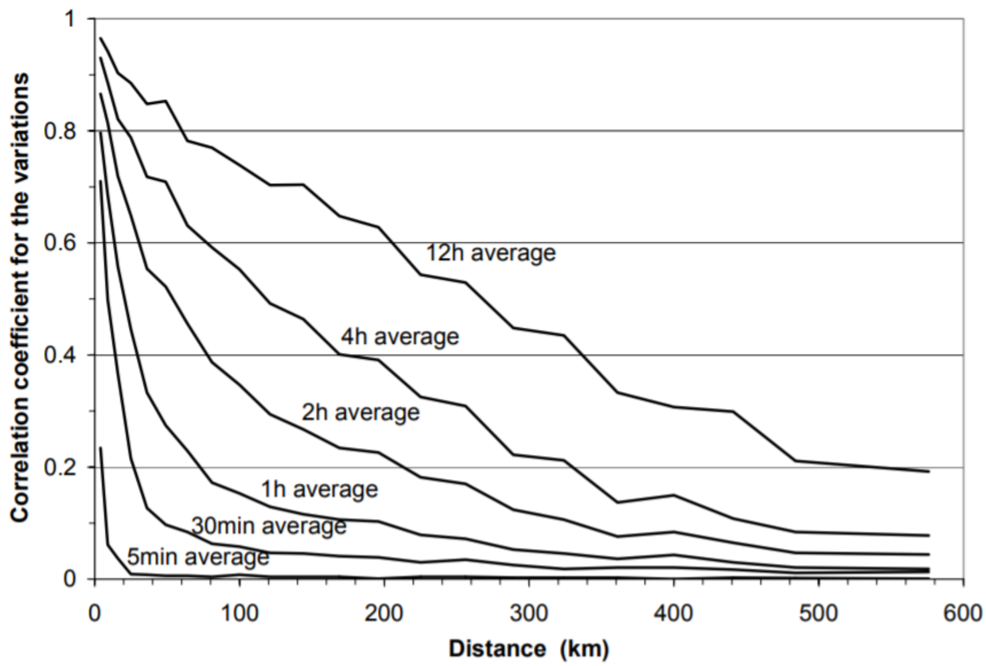
> A common error is to scale the output of an existing generator to represent the expected output of a larger fleet. This greatly overstates the variability of wind and likely overstates the variability of solar… It is similarly inappropriate to simulate a new wind plant simply by time delaying or advancing the output of an existing plant based on prevailing wind speed and direction. Wind does not remain coherent over inter-plant distances, so the resulting simulation will have too much correlation and too much variability.[69]

This scaling error causes BPA to overstate its total balancing reserve needs, and also biases the reserve allocation against VERs. The output of any two wind plants is always less than perfectly correlated. Even two wind plants located several dozen miles from each other have very low correlation in the sub-hourly output variability that is relevant for determining balancing reserve needs. As shown below, 50 miles (approximately 80 kilometers) is sufficient to reduce two wind plants' hourly variability correlation to less than 0.2.[70] While some of this lack of correlation is caused by the movement of weather systems over time, which is captured by BPA's time lag function, much of the lack of correlation is due to other meteorological factors that cause weather systems to evolve over time and affect two wind plants differently.

[68] M. MILLIGAN et al., NREL, COST-CAUSATION AND INTEGRATION COST ANALYSIS FOR VARIABLE GENERATION 27-28(2011).

[69] *Id.* at 27.

[70] H. HOLTTINEN et al., DESIGN AND OPERATION OF POWER SYSTEMS WITH LARGE AMOUNTS OF WIND POWER: FINAL REPORT, IEA WIND TASK 25, PHASE ONE 2006-2008 25 (2009).



As NREL notes, the atmosphere is a complex three-dimensional system that interacts with other systems, including ocean currents and the surface of the earth, not a one-dimensional system where winds always move at the same speed in one direction like BPA assumes. For example, higher-level winds, which generally move at higher speeds and may move in different directions from lower-level winds, interact with and affect the speed and direction of lower-level winds between the time they pass one wind plant and the time they reach another wind plant. Most wind is caused by the movement of high and low pressure systems, which cause wind speeds and directions to shift as they move. Heat and evaporation from the earth's surface, which fluctuates over the course of a day, drive convective meteorological events that can cause significant changes in wind speeds and direction between two wind plants. Wind's friction with the earth's surface, or even wake effects from existing wind plants,[71] can affect downwind wind plant output patterns.

At a minimum, prevailing wind directions vary over time. The topography of the Columbia Gorge and the Cascade Mountains introduce significant complexity that is not accounted for in BPA's one-dimensional assumption. For example, as the prevailing wind direction shifts, the wind shadow behind Mt. Hood and other topographical features can drastically affect some Pacific Northwest wind plants but not others. Due to these factors, BPA's simple time lag factor drastically overstates the correlation between the output of two wind plants, and thus understates the reduction in total wind fleet variability from adding new geographically diverse wind resources.

Q. Did BPA account for wind plant technology changes that may affect the output patterns of future wind plants?

A. No, even though technology has already significantly reduced the variability of modern wind plants relative to the older turbines that make up the majority of BPA's existing fleet. Multiple studies have documented that newer wind turbines, with longer blades and taller towers, have less variable output than older turbines, reducing the need for balancing reserves and the cost of integrating wind generation.[72] Larger turbines are able to access higher quality, more consistent

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[71] *See e.g.*, J. K. LUNDQUIST ET AL., NREL, COSTS AND CONSEQUENCES OF WIND TURBINE WAKE EFFECTS ARISING FROM UNCOORDINATED WIND ENERGY DEVELOPMENT (2018).

[72] *See, e.g.*, RYAN H. WISER ET AL., THE HIDDEN VALUE OF LARGE-ROTOR, TALL-TOWER WIND TURBINES IN THE UNITED STATES ELECTRICITY MARKETS & POLICY (2020); LION HIRTH & SIMON MULLER, ENERGY ECONOMICS, SYSTEM-FRIENDLY WIND POWER: HOW ADVANCED WIND TURBINE DESIGN CAN INCREASE THE ECONOMIC VALUE OF ELECTRICITY GENERATED THROUGH WIND POWER, Energy Economics(2016).

winds higher above the earth's surface. The increasing length of turbine blades has also caused the wind energy captured by turbines to increase much more quickly than the turbines' rated capacity, also driving more consistent output by disproportionately increasing output during periods of lower wind speeds.[73] Because BPA's modeling is based on a direct extrapolation from the existing fleet, the vast majority of which was installed between 2005 and 2013,[74] BPA effectively assumes that future wind installations will use technology that is a decade or two out of date. This causes BPA to overstate reserve needs, and also biases the reserve allocation against VERs.

In addition, BPA's use of output profiles from 2005-2013 vintage turbines ignores potential reductions in wind fleet variability due to the repowering of existing wind projects with modern turbines. Nationally, a large share of projects from the 2005-2013 vintage are being repowered to take advantage of improved technology and the ability to renew eligibility for the federal wind production tax credit; accordingly, BPA's output profile should take into consideration these national trends.

Q. Did BPA adequately account for reductions in balancing reserve needs due to EIM participation?

A. No. The primary benefit of the EIM is the diversity benefit of aggregating diverse sources of electricity demand and supply across the Western U.S. The variability

[73] RYAN H. WISER ET AL., BERKELEY LAB, WIND ENERGY TECHNOLOGY DATA UPDATE: 2020 EDITION 37 (2020).

[74] BPA, WIND GENERATION NAMEPLATE CAPACITY IN THE BPA BALANCING AUTHORITY AREA (2020), https://transmission.bpa.gov/business/operations/Wind/WIND_InstalledCapacity_Plot.pdf .

of wind,[75] solar,[76] and electricity demand[77] all significantly decrease when they are aggregated over a larger geographic area, as local fluctuations in the weather are canceled out by opposite fluctuations elsewhere in the West. The EIM allows a BA to exchange power with other participating BAs to net out those individual imbalances, rather than having to use balancing reserves to accommodate all variability. Over the last year, the diversity benefit of the EIM reduced participants' upward balancing reserve needs by about 46%, and downward reserve needs by about 49%.[78]

Q. How has that benefit changed over time?

A. This diversity benefit will tend to increase as more participants – including BPA – join the EIM, based on the fundamental statistical principle that larger aggregations of electricity supply and demand exhibit less variability and forecast error as a percent of total load.[79] The diversity benefit has increased over time as more BAs have joined the EIM, increasing from around 35% in 2016 and 2017 to nearly 47% today.[80]

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75 *See, e.g.*, MARK HANDSCHY ET AL., REDUCTION OF WIND POWER VARIABILITY THROUGH GEOGRAPHIC DIVERSITY (2016); H. HOLTTINEN et al., DESIGN AND OPERATION OF POWER SYSTEMS WITH LARGE AMOUNTS OF WIND POWER: FINAL REPORT, IEA WIND TASK 25, PHASE ONE 2006-2008 25 (2009).

76 ANDREW MILLS & RYAN WISER, BERKLEY LAB, IMPLICATIONS OF WIDE-AREA GEOGRAPHIC DIVERSITY FOR SHORT-TERM VARIABILITY OF SOLAR POWER (2010).

77 *Benefits*, WESTERN EIM, https://www.westerneim.com/Pages/About/Quarterly Benefits.aspx (last visited Feb. 3, 2021).

78 CAISO, WESTERN EIM BENEFITS REPORT: THIRD QUARTER 2020 (2020); CAISO, WESTERN EIM BENEFITS REPORT: SECOND QUARTER 2020 19-21 (2020).

79 *See, e.g.*, M. MILLIGAN ET AL., NREL, EXAMINATION OF POTENTIAL BENEFITS OF AN ENERGY IMBALANCE MARKET IN THE WESTERN INTERCONNECTION xiii (2013).

80 *Benefits*, WESTERN EIM, https://www.westerneim.com/Pages/About/Quarterly Benefits.aspx (last visited Feb. 3, 2021).

The diversity benefit may increase even faster going forward because the BAs slated to join in 2021 and 2022 are large and have very different resource portfolios and load patterns relative to the existing members. While the largest existing members are concentrated in the Southwest, which can cause less diversity in net load deviations due to correlated ramps in air conditioning demand and solar generation, the new members like BPA primarily come from Northwest and Mountain states. These new members have less exposure to air conditioning demand patterns and solar output patterns, while also increasing the impact of sources of variability like wind and hydropower output that are both uncorrelated on their own (i.e., wind output across the West shows little to no correlated movement or forecast error on a sub-hourly basis)[81] and weakly to negatively correlated with the sources of variability in the existing EIM members. As for the weak or negative correlation relative to existing EIM members, wind and solar tend to have negatively correlated output profiles on a diurnal basis, which can result in negative correlations at sub-hourly intervals, particularly in the morning and evening as wind and solar tend to ramp in opposite directions. Similarly, heating and air conditioning demand have opposite morning and evening ramps. These factors will tend to further increase the diversity benefit going forward.

Q. Does BPA account for the diversity benefit of EIM participation?

[81] H. HOLTTINEN et al., DESIGN AND OPERATION OF POWER SYSTEMS WITH LARGE AMOUNTS OF WIND POWER: FINAL REPORT, IEA WIND TASK 25, PHASE ONE 2006-2008 25 (2009).

A. No. BPA admits that it does not account for this diversity benefit, arguing that the EIM is an energy market that does not reduce the need for balancing reserve capacity.[82] This is inconsistent with EIM practice, as the entire purpose of the EIM is to allow BAs to net out supply and demand imbalances with other BAs instead of using their own balancing reserves.

Other grid operators have provided large reductions in balancing reserve needs and rates due to EIM participation. For example, in a 2017 FERC case, PacifiCorp provided a 38% reduction in balancing reserve needs due to EIM participation,[83] while in a FERC case settled in 2020, NorthWestern Energy agreed to a 48% reduction in the VER flexible reserve rate once it joins the EIM in April 2021.[84] BPA not only fails to account for the benefits of EIM participation, but also assumes that scheduling lead times must be moved even further in advance of the operating period for EIM participation, significantly increasing forecast error. As BPA notes, "[t]o reflect the EIM scheduling timelines, we used archived load forecast data produced an hour earlier than the load forecast data used in past rate cases."[85] Moving scheduling lead times farther in advance of the operating period has an even greater harm on VER forecast error. However, "BPA is proposing to eliminate scheduling elections" for VER resources due to EIM participation,[86] removing a valuable provision that

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[82] BPA Response, NI-BPA-30-31 (see attached BP-22-E-JP01-01-AT01 at 15); Puyleart *et al.*, BP-22-E-BPA-24 at 3.

[83] *PacifiCorp*, Revisions to Open Access Transmission Tariff, Docket No. ER17-219.

[84] *NorthWestern Corporation*, Docket No. ER19-1756.

[85] Puyleart *et al.*, BP-22-E-BPA-24 at 19-20; BPA Response to NI-BPA-30-30 (see attached BP-22-E-JP01-01-AT01 at 14).

[86] Puyleart *et al.*, BP-22-E-BPA-24 at 15.

had allowed VER resources to reduce their balancing reserve obligations by submitting 15-minute schedules to BPA. As noted above, this is inconsistent with EIM practice and intent, which allows BAs to respond more quickly to schedule deviations by netting those out with other BAs.

BPA turns EIM participation into a net harm for balancing reserve needs by ignoring the benefits of EIM participation while assuming it impairs efficient scheduling practices. In reality, VER resources significantly benefit from EIM participation due to the large reduction in sub-hourly wind and solar variability and forecast error across larger geographic areas. Thus, understating the EIM benefit not only causes BPA to overstate balancing reserve needs, but also biases the reserve allocation against VERs. As a result, BPA's methodology appears to discriminate against VERs.

Q. Do you have any other concerns with the proposed calculation of the generation inputs costs?

A. Yes, it is inappropriate to include BPA's capacity from power purchases in calculating the generation inputs costs. Generation inputs costs should be based on the capacity that BPA uses to meet its need for balancing reserve capacity to meet its system reliability obligations. BPA proposes to include all power purchases as an input in its generation inputs costs, including power purchased to serve load. There is no limitation on including capacity that can actually be dispatched for the purpose of providing balancing reserves.[87]

[87] Generation Inputs Study, BP-22-E-BPA-06 at 36.

Section 4: Functionalization of Grid Modernization Costs

Q. What is the Grid Modernization Program?

A. Grid Mod is a set of 35 separate projects spanning multiple rate periods. As BPA states: "[t]he goal of the Grid Modernization program is to position BPA to be competitive for future market opportunities as they arise, such as the Western Energy Imbalance Market, in addition to the other primary goals listed in our testimony, Mace *et al.*, BP- 22-E-BPA-31 at 2."[88]

Q. How has BPA proposed to allocate the costs of Grid Mod?

A. BPA proposes to allocate 65% of the Grid Mod costs to Transmission Services and 35% of the Grid Mod costs to Power Services.[89]

Q. Do you have concerns with this proposal?

A. Yes. Notwithstanding BPA's response to NI-BPA-30-20, we believe that BPA should have applied the aforementioned "Cost Assignment Principles Applicable for Acquisitions and Services That Benefit Both Power and Transmission Functions" to the allocation of Grid Mod costs. That document specifically contemplates that BPA staff will consider cost assignment based on each business unit's needs and the associated benefits received from meeting those needs. More specifically, BPA contemplated the principle that costs would be assigned based on an "additional revenue benefit."

> This would include any estimates of additional revenue from transmission sales, secondary energy sales, and sales of capacity-related services (such as ancillary services, Resource Support Services, and peak load service). Additional revenue benefits will

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[88] BPA Response, MS-BPA-30-142 (see attached BP-22-E-JP01-01-AT01 at 8).
[89] Mace *et al.*, BP-22-E-BPA-31 at 7-8.

> take into account business unit revenue credits (such as generation inputs provided to transmission by power).[90]

However, regardless of whether BPA applies the Cost Assignment Principles, BPA's functionalization method of cost allocation is flawed in that it ignores long-standing cost-causation principles—that customers who benefit from a program should bear the costs of that program.

Q. Please clarify whether transmission customers also receive benefits from Grid Mod and whether power customers pay a share of Grid Mod costs.

A. BPA has not quantified any additional revenue that Transmission would receive as a result of these Grid Mod projects. On the other hand, BPA has quantified significant additional revenues that Power will expect as a result of joining the EIM. Grid Mod projects related to EIM implementation are a significant portion of the Grid Mod portfolio.[91]

Q. BPA states that transmission customers receive significant qualitative benefits from EIM participation.

A. That is true, but note that all of BPA's power customers are also transmission customers. As transmission customers, BPA's power customers equally share the qualitative benefits of Grid Mod with all of those transmission customers of BPA who are not also power customers.

Q. BPA argues that a benefits functionalization approach that only considers Power Services' side of EIM-related power benefits is biased and flawed. How do you respond?

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90 Cost Assignment Principles at 5 (see attached BP-22-E-JP01-01-AT02 at 5).

91 BPA, GRID MODERNIZATION ROADMAP FY21 Q2, https://www.bpa.gov/Projects/Initiatives/Grid-Modernization/gridmod/Current-Grid-Mod-Roadmap.pdf (last visited Feb. 3, 2021).

A. We suggest that a cost allocation mechanism that ignores significant additional revenue benefits solely to one business line is equally biased and flawed.

Q. BPA also suggests that it "would be extraordinarily difficult" to develop a benefits-based approach to allocating the Grid Mod costs. How do you respond?

A. BPA acknowledges that, in certain circumstances, it may be appropriate to consider assigning costs to the ultimate beneficiaries. However, BPA suggests that in the context of the Grid Mod projects, it would be difficult to quantify and unbundle benefits that are intertwined between business lines. However, our understanding is that BPA's obligation to develop transmission rates that reflect an equitable allocation between Federal and non-Federal users of the system is not limited to cases where that allocation is easy. Fortunately, BPA and its customers had already developed the Cost Assignment Principles to govern cost allocation of non-wires projects that generate additional revenue benefits; see Section 2 of our testimony. BPA should apply those Cost Assignment Principles to the Grid Mod costs.

Applying the Cost Assignment Principles would result in allocating all of the Grid Mod costs to Power because BPA has not provided any evidence that transmission customers receive quantifiable benefits of any type at all. In fact, BPA concedes that it did not weigh qualitative benefits against quantitative costs in determining how to allocate the costs of Grid Mod.[92] Nor did BPA make any effort to assign those costs to the ultimate beneficiaries.[93]

Q. Are there any other concerns with the proposed allocation of Grid Mod Costs?

A. Yes, BPA's proposed allocation only deals with expense costs, not capital costs. Instead, capital costs will be included in capital planning for Transmission or Information Technology, and none will involve a new Power capital investment. By applying the same set of principles to govern cost allocation of non-wires projects that generate additional revenue benefits, the capital portion of investments for Grid Mod should be allocated 0/100% between transmission/power since BPA has not presented any evidence of quantified revenue benefits to Transmission. To be clear, this 0/100% allocation is predicated on the assumption—based on the evidence presented to date—that there are no quantifiable benefits to transmission customers associated with the Grid Mod projects.

Q. What is your conclusion regarding the proposed allocation of Grid Mod Costs in the absence of quantifiable benefits to transmission customers?

A. We conclude that BPA's proposal results in what appears to be an inequitable allocation of costs between Federal and non-Federal users of the transmission system because all transmission customers (Federal and non-Federal) benefit from

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92 BPA Response to MS-BPA-30-155 (BP-22-E-JP01-01-AT01 at 10).

93 BPA Response to MS-BPA-30-154 (BP-22-E-JP01-01-AT01 at 11).

the qualitative benefits equally, but transmission customers share none of the significant quantitative benefits.

Q. If BPA declines to adopt a 0/100 allocation of Grid Mod costs between Transmission and Power, do you suggest an alternative?

A. While it is not entirely consistent with the Cost Assignment Principles, another way to assign Grid Mod costs with quantified benefits would be to assign all EIM costs to Power and all non-EIM-related costs along BPA's proposed 65/35 allocation ratio. Grid Mod costs total $25 million for the rate period. Of those costs, $7 million is attributable to EIM Implementation, which would be directly allocated to Power. 65% of the remaining $18 million would be allocated to Transmission and 35% to Power. The result would be an approximately 45/55% allocation of Grid Mod between Transmission and Power. While our understanding is that such an approach may not necessarily result in an equitable allocation of costs between Federal and non-Federal users of the transmission system, it appears to be far less inequitable and more reasonable than BPA's current proposal.

Section 5: DERBS Rate Issues

Q. Please describe the changes BPA has proposed for the DERBS rate.

A. BPA has proposed a significant rate increase for customers with DERs who purchase balancing service from BPA. The DERBS rate for *inc* reserves will increase by 130%, while the DERBS rate for *dec* reserves will increase by 56%.[94]

Q. How did you calculate those percentage rate increases?

[94] BPA indicates the DERBS rate is increasing by 120%. Fredrickson *et al.*, BP-22-E-BPA-29 at 9.

A. In both cases, you subtract the current rate from the proposed BP-22 rate, then divide that result by the current rate and multiply by 100 to determine the percentage increase.

Q. Why is the rate increasing so dramatically?

A. BPA attributes the rate increase to three drivers. First, BPA suggests that the EIM market design places all SCE for DERs in the regulating reserve component. Second, BPA's cost of regulating reserve capacity is increasing to reflect the relative opportunity costs and value differences between regulating reserves and non-regulating reserves. Third, BPA indicates that the rate is increasing because dispatchable resources respond to BPA's price signals, resulting in less revenue than BPA anticipated but no reduction in BPA's costs; in other words, faced with a declining volume of demand for DERBS, BPA must increase the rate in order to recover its costs.[95]

Q. Do you have concerns with these justifications?

A. Yes, we have concerns with the first two of these drivers.

Q. What is your concern with regard to the first of BPA's justifications?

A. First, BPA seems to suggest that it is the EIM market design itself that requires BPA to shift all SCE for a DER into the more expensive regulating reserve component as opposed to allocating the SCE between a blend of expensive fast responding balancing reserves (regulating reserves) and slower and less expensive balancing reserves (non-regulating reserves).[96] Second, placing all SCE for DERs

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95 *Id.*

96 *Id.*

into the regulating reserve component is inconsistent with how BPA actually deploys its reserves.

Q. Please explain.

A. The EIM is a mechanism to settle energy imbalances. It automatically dispatches the cheapest available resources that have been bid into the market to meet the system's needs for incremental and decremental energy. Within the EIM, each generator and load settles its energy imbalances based at prices developed by the market (for generators, prices are settled at the LMP). But the EIM does not require BPA to allocate all SCE from DERs to the regulating reserve component, nor does it require BPA to allocate none of that SCE to the cheaper non-regulating reserve component. Additionally, the EIM does not require BPA to apply the incremental standard deviation methodology to SCE for DERs. BPA claims it must do so because that is what is applied to all other customers classes, but BPA fails to acknowledge that other methodologies could be applied to SCE, as long as those other methods were also applied to all the other customer classes.

Q. But what about the capacity screens you discussed earlier?

A. In order to fully participate in the EIM, BPA must satisfy the market operator that it has sufficient capacity and flexible capacity to meet its share of the forecast need for flexible capacity across the EIM footprint. If BPA failed to pass these screens, its ability to bid into the EIM would be limited until it succeeded in passing the screens. But for ratemaking purposes, BPA does not consider these screens in determining the total balancing reserve capacity needed for balancing services.[97] According to BPA's Balancing Reserve Capacity Business Practice, BPA Transmission Services holds capacity for Balancing Reserves to meet the NERC standards and Open Access Transmission Tariff ("OATT") requirements to maintain load-resource balance within its BAA boundaries.[98]

BPA does not fix the quantity of reserve capacity needed to meet its reliability requirements based on the EIM screens or how the EIM settles energy prices.

Q. What about DERs that choose to participate in the EIM?

A. A DER that chooses to participate in the EIM will settle imbalance directly with CAISO. In addition, the range of bids that are supplied to the market will contribute to BPA's ability to pass the capacity test portion of the resource sufficiency screens. For these reasons, DERs that participate in the EIM should not be subject to BPA's charges for SCE.

Q. Are there any other issues with BPA's explanation of why it proposes to allocate all reserves for DERs to regulating reserves?

A. Yes. The explanation is inconsistent with how BPA (or any BAA) deploys reserves over the course of an hour. Neither BPA nor any other BAA – or even the EIM – dispatches resources in response to the imbalance attributable to any single generator or load. Rather, reserves are deployed in response to the aggregated SCE of all the loads and generation in the entire BAA. There is no

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[97] Generation Inputs Study, BP-22-E-BPA-06 at 5; *see* BPA, BALANCING RESERVE CAPACITY: BPA TRANSMISSION BUSINESS PRACTICE V.1 (2019), https://www.bpa.gov/transmission/ Doing %20 Business/bp/tbp/Balancing-Reserve-Capacity-BP.pdf

[98] BPA, BALANCING RESERVE CAPACITY: BPA TRANSMISSION BUSINESS PRACTICE V.1 (2019), https://www.bpa.gov/transmission/ Doing %20 Business/bp/tbp/Balancing-Reserve-Capacity-BP.pdf

practical way that BPA (or the EIM market operator) can separate out the SCE attributable to a DER and deploy only regulating reserves for its imbalance. Likewise, there is no way that BPA (or the EIM market operator) can separate out the SCE attributable to a single load customer and deploy a mix of regulating and non-regulating reserves to that customer. Operationally, BPA will likely deploy regulating reserves on Automatic Generation Control ("AGC") to meet imbalances. Then if those deployments accumulate in one direction over time (either *incs* or *decs*), BPA will begin to deploy non-regulating reserves. As it does so, it will likely back off its AGC/regulating reserves to ensure that BPA continues to have sufficient headspace on its AGC units to meet future needs for fast-acting reserves. In any event, there is no practical way for BPA to determine that only regulating reserves are deployed to meet the SCE attributable to DERs. Nevertheless, BPA has arbitrarily chosen to allocate all SCE of DERs to the regulating reserve component based on how BPA has chosen to model the EIM Five-Minute Dispatches even though it is unreasonable to allocate all the SCE of DERs entirely to regulating reserves.[99]

Q. Are there any other issues with BPA's proposed DERBS rate?

A. Yes. As discussed above, the proposed rate for *inc* reserves under DERBS represents a 130% rate increase from the current rate. The proposed rate for *dec* reserves under DERBS is a 56% rate increase from the current rate. We believe that rate increases of this magnitude represent rate shock that should be mitigated.

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[99] *See* BPA Response,NI-BPA-30-19 (see attached BP-22-E-JP01-01-AT01 at 4); *see also* BPA Response,NI-BPA-30-7.

Q. Does BPA agree that rate increases of this magnitude constitute rate shock?

A. No. BPA considered mitigating this rate, but declined to do so.[100]

Q. What was BPA's reasoning?

A. BPA acknowledged that a 120% rate increase "seems large."[101] BPA then went on to assert that it must consider the relative dollar impact to BPA's customers and that DERBS is forecast to collect $1.2 million of BPA's $1.2 billion revenue requirement.[102] In our opinion, however, the fact that the DERBS rate is expected to recover only approximately 1/1000 of BPA's transmission revenue requirement suggests that there is an opportunity to mitigate the rate shock of a 130% rate increase to that small subset of customers who are exposed to the DERBS rate. BPA also only looked at DERBS customers as a whole, failing to evaluate the effect of the proposed increase on any particular customer. For at least one NIPPC member, the DERBS rate represents the only BPA rate that one of its entities is subject to. For this BPA customer, and any other similarly situated customer, it has no opportunity to dilute the rate shock with smaller increases to other rates. Thus, BPA has failed to properly conduct a rate shock analysis. BPA also argued that much of the rate increase is a result of an update in the billing determinants, which was necessary because DERBS customers have consistently used less of the service than BPA forecasted since the DERBS rate was adopted. BPA explains that the use-based rate design has allowed DERBS customers to avoid paying DERBS charges (by improving their scheduling

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[100] Fredrickson *et al.*, BP-22-E-BPA-29 at 11.
[101] *Id.*
[102] *Id.*

accuracy) but without reducing BPA's costs. In effect, BPA is complaining that the rate design it implemented is working. Instead of charging customers for a fixed quantity of reserves over the rate period like the other generation inputs rates, BPA designed the DERBS rate to encourage accurate scheduling. The more accurate a dispatchable generator is in scheduling and successfully keeping to its schedule, the less it will have to pay for balancing reserves.

Q. Does BPA have any other way to replace these revenues that DERBS customers have avoided?

A. Yes. Once BPA joins the EIM, it will be able to monetize all capacity it has set aside. The entire quantity of capacity set aside for non-regulating balancing reserves can be bid into the EIM and generate additional revenues as discussed previously in Section 2 of our testimony.

<u>Section 6: Capacity Charges for Loss Returns</u>

Q. What is your interest in transmission losses?

A. Together, NIPPC and RNW's diverse membership includes independent power producers, electricity service suppliers, marketers, storage resources, and others who use BPA's transmission. They would be subject to the losses policy, which BPA has proposed and documented in the BP-22 Rate Case Workshops, the Losses Policy testimony (BP-22-E-BPA-22), the Delayed Loss Return Capacity Cost testimony (BP-22-E-BPA-26), the Generation Inputs Study (BP-22-E-BPA-06), the Power Rates and Power Rate Schedule testimony (BP-22-E-BPA-16), the Transmission Rate Study and Rate Design testimony (BP-22-E-BPA-19), and the

2022 Transmission, Ancillary, and Control Area Service Rate Schedules and General Rate Schedule Provisions (FY 2022–2023) (BP-22-E-BPA-11).

Q. Please summarize this section of your testimony.

A. This section explains our opposition to the transmission losses policy and proposes an alternative that addresses BPA's capacity concerns and is fair for transmission customers. Our goals are to 1) ensure that practices for returning losses are just and reasonable; 2) incent BPA and its customers to promptly adopt a concurrent physical loss return practice to reduce reliance upon BPA's capacity; and 3) set a fair price for customers who choose to settle losses financially.

Q. Please summarize your recommendations.

A. It is unjust and unreasonable to impose a charge for losses that transmission customers cannot avoid due to existing practices. Instead of penalizing customers, BPA should follow through on its original plan from the late 1990's (as discussed below), and with transmission customers, create a truly concurrent loss return practice. We also recommend a necessary improvement in the price BPA charges for financially settling real power loss returns that is consistent with industry practice. In addition, we demonstrate how BPA's proposed capacity charge for loss returns cannot be avoided by customers due to an unfortunate artifact of BPA's business practices.

Q. What are your concerns regarding BPA's proposal to charge Point-to-Point customers for capacity associated with Loss Returns?

A. BPA customers may fulfill their obligation to return losses through the "In-Kind" Return option, which requires them to provide BPA with an energy schedule for the quantity of losses incurred from their schedule 168 hours earlier. Currently, BPA does not charge customers for this "service." In this rate case, BPA proposes to adopt a rate to charge customers for capacity associated with Delayed Loss Return Service.[103] As its testimony notes, BPA and its customers invested significant time and energy in the pre-rate case process to resolve their mutual concerns with the process, timing, and costs of transmission losses.[104] Towards the end of the pre-rate case workshop process, BPA discussed the potential of a concurrent loss return service. If BPA were to implement concurrent loss returns, it would be unnecessary to establish any rate for Delayed Loss Returns.[105]

Section 6.1: Overview of Capacity and Transmission Loss Returns

Q. What is your interpretation of BPA's intent with its proposed Transmission Loss Return Policy?

A. The policy is intended to recover the cost of capacity that BPA deems to be incurred in a specific situation, when the amount of energy BPA Power is providing to replace transmission losses in the operating hour is different than the amount of energy transmission customers are returning in that hour. This difference can occur because BPA's current Loss Return Business Practice requires customers to return their losses 168 hours after they are incurred. For example, BPA Power may be supplying 100 MW of energy for losses during Hour Ending ("HE") 10 on January 7 as customers return 90 MW of losses originally incurred during the same hour on January 1. Because the volume of

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103 Meyers *et al*., BP-22-E-BPA-22 at 4.
104 *Id*. at 7.
105 *Id.*

loss energy required now will rarely match the volume incurred one week ago, BPA must approximate the difference each hour and hold aside that volume of capacity. BPA's allocated revenue requirement for this capacity is proposed to be $8,186,897 during the 2022-23 rate period.[106] By establishing this new charge for transmission loss returns, BPA asserts that these costs are not currently recovered via the existing ACS Rates.

Q. How is BPA's current Loss Return Business Practice involved in this issue?

A. BPA's current Loss Return Business Practice v.15 dictates how customers must return transmission losses to BPA.[107] The business practice requires transmission customers who select to return losses "in-kind" to deliver those losses 168 hours after those losses are incurred. Returning to the example above, a customer who incurs losses during HE 10 on January 1 must return that amount of losses to BPA on HE 10 of January 7. In our view, the current Loss Return Business Practice is critically relevant to BPA's proposed transmission losses policy in two ways. First and most importantly, it is the source of the 168-hour delay. Customers who elect to return losses "In-Kind" cannot choose to return losses in any other time frame. Returning losses in the same hour they are incurred (truly concurrently) or any sooner than 168 hours after-the-fact is not an option. Second, in its testimony, BPA characterizes this mandated and unavoidable 168-hour delay as a "service," as if it is a desirable product that customers are voluntarily electing to take. It is a <u>requirement</u>, not a choice.

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106 Generation Inputs Study, BP-22-E-BPA-06 at 84.

107 BPA, REAL POWER LOSS RETURN: TRANSMISSION BUSINESS PRACTICE V.15 (2019) (see attached BP-22-E-JP01-01-AT02 at 112-18).

Q. Does the current Loss Return Business Practice v.15 make BPA's proposed charge unjust, and if so, what do you propose as an alternative?

A. Yes. With the proposed charge, BPA would unfairly penalize customers who are bound by the current Loss Return Business Practice, specifically, that returns must be made 168 hours after-the-fact. BPA's proposed capacity charge does not fix the problem. BPA should focus on eliminating the 168-hour delay by implementing a truly concurrent loss return practice where customers are able to return losses in the same hour they are incurred. As stated in BPA's testimony, a capacity charge is unnecessary for concurrent loss returns.

Q. Are concurrent loss returns a new idea?

A. No. As early as 1993, BPA promised to "provide Transmission Customers the opportunity to schedule concurrent losses within two (2) years."[108]

Q. Did BPA meet that commitment to offer transmission customers concurrent loss returns?

A. No. But at some point in approximately 2001, BPA struck that promise from its Transmission Tariff.

Q. If loss returns did not become concurrent, what happened instead?

A. BPA developed loss return business practices, which required transmission customers to return Real Power Losses 168 hours after the service was

[108] BPA Transmission Tariff, TC-96-FS-BPA-02 at 87 (Jan. 11, 1993) (see attachedBP-22-E-JP01-01-AT02 at 135).

provided. The practice persists today in the form of the Loss Return Business Practice v15.[109]

Q. Does BPA intend to develop practices that facilitate concurrent loss returns?

A. Yes. Unfortunately for a variety of reasons, BPA claims that it cannot implement them before the end of FY 2023. Instead, it proposes to devote significant staff time to develop a new capacity charge rate along with new billing processes, which will then be abandoned when concurrent loss returns can be implemented. Such an approach does not appear to be consistent with our understanding of the requirement to set rates in accordance with sound business principles.

Q. Do you have an alternate recommendation?

A. Yes. We recommend that BPA abandon its decision to commit staff time and resources to developing a new and unique rate that will be in place for less than two years. If BPA truly believes that the capacity set aside for loss returns is significant, then it should implement a new business practice in which customers must provide sufficient additional energy at the point of receipt ("POR") to cover the loss obligation associated with their schedule. For example, if losses are 2%, then a customer seeking to schedule 100 MW would inject 102 MW at the POR.

Q. Do you have an alternate recommendation that, in your view, would also make financial settlement of losses just and reasonable?

A. Yes. We recommend that BPA follow Pacific Northwest industry standards and charge an hourly index price for loss returns that are settled financially, such as

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[109] BPA, REAL POWER LOSS RETURN: TRANSMISSION BUSINESS PRACTICE V.15 (2019) (see attached BP-22-E-JP01-01-AT02 at 115).

PacifiCorp, Portland General Electric, and Puget Sound Energy, that use their Balancing Area Load Aggregation Point Locational Marginal Prices ("LAP LMP") to price financial loss returns.

Q. Do the concerns you raise in Section 2.2 regarding overcollection of variable costs apply here as well?

A. Yes. BPA's proposal would result in it collecting its opportunity costs twice in these rates as well. BPA proposes to collect its opportunity costs in the capacity rate it charges customers and will collect those opportunity costs again in the settlement of the energy price.

Section 7: Revenue Financing (Borrowing Authority)

Q. Can you summarize your view of BPA's proposal to use "revenue financing" to support its capital investment needs?

A. Yes. The use of revenue financing creates measurable, inappropriate, and discriminatory intergenerational inequities. BPA's proposal would place the cost of long-lived transmission capital expenditures on the backs of current ratepayers for the benefit of future generations. BPA's need for capital, if it cannot be addressed with spending controls, is better addressed through changes to its access to non-federal debt or U.S. Treasury borrowing capacity.

Q. What is "revenue financing" and its impact on rates?

A. BPA defines revenue financing as "raising cash through rates to pay for capital investments."[110] Simply put, BPA seeks to increase transmission revenue requirements by $45 million in each year of the BP-22 rate period and use the

[110] Fredrickson *et al.*, BP-22-E-BPA-17 at 4.

resulting revenue to fund long-lived capital investments. BPA indicates that this proposal alone would raise rates by approximately 4.5%.[111] BPA's Leverage Policy, the basis of its proposal here, would have current ratepayers fund a stunning $644 million in capital investments through revenue financing over the next 4 years.[112] BPA's proposal is essentially a method to generate excess revenue in order to fund investments directly from ratepayers through rate increases.[113]

Q. Does BPA acknowledge these rate increases?

A. Yes, in part. BPA recognizes the significant upward pressure on transmission rates, but claims that the proposed $45 million per year in revenue above the actual costs of operating the transmission system is in line with what BPA has shared with customers regarding its strategy to implement its financial plan.[114]

Q. What is your understanding of BPA's goal in requiring customers to finance capital projects through revenue financing in rates?

A. We understand BPA is attempting to manage its limited borrowing authority for the benefit of future customers. But while BPA has formally adopted a Financial Reserves Policy (to manage its financial reserves) and a Leverage Policy (to manage its debt-to-asset ratio), BPA has not formally adopted any policy related to management of its borrowing authority between specific business units.[115]

Q. What are the implications of BPA's revenue financing proposal?

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111 *Id.* at 11.
112 *Id.* at 4.
113 *Id.* at 8.
114 *Id.* at 12.
115 BPA Response, PP-BPA-30-33; *see also* BPA Response, PP-BPA-30-34 (see attached BP-22-E-JP01-01-AT01 at 5-6).

A. BPA effectively treats its customers as BPA's lender of last resort. In its revenue financing proposal, BPA is choosing to significantly burden its current customers while acknowledging that reducing capital spending would lower the demand for investment funds and extend access to borrowing authority. To make matters worse, in 2018, BPA implemented self-imposed limits on its use of borrowing authority through the Leverage Policy and debt capacity targets.[116] In effect, BPA's customers become BPA's only source of capital if the capital investment program established in the IPR exceeds the guidelines set in the 2018 Financial Plan.[117] When BPA considers its obligations to meet its capital needs at its lowest possible costs, it considers only its own costs[118] and does not consider the costs of revenue financing imposed on customers.

Q. You state that revenue financing creates measurable intergenerational inequities. Please explain.

A. BPA describes intergenerational equity as an analysis of "whether one generation is paying a reasonable amount of the costs … of something that impacts multiple generations of people."[119] The logical (albeit unstated) conclusion of this analysis is that if one generation is paying an unreasonable amount of the costs, while other generations benefit, there is a form of discrimination and preference that can be characterized as an intergeneration *inequity*. BPA's proposal to fund long-lived capital with current revenues forces current customers to pay the full cost of investments that have useful lives for decades. Future customers obtain the

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116 BPA, 2018 FINANCIAL PLAN (see attached BP-22-E-JP01-01-AT02 at 119-34).
117 BPA Response, MS-BPA-30-35.
118 BPA Response, MS-BPA-30-59 (see attached BP-22-E-JP01-01-AT01 at 7).
119 Fisher *et al.*, BP-22-E-BPA-15 at 19.

benefits of the more robust, reliable, and potentially expanded transmission network without having to share in any of the costs. This is a clear demonstration of an intergenerational inequity. BPA has not provided sufficient evidence to support the imposition of this inequity on current customers.

Q. You say that this inequity is measurable. So for a $45 million investment, what would be the estimated difference in the current-year revenue requirements between traditional ratemaking and revenue financing?

A. First, we note that $45 million in revenue financing results in an increase in the revenue requirement of $45 million and as reported by BPA, a 4.5% rate increase.[120] Assuming those assets were 1) depreciated on a straight-line basis and amortized over their useful life; and 2) were debt-financed at 4% with 2% O&M and no tax obligation, then the resulting revenue requirement would be approximately 8% of the capital investment, or approximately $3.6 million per year. Under this approach, the increase in rates would be less than one-half of one percent. Accordingly, the intergenerational inequity can be estimated at approximately $40 million dollars (as the difference in current revenue requirements).

Q. BPA also addresses intergenerational equity in BP-22-E-BPA-15. Do you agree with the panel's conclusions?

A. No. BPA inappropriately applies intergenerational equity to the immeasurable and entirely speculative costs and benefits of the preservation of BPA's borrowing authority. BPA does not provide any evidence of the impacts or costs

[120] Fredrickson *et al.*, BP-22-E-BPA-17 at 11-12.

of utilizing incremental borrowing authority now, nor does it estimate the benefits of using borrowing authority later. In fact, BPA's assertion that the deferral of borrowing creates benefits for future generations is self-defeating. Why is it reasonable that current customers pay (as in revenue financing) for the benefit of future generations? Even by BPA's definition, its proposal embodies intergenerational inequities and should be rejected.

Q. In spite of your recommendations, if BPA moves forward with revenue financing, how should it adjust its depreciation schedules?

A. Investments that are funded with revenue financing must be considered similarly to expenses. They should have no depreciable asset value. BPA should target and separately track the assets that are funded through revenue financing and verify that they do not contribute to depreciation expense. To do otherwise would create unreasonable double-collection of investment costs – once by raising rates to fund the investment and again subsequently to collect depreciation.

Q. BPA says it is not aware of legislation currently pending which would increase its borrowing authority; are you aware of any such legislation?

A. Not at this time, no. While by no means certain, we believe that there is sufficient possibility of enactment of legislation expanding BPA's borrowing authority prior to the beginning of the BP-22 rate period to justify BPA preparing for that eventuality in this rate case.

Q. Do you have a recommendation regarding what BPA should do if its borrowing authority is expanded?

A. Yes. BPA should include a mechanism to reduce the BP-22 transmission rates by the amount of revenue financing included in the rates documented by the Final Record of Decision in the event that Congress does act to increase BPA's borrowing authority.

Q. Do you have any other recommendations related to this topic?

A. Yes. BPA has placed the capital program established in its IPR process outside the scope of this proceeding so we will not address any specific proposed capital expenditure here. Notwithstanding that BPA has committed to a second IPR process,[121] we recommend that BPA revise the process it uses to establish its capital spending program so that the limitations imposed by BPA's Financial Plan (especially the Leverage Policy and borrowing authority limits) serve as a cap on BPA's capital spending program. Currently, BPA does not consider limited access to capital in its IPR process. In the absence of such a cap,[122] BPA will continue to rely on revenue financing from customers to cover the shortfall between its capital spending program and the limits imposed by the Financial Plan. To the extent that BPA finds it cannot make a determination in this proceeding regarding a process revision along the lines of our recommendation, we request that BPA commit to leading one or more workshops outside of the rate case process to consider this suggestion.

Section 8: Conclusion

Q. Does this conclude your testimony?

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121 Lennox *et al.*, BPA-22-E-BPA-20 at 19-20; *BP-22 Integrated Program Review*, BPA, https://www.bpa.gov/Finance/FinancialPublicProcesses/IPR/Pages/IPR-2020.aspx (last visited Feb. 2, 2021).

122 *See, e.g.*, BPA Response, MS-BPA-30-33.

A. Yes.