BP-26 Rate Case & TC-26 Tariff Proceeding Workshops
Summary of Written Comments Received and BPA Staff's Reponses

Last Updated: October 10, 2024

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I. Comments Received in Response to the March 19, 2024 BP/TC-26 Kick-off Workshop

Row #	Stakeholder	Comment	BPA Staff Response
1	Harney Electric Cooperative	**Transmission Rates -** Request for topic to be included in the workshops, led by either BPA staff or customer led: The Short-Distance discount (SDD) which adjusts an NT customer's Network Load calculation if it has a designated Network Resource that uses less than 75 circuit miles for delivery to the load. We wish to explore decreasing the credit limit (currently set at 40%). This discount is currently described in BPA's Transmission General Rate Schedule Provisions, but does impact the definition of Network Load.	The current Short-Distance Discount for the NT is set to a maximum of 60%, which BPA believes properly incents customers' behavior and reflects the value gained from locating Points of Delivery near Points of Receipt. BPA staff does not plan to propose any changes to this formula as it incents the correct customer behavior. If customers would like to present a proposal with reasons how it will maintain the customer behavior staff is seeking, staff is open to listen at a customer led workshop.
2	Harney Electric Cooperative	**Transmission Rates -** Request for topic to be included in the workshops, led by either BPA staff or customer led: Acknowledgement that, if a customer can demonstrate that investments in net load and/or automatic/instantaneous load shedding have been made that operationally limit (with virtual certainty) transmission service, then such operational limit is used as the billing determinant for NT charges. This encourages smart-grid investment and ensures that transmission customers are not charged for "stand-by" transmission service they cannot/will not utilize. This acknowledgement could be in the form of a simple written interpretation to NT customers, or language added to BPA's Transmission General Rate Schedule Provisions, i.e., Network Integration Rate, Section IV, Adjustments, Charges, and other Rate Provisions.	Thank you for your comment. BPA staff encourages Harney Electric Cooperative to submit a request to present this topic and any proposal at a customer-led workshop.

Row #	Stakeholder	Comment	BPA Staff Response
3	Harney Electric Cooperative	**Power Rates -** Request for topic to be included in the workshops, led by either BPA staff or customer led: Clarifying where necessary that the wording "connected to Harney Electric Cooperative's distribution system" within the definition of "Consumer-owned Resource" in HEC's Regional Dialogue Power Sales Agreement includes all of HEC's distribution system regardless of the voltage level at the point of such connection to HEC's distribution system.	Thank you for your comment. Harney requested Bonneville to include a workshop topic to clarify the definition of "Consumer-Owned Resource" from the Regional Dialogue Power Sales Contract. Regional Dialogue contract language explanations are not a rate case topic and are outside of the scope of the BP-26 rate case proceeding. Bonneville encourages Harney to work with their Power Account Executive regarding questions about its Regional Dialogue contract. To the extent Harney would like to discuss changes to contract language for Post-2028, Bonneville encourages Harney to provide feedback through the Provider of Choice Policy Implementation and Contract Development phases workshops that began April 2024.
4	NLSL Group	As mentioned by BPA during the workshop, an NR service election has been made by a BPA customer to serve an NLSL. The NLSL Group agrees that quite a bit of education will be required to fully understand the intent and the proposed methodology of the NR Rate. BPA has stated that it plans to discuss NLSL issues at the July 30th and 31st workshops, but the NLSL Group believes that at least one follow-up workshop will be required to fully explore the intent and methodology of the proposed NR rate design and to respond to staff as well as customer questions.	We agree that the NR issues will likely require more than a single workshop to allow for sufficient time to understand, consider and respond. As such, we will commit to having at least two workshops that include NR-related issues prior to the release of the Initial Proposal.
5	NLSL Group	Most existing NLSL load is met with bilateral market purchases that are shaped to the actual metered NLSL loads using BPA's Energy Shaping Service (ESS). In order to avoid UAI penalties, customers significantly overschedule HLH energy deliveries and must either assume plant outage risk or place significant cost risk on suppliers through non-standard liquidated damages provisions that adversely affect market liquidity. The NLSL Group is interested in exploring alternative methods for avoiding UAI penalties that will more accurately reflect costs incurred by BPA, result in more accurate scheduling practices, and result in equitable outcomes when suppliers have unplanned contingencies.	We intend to spend some of the NR-related workshop time on ESS and welcome customer proposed improvement suggestions for staff to consider. One of BPA staff's main concerns with ESS is that the capacity obligations and cost of meeting those obligations are clearly defined and equitably allocated. There are often many right ways to achieve this stated result. As such, the NLSL load customers should consider presenting at a customer-led workshop to go over potential alternative approaches. BPA would be particularly interested in understanding how such approaches do, or do not, meet the capacity obligations of following NR load.

Row #	Stakeholder	Comment	BPA Staff Response
6	NLSL Group	The NLSL Group would like to explore the NR Resource Flattening Service (NRFS), which has been included in BPA's General Rate Schedule Provisions as a way to use specified resources that could be shaped by the federal system in order to serve NLSL loads. After conversations with BPA, it is the NLSL Group's understanding that BPA may or may not choose to offer this product in the future. The NLSL Group would like this service option to be discussed as part of the NLSL topic.	We will add this to the list of items to cover during our NR-related workshops.
7	NLSL Group	NLSLs generally have on-site generation and many are exploring modernizing this generating supply with resources that can be used for purposes other than back-up generation (for example, these generating resources could be dispatched to displace other generating resources or committed to provide reliability capacity). It is the NLSL Groups' understanding that a customer must pay NT service for the gross amount of load irrespective of whether there is on-site generation that is operationally netted against the gross NLSL load. As part of TC-26, the NLSL Group would like to discuss what would be necessary for the customer to demonstrate to BPA that the on-site generation is reducing the NLSL load thus justifying a reduction to the NT service billing determinant.	Currently, BPA is not considering any changes to the NT service billing determinant for NSLSs based on reductions from on-site generation. The gross amount of load is used as the billing determinant as that amount is still required to be reserved for the NLSL and might be called upon to be served at any point. If NLSL Group has a proposal, we encourage you to submit a request to present this topic and any proposal at the customer led workshop.
8	NRU	**Workshop Process -** NRU continues to support BPA's six step approach to customer engagement and believes it has served both BPA and its stakeholders well in past processes.	Thank you for your comment.
9	NRU	**Rate Principles -** Regarding the proposed Principles, of primary importance to NRU members is BPA's ability to offer an affordable and reliable power supply that maximizes the value of the Federal system for the benefit of preference customers. Given the available information, BPA's proposed BP-26 Principles appear to be aligned with that end goal.	Thank you for your comment.

Row #	Stakeholder	Comment	BPA Staff Response
10	NRU	**Tariff Principles -** NRU appreciates that the proposed TC-26 Principles highlight the fact that BPA will consider differences from the FERC pro forma tariff if the difference is necessary to prevent significant harm or provide significant benefit to BPA's mission or the region, including BPA's customers and stakeholders. As BPA and its customers continue to work through the queue reform process that began with TC-25 and given the necessity of long-term firm NT access to NRU members, BPA's willingness to deviate from the pro forma tariff may be essential as we move toward day-ahead market integration and Provider of Choice contract implementation.	Thank you for your comment.
11	NRU	**Power Rates -** Supportive of the Power Rates Topics that BPA proposed and asks that Tier 2 Pricing and Demand Pricing be added to the list, with time set aside for discussion and consideration.	BPA will plan to discuss Tier 2 and Demand rate pricing at the July 30-31 BP/TC-26 pre-proceeding workshop.
12	Seattle City Light	**Workshop Process -** Suggests that the approach to complete steps 1-6 in a single workshop provides a limited amount of customer engagement and question time within scheduled meeting time, and does not leave adequate time for step 5, "Discussion of Customer Feedback" prior to the step 6 staff proposal. One option City Light recommends BPA consider is to provide customers with key questions and issues for feedback two weeks prior to the BPA workshop where the topics will be covered. BPA could provide these through a Tech Forum email and request that customers respond within one week. Alternatively, BPA could provide the meeting materials a full two weeks prior to the BPA workshop. Customers could provide feedback in the same one-week time frame to allow BPA staff time to consider and incorporate customer perspectives.	Thank you for your comment. As suggested, we will endeavor to include specific questions for each topic to help focus customers' responses; however, this does not mean customers cannot provide comments on the topic other than responding to the specific questions.
13	Seattle City Light	**Rate and Tariff Principles and Workshop Process -** Supports the BP-26 and TC-26 Principles and grouping in person workshop meetings on successive days to reduce travel to and from workshops.	Thank you for your comment.

II. Comments Received in Response to the April 24, 2024 BP/TC-26 Workshop

Row #	Stakeholder	Comment	BPA Staff Response
14	Seattle City Light	**Segmentation** City Light supports BPA's proposal maintaining the current methodology and segment definitions. City Light recognizes and thanks BPA for the resources and effort BPA expended on the last segmentation study.	Bonneville appreciates Seattle City Light's comments on segmentation.
15	Seattle City Light	**ACS Rate for ESDs** City Light supports the BPA objectives and criteria for evaluation for the ACS for ESDs. Specifically, City Light applauds BPA emphasizing equitable treatment and following cost causation principles. City Light additionally supports BPAs intent to develop an Energy Storage Device Balancing Service (ESDBS) like the existing DERBS to capture the cost of Balancing Capacity for energy storage devices that can be applied to both discharging and charging.	Thank you for your comment.
16	Seattle City Light	**GI Withdrawal Penalties** City Light supports BPA developing and implementing Generator Interconnection withdrawal penalties to reduce delays and costs associated with restudy.	Thank you for your comment. We will consider this as we are considering alternatives and our proposal.
17	Seattle City Light	**GI Withdrawal Penalties** *How should penalties be calculated? When should the penalty apply?* City Light suggests BPA follow the principle that withdrawal penalties are meant to deter non-viable projects from entering or remaining in the interconnection queue and to mitigate potential harm to other interconnection customers in the queue. City Light recommends BPA consider multiplying the study deposit for each phase of the process to calculate the withdrawal penalty for withdrawing from that phase. City Light believes this is the most transparent and easily implementable way to calculate penalties. Penalties for phase 1 should be equal to the study deposit with late phases being a higher multiple.	Thank you for your comment on how withdrawal penalties should be calculated. We will consider this as we are determining our alternatives and proposal.

Row #	Stakeholder	Comment	BPA Staff Response
18	Seattle City Light	**GI Withdrawal Penalties** *When does the penalty apply? During the Transition Process?* City Light recommends that withdrawal penalties should apply to each phase of the Transition Process and after.	Thank you for your comment on when a withdrawal penalty should apply. We will consider this as we are determining our alternatives and proposal.
19	Seattle City Light	**GI Withdrawal Penalties** *Should there be exceptions to when a penalty applies?* City Light recommends limiting exemptions from withdrawal penalties to the following: • Withdrawal does not have a material impact on the cost or timing of any interconnection requests. • Withdrawal follows an unanticipated increase in network upgrade cost estimates and the network upgrade costs assigned to the interconnection customer's requests have increased by 100% compared to the costs identified in the previous cluster study report.	Thank you for your comment on exceptions to when a withdrawal penalty applies. We will consider this as we are determining our alternatives and proposal.
20	Seattle City Light	**GI Withdrawal Penalties** *How should Withdrawal Penalty funds be allocated?* City Light recommends the following for allocating Withdrawal Penalty funds: • First, to cover the costs of mitigating potential harm to other interconnection customers in the queue by applying penalty amount to the costs of the affected study phase. • Next, any remaining funds are used to offset any remaining customer's net increases in network upgrade costs caused by the customer's withdrawal (due to a previous shared funding obligation); and • Next, any remaining funds are used to offset network upgrade costs of customers participating in the cluster study; and • Finally, any remaining funds are returned to the withdrawal customer.	Thank you for your comment on how withdrawal penalty funds should be allocated. We will consider this as we are determining our alternatives and proposal.

Row #	Stakeholder	Comment	BPA Staff Response
21	Seattle City Light	**GI Withdrawal Penalties** *Are there other elements we should consider?* City Light recommends BPA consider the ramifications of requiring a withdrawal penalty greater than the amount of a requesting customer's deposits. Some type of deposit, bond, and or other credit requirements may need to be met for withdrawal penalties to be effective in each phase of the process.	Thank you for your comment. We will consider this as we are determining our alternatives and proposal.
22	Seattle City Light	**GI Reform – Affected Systems** City Light supports BPA developing an efficient, consistent, and sustainable process for performing Affected System studies in parallel with TSEP and interconnection studies that coordinates with neighboring Transmission Providers' processes.	Thank you for your comment. BPA staff are clarifying that the scope of this topic is limited to the large generator interconnection process and is not considering any changes to TSEP.
23	Seattle City Light	**GI Reform – Affected Systems** *What visibility of Affected System Studies do customers need?* Customers whose requests cause an Affected System Study need should have the same visibility into the study process as customers whose requests are directly being studied in the process. This should be true regardless of what process the Affected System Studies need is being studied by BPA. City Light suggests that BPA could include an Affected System Study segment in the needed network upgrade portion of each phase of the generator interconnection process as well as the TSEP cluster study process.	BPA staff will address this comment in its presentation at the June 26th BP/TC-26 workshop.
24	Seattle City Light	**GI Reform – Affected Systems** *What is the most efficient, consistent, and sustainable process for performing Affected System studies in parallel with the new two-phase cluster study process for requests in BPAs interconnection queue?* City Light recommends BPA cluster Affected System Studies needs and include those needs in the next BPA study process accessing network impacts and needs. This could be part of each phase of interconnection study as well as the TSEP cluster study.	BPA staff will address this comment in its presentation at the June 26th BP/TC-26 workshop.

Row #	Stakeholder	Comment	BPA Staff Response
25	Seattle City Light	**GI Reform – Affected Systems** *How will BPA coordinate better with other Transmission Providers' processes?* Following the above, BPA should be assessing network needs and upgrades once a year. This should be sufficient to coordinate with other Transmission Providers' processes. Anything less, is likely to be seen as insufficient by both customers and neighboring Transmission Providers.	BPA staff will address this comment in its presentation at the June 26th BP/TC-26 workshop.
26	Seattle City Light	**GI Reform – LGIA** City Light supports efforts to align BPA's Tariff LGIA template with TC-25 reforms and/or the pro forma Tariff.	Thank you for your comment.
27	Savion	**GI Withdrawal Penalties** Savion, LLC ("Savion") strongly recommends the Bonneville Power Administration ("Bonneville") implement interconnection withdrawal penalties consistent with Federal Energy Regulatory Commission ("FERC") guidance...One potential deviation Bonneville should explore with stakeholders is whether there should be "penalty free" exit points in either Bonneville's Transition Cluster Study and the Durable Cluster Study Processes.	Thank you for your comment. We will consider this as we are determining our alternatives and proposal.
28	Savion	**GI Withdrawal Penalties** 1. Bonneville Must Establish Withdrawal Penalty Policies That Encourage Non-Viable Projects to Exit the Queue Voluntarily Consistent with FERC's final rules, Savion encourages Bonneville to implement withdrawal policies that: 1) Aim to minimize re-studies and cascading withdrawals that are likely to have negative impacts on other interconnection customers; 2) Escalate as customers progress through the interconnection process; 3) Allow for reasonable exceptions, exemptions; and 4) Allocate penalty funds to hold other interconnection customers harmless.	Thank you for your comment. We will consider this as we are determining our alternatives and proposal.

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29	Savion	**GI Withdrawal Penalties** 2. Bonneville Should Consider Specific Exit Points for "Penalty-Free" Withdrawals Before Network Upgrade Costs, Allocations are Provided. When considering the best way to utilize withdrawal penalties to reach the goals outlined above, Savion notes that FERC's rules set penalty amounts that are akin to a penalty-free withdrawal before network upgrade costs estimates are allocated. For simplicity, Bonneville should consider applying withdrawal penalties only after the phase one ("P1") study results. Under a pro forma tariff, if an interconnection request is withdrawn during the initial cluster study or after the initial cluster study report the customer is assessed only the higher of the study deposit or two times the actual study costs. FERC refers to this as a "withdrawal penalty" but this amount is essentially immaterial in the context of a standard large generator. Despite FERC's unfortunate terminology, the penalty amount before network upgrade estimates are assigned does little more than compensate the transmission provider for the costs of running the study. This is not really a penalty. Although Savion believes that all commercially viable projects should be backed by escalating amounts that are "at risk", any such amounts that truly seek to penalize are not appropriate until the interconnection customer has had the opportunity to review the facilities and network upgrade cost estimates associated with their projects. To that end, Savion recommends Bonneville either waive penalties during P1 or at a minimum limit cost exposure to the study deposit amount.	Thank you for your comment. We will consider this as we are determining our alternatives and proposal.
30	Savion	**GI Withdrawal Penalties** 3. Bonneville May Want to Reconsider Deposit Amounts That Are Now "At Risk" as Withdrawal Penalties to Ensure There is Sufficient Security to Give Withdrawal Penalties Meaning	Thank you for your comment. We will consider this as we are determining our alternatives and proposal.

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		Savion understands that Bonneville is considering implementing withdrawal penalties, which may be based upon deposit amounts established in the TC-25 settlement. Savion also notes, however, that FERC clarified in Order No. 2023-A that withdrawal penalties cannot exceed the amount collected from interconnection customers. To the extent appropriate, Bonneville should review each of the interconnection decision points to ensure: 1) Study deposit amounts are set sufficient to recover study costs (and not set higher to help provide security); 2) Commercial readiness deposit amounts are set sufficient to demonstrate viability (and not set higher to provide security); and 3) Security postings are collected to advance beyond P1 study results where needed to ensure penalties provide sufficient "at-risk" incentives.	
31	NIPPC and RNW Joint Comments	**Segmentation** Our comments on Segmentation are limited to the proposed "plant in service forecast" for the years 2024-2029. BPA has decided that the BP-26 rate period will cover three years—not the normal two-year rate period for BPA rates. Historically, BPA has struggled to fully and consistently execute the capital spending program approved in the Integrated Program Review ("IPR") during a two-year rate period. In recognition of the consistent delta between forecast and actual capital investment, BPA now incorporates into its ratemaking process a lapse factor of 10% of the forecast capital spending plan to reflect the inconsistency in BPA's ability to fully execute its capital spending forecast. Commenting Parties suggest that the uncertainty around a three-year capital spending forecast will be greater than the uncertainty of a two-year capital spending forecast. Further analysis is needed to better evaluate what constitutes an appropriate lapse factor over a three-year rate period. Commenting Parties encourage BPA to apply an appropriate lapse factor to the first two years of the capital spending forecast developed in the IPR, with a higher lapse factor for the third year of the rate period. Rather than locking in higher rates based on a very uncertain capital spending forecast, BPA should rely on the Cost Recovery Adjustment Clause mechanism to temporarily increase rates if BPA is able to fully execute the capital	Bonneville appreciates the comments on segmentation and capital execution rates. The capital spending forecast should be addressed during the Integrated Program Review (IPR) workshops, scheduled to start June 27, as it is not directly a segmentation topic. Bonneville sets rates to recover its forecast costs, by statute. The Commenting Parties appear to suggest Bonneville set rates lower than necessary to recover all forecast costs and instead rely on risk adjustment mechanisms to achieve cost recovery during the rate period. The Commenting Parties' primary focus issue is the reasonableness of BPA's cost forecast to be discussed during the IPR process. The transmission cost recovery adjustment mechanism provides for an adjustment to rates if actual results during the rate period differ from the cost forecast at the time rates are set. It is not intended to substitute for setting rates based on that forecast.

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		spending plan developed in the IPR across all three years of the rate period.[1] [1] Commenting Parties do not agree that the Revenue Distribution Clause ("RDC") is an effective tool to provide rate relief to customers when BPA is unable to execute its planned capital spending program during the rate period. While BPA Transmission has consistently over-collected revenues from transmission customers to the point where the RDC triggers on a regular basis, BPA has also consistently used the surplus revenues for "other high value uses" rather than using those surpluses to provide the rate relief which customers seek.	
32	NIPPC and RNW Joint Comments	**ACS Rate for ESDs** Commenting Parties encourage BPA to maintain the status quo for BP-26 and not develop a use-based capacity charge for ESDs given the following uncertainties: • BPA acknowledges that it does not yet have sufficient data on the effect of ESDs on its system to calculate the amount of balancing capacity needed. • As far as requests in the queue, BPA has not yet begun the Transition Cluster Study for interconnections; many of the requests to interconnect ESDs may withdraw or be unable to meet the requirements to remain in the Transition Cluster. • Even if ESDs come onto BPA's transmission system, it is not clear what their impact on balancing reserves would be. Many ESDs are quite flexible...ESDs do not share the operating limitations that some thermal and renewable generators have that drive the need for imbalance reserves. • It is not yet clear how the owners of ESDs will operate those devices.	Thank you for your comments. BPA staff will consider them as we continue to evaluate the alternatives. We will address comments in further detail and present the staff proposal (steps 5-6) at the August 27-28 BP/TC-26 workshop.
33	NIPPC and RNW Joint Comments	**ACS Rate for ESDs** If the pace of installation of ESDs towards the end of the upcoming rate period and other market developments justify it, BPA can initiate a stand-alone rate case to develop its proposed use-based charge for ESDs. At that time, there may be more clarity around the day-ahead market rules that would apply.	Thank you for your comment.

Row #	Stakeholder	Comment	BPA Staff Response
34	NIPPC and RNW Joint Comments	**ACS Rate for ESDs** BPA's generation inputs SMEs should prioritize updating the generation inputs rates to reflect the EIM rather than developing a new charge for ESDs without the data or analysis to support it.	Thank you for your comment. Please see slides 32, 34-35 of the Feb. 22 customer workshop presentation on Balancing Reserves, OCBR and OMP, where BPA staff address the BPA BA need to maintain Balancing Capacity Levels in the EIM. The slides are available in the Meetings and Workshops section of the BP-26 Rate Case webpage.
35	NIPPC and RNW Joint Comments	**GI Withdrawal Penalties** Commenting Parties share the concerns BPA has articulated regarding the impact of withdrawals from the interconnection queue, particularly on the delays in completing the cluster study. Customers who withdraw from the interconnection queue may impact other customers in a variety of ways. Customer withdrawals may create a need for additional studies/restudies and may impact the cost burden of other customers. In addition to the impact on other customers, withdrawals also strain the workload of BPA staff. Other transmission owners have noted that withdrawals trigger restudies and cost reallocations that trigger subsequent withdrawals, thus making it difficult to complete studies on schedule. The Federal Energy Regulatory Commission ("FERC") has attempted to address this problem in Orders 2023 and 2023-A by providing for withdrawal penalties in the pro forma Open Access Transmission Tariff. Commenting Parties recommend that BPA adopt a withdrawal penalty mechanism consistent with Orders 2023 and 2023-A.	Thank you for your comment. We will consider this as we are determining our alternatives and proposal.
36	NIPPC and RNW Joint Comments	**GI Withdrawal Penalties** *How to Calculate the Withdrawal Penalty* Commenting Parties recommend that BPA align with FERC Orders 2023 and 2023-A with respect to calculation of withdrawal penalties. • If a customer believes that its project is ready to enter the interconnection cluster study process, then the customer should be willing to demonstrate that confidence by having funds at risk above its share of the cost of the interconnection study (as explained further below). • The magnitude of the penalty should increase with each phase.	Thank you for your comment on how to calculate the withdrawal penalty. We will consider this as we are determining our alternatives and proposal.

Row #	Stakeholder	Comment	BPA Staff Response
		• In the initial phase of the cycle, the withdrawal penalties should be based on a multiple of the study costs. • In subsequent phases, calculation of the withdrawal penalty for any given customer should be based on a percentage of that customer's forecast network upgrade costs.	
37	NIPPC and RNW Joint Comments	**GI Withdrawal Penalties** *When to Apply a Withdrawal Penalty (Transition Cluster)* • No withdrawal penalties should be applied to any customer who withdraws from the Transition Cluster before the effective date of the BP-26 transmission rates (October 1, 2025). • Even if there are delays in the cluster study cycle, no withdrawal penalty should attach to customers who withdraw after their receipt of the initial Phase 1 Study results of the Transition Cluster • Withdrawal penalties should attach only to cluster study phases that begin after the effective date of the BP-26 rates; thus, such penalties could apply to any restudies of Phase 1 or the initial Phase 2 Study. Encourage BPA to provide stakeholders with additional information on how BPA envisions applying such penalties.	Thank you for your comment on when to apply a withdrawal penalty. We will consider this as we are determining our alternatives and proposal.
38	NIPPC and RNW Joint Comments	**GI Withdrawal Penalties** *When to Apply a Withdrawal Penalty (Durable Cluster Study Process)* • Support BPA adopting withdrawal penalties for the durable Cluster Study process consistent with FERC Orders 2023 and 2023-A. • Any withdrawal penalty that applies to the initial Phase 1 Study should be relatively low. Customer need to gain insight into the interconnection costs associated with potential projects, no matter how "ready" those projects might be. • Support withdrawal penalties that escalate at each stage; the deeper into the process an interconnection customer proceeds, the steeper the penalty should be if that customer withdraws (subject to the exceptions). Penalties should attach in	Thank you for your comment on when to apply a withdrawal penalty. We will consider this as we are determining our alternatives and proposal.

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		accordance with the following penalty structure if the customer withdraws during or after the identified phase and before entering the subsequent phase on the list: Phase 1 Initial Study 2 times study costs Phase 1 Restudy(ies) 5% of Network Upgrade costs Phase 2 Initial Study 5% of Network Upgrade costs Phase 2 Restudy(ies) 5% of Network Upgrade costs Facilities Study 10% of Network Upgrade costs LGIA 20% of Network Upgrade costs	
39	NIPPC and RNW Joint Comments	**GI Withdrawal Penalties** *When to Apply a Withdrawal Penalty (Exemptions)* Commenting Parties support an exemption from withdrawal penalties if subsequent studies significantly increase the customer's projected interconnection costs. A customer should not be subject to penalties if (1) the customer withdraws after receiving the most recent cluster study report and the network upgrade costs assigned to the customer have increased 25% compared to the previous cluster study report; or (2) the customer withdraws after receiving the individual Facilities Study report and the costs assigned to the customer's request have increased by more than 100% compared to costs identified in the cluster study report. Commenting Parties also support an exemption for withdrawals that do not materially impact the cost or timing of projects remaining in the cluster. In thinking through the potential exemptions, Commenting Parties also note that there should be some accountability and incentives for BPA to complete its interconnection studies in a timely fashion.	Thank you for your comment on exceptions. We will consider this as we are determining our alternatives and proposal.

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40	NIPPC and RNW Joint Comments	**GI Withdrawal Penalties** *BPA Use of Penalty Funds* Consistent with FERC Orders 2023 and 2023-A, penalty funds should first be applied to fund studies and restudies in the same cluster as the withdrawing customer. If penalty funds remain after using those funds to offset study costs for those remaining in the cluster, penalties collected should be applied to offset the incremental cost increases to other customers remaining in the cluster study for network upgrade costs that the withdrawals caused, including incremental financial security requirements that are associated with higher network upgrade costs.	Thank you for your comment. We will consider this as we are determining our alternatives and proposal.
41	NIPPC and RNW Joint Comments	**GI Withdrawal Penalties** *Alternatives to Withdrawal Penalties* Commenting Parties do not have other suggestions for mechanisms that would prevent the need for restudies as effectively as withdrawal penalties. We recognize that withdrawal penalties will not completely eliminate the need for restudies. Some customers will enter the interconnection cluster study process in good faith, but ultimately need to withdraw for any number of potential valid reasons. The withdrawal penalties will mitigate the cost shifts and other impacts to the customers remaining in the interconnection process.	Thank you for your comment. We will consider this as we are determining our alternatives and proposal.
42	NIPPC and RNW Joint Comments	**GI Reform – Affected Systems** When BPA is the affected system, Commenting Parties encourage BPA to comply with the Order 2023/Order 2023-A timelines for completing Affected System Studies with its neighbors. The Affected System Studies that BPA must undertake for its neighbors are just as important for the region as the studies BPA undertakes directly. To the extent possible, BPA should conduct Affected System Studies for its neighbors independently and in parallel with its interconnection cluster study processes. Orders 2023 and 2023-A require all the investor-owned utilities in the region to adopt a cluster study process for interconnection requests. Commenting Parties note that BPA's neighboring transmission providers – at least the ones subject to FERC jurisdiction – will need to comply with the Order 2023/Order	BPA staff will address this comment in its presentation at the June 26th BP/TC-26 workshop.

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		2023-A timelines when BPA identifies them as an affected system. BPA should make every effort to deliver its own Affected System Studies on the same timeline.	
43	NIPPC and RNW Joint Comments	**GI Reform – Affected Systems** Commenting Parties also encourage BPA to coordinate and collaborate with its neighbors to develop a regional process to complete Affected System Studies. The schedule and timelines for interconnection cluster studies are known well in advance. It may become obvious in the early stages of a cluster study that a neighbor may be an affected system. Ideally, a formal request for an Affected System Study is not a surprise but rather a confirmation of earlier informal information exchanges between the transmission providers on the potential need to conduct an Affected System Study. As the region gains experience with cluster studies for interconnections, it may be appropriate to align the timing of interconnection cluster studies across the region to achieve efficiencies in Affected System Studies.	BPA staff will address this comment in its presentation at the June 26th BP/TC-26 workshop.
44	NIPPC and RNW Joint Comments	**GI Reform – Affected Systems** Affected System Study processes and timelines should be transparent. Commenting Parties suggest that when BPA is asked to conduct an Affected System Study, it should provide the transmission provider and the transmission provider's customer(s) with the estimated timeline to complete the study, as well as regular updates on progress.	BPA staff will address this comment in its presentation at the June 26th BP/TC-26 workshop.
45	NIPPC and RNW Joint Comments	**GI Reform – LGIA** Commenting Parties agree that BPA should review and propose edits to the LGIA consistent with the TC-25 settlement.	Thank you for your comment.
46	Avangrid	**ACS Rate for ESDs** Avangrid applauds Bonneville's proactive thinking but is hesitant to spend time musing over hypothetical problems that may or may not come into fruition during this rate period (or ever) when setting a new rate based on actual numbers would be an exponentially better approach. As a threshold matter, Bonneville sells its power at cost-based rates and the agency has yet to incur any costs to base the new rate on. Moreover, Avangrid is	Thank you for your comments. BPA staff will consider them as we continue to evaluate the alternatives. We will address comments in further detail and present the staff proposal (steps 5-6) at the August 27-28 BP/TC-26 workshop.

Row #	Stakeholder	Comment	BPA Staff Response
		struggling even conceptually to see these new interconnection requests for storage as a likely balancing problem for the agency. Although Avangrid acknowledges that Bonneville must stand ready to serve batteries that in theory could charge (or discharge) quickly at inopportune times, it is hard to imagine scenarios where a battery owner would choose to go against market signals to charge, discharge at inopportune times. Normally speaking, it seems like the vast amount of charging is going to happen when prices are low (and their capacity would be welcome) and the vast amount of discharging will happen when prices are high (and the capacity would be welcome). Because Bonneville does not have any recommendations to capture diversity benefits, e.g., crediting batteries that are helping the agency attain load-resource balance, Avangrid believes a storage capacity rate is not yet ripe for consideration. If Bonneville decides to develop a new capacity rate for storage devices, which it should not, Avangrid asks that Bonneville review in detail the pilot program referenced at the April Workshop, which could potentially provide a path for avoiding the new capacity charge.	
47	Avangrid	**GI Withdrawal Penalties** Avangrid continues to believe that withdrawal penalties are a critical component of the interconnection queue reform that ideally should have been implemented along with the TC-25 tariff changes. To that end, Avangrid recommends Bonneville add withdrawal penalties consistent with FERC's final rules. As a matter of policy, however, Bonneville should refrain from applying any TC-26 rule changes to the transition process, including withdrawal penalties, because any such changes were not transparently discussed during the TC-25 proceeding and will not be established with any level of certainty before the transition cluster request window opens next month.	Thank you for your comment. We will consider this when we evaluate the alternatives.
48	Avangrid	**GI Withdrawal Penalties** *How to Calculate a Withdrawal Penalty?* FERC's rules for calculating withdrawal (e.g., two times the study costs to 5 and then 10 percent of network upgrade costs) appear appropriate for Bonneville. Avangrid would	Thank you for your comment on how to calculate a withdrawal penalty. We will consider this as we are determining our alternatives and proposal.

Row #	Stakeholder	Comment	BPA Staff Response
		support a penalty fee that escalates throughout the GI process and looks forward to discussing the merits of any proposed details, deviations with stakeholders in future workshops.	
49	Avangrid	**GI Withdrawal Penalties** *When Should a Withdrawal Penalty Apply?* Acknowledging that Bonneville declined to implement the portions of FERC Order No. 2023 that provided public access to interconnection information, Avangrid recommends exploring with stakeholders whether there should be a penalty-free withdrawal when the first study results are provided. Without increased public access to interconnection information, submitting an interconnection request is still the only means to determine whether a proposed project can be commercially viable. If Bonneville is able to provide more information publicly later, it may be appropriate to consider removing this initial penalty free withdrawal at that time.	Thank you for your comment on when a withdrawal penalty should apply. We will consider this as we are determining our alternatives and proposal.
50	Avangrid	**GI Withdrawal Penalties** *Should There Be Exceptions to When a Penalty is Applied?* As Bonneville explained in the April Workshop, FERC's GI rules permit penalty-free withdrawal where there is either no material impact on other requests in the queue or where there has been a significant increase in the network upgrade cost estimates. Avangrid recommends following FERC's rules (e.g., a 25% increase from the prior cluster study or a 100% increase in a facilities study report) unless Bonneville's unique process provides a compelling reason to deviate, in which case Avangrid welcomes additional discussion.	Thank you for your comment on exceptions to when a withdrawal penalty is applied. We will consider this as we are determining our alternatives and proposal.

Row #	Stakeholder	Comment	BPA Staff Response
51	Avangrid	**GI Withdrawal Penalties** *Should a Penalty Apply During the Transition Process?* Strongly recommends that any mid-stream rule changes should not apply until the beginning of the next cluster study process. If Bonneville does ultimately apply withdrawal penalties to the transition cluster, Avangrid asks that the agency clarify whether there was sufficient notice of any such application during the TC-25 process (or otherwise) so that parties can understand whether Bonneville might make other "midstream" changes to its GI rules during its cluster study process...applying withdrawal penalties to the transition process should have been discussed transparently during the TC-25 process if Bonneville intended to apply them to the transition cluster after they were adopted in the BP-26 and TC-26 proceeding...Moreover, the cluster-study process outlined by FERC is intended to be an annual process, which places Bonneville's withdrawals in a different context. Bonneville's cluster study is unlikely to achieve that cadence, but also has unique aspects that equally impact the context for its withdrawals.	Thank you for your comment on when a withdrawal penalty should apply. We will consider this as we are determining our alternatives and proposal.
52	Avangrid	**GI Withdrawal Penalties** *Should a Penalty Apply During the Transition Process?* Avangrid recommends that Bonneville provide a straw proposal as soon as possible that includes clarity as to where the agency expects the transition process to be when the new tariff becomes effective to anchor this discussion. It is imperative that Bonneville set a reasonable expectation for how long the phase-one restudies will take with the agency's unique scalable-block concept, which allocates network upgrades based on capacity rather than FERC's impact based allocation. During the TC-25 proceeding, Bonneville argued that a capacity-based allocation would allow the agency to make changes more quickly when there is a withdrawal—and to mitigate impacts to others in the queue. Avangrid would like to better understand Bonneville's expectations for process timing, withdrawal impacts and exceptions before weighing in. Absent any such direction, however, Avangrid simply reiterates that Bonneville should follow FERC's rules and generally avoid mid-stream rule changes.	Thank you for your comment. In the April 24 workshop, BPA provided the transition process timeline and shared expectations around process timing. Although the shared timeline does not have specific dates, it does show the phases of the process.

Row #	Stakeholder	Comment	BPA Staff Response
53	Avangrid	**GI Withdrawal Penalties** *How Should Withdrawal Penalty Funds be Allocated?* FERC's GI rules direct that any withdrawal penalties be allocated first to cover study costs, then to offset increased network upgrades caused by the withdrawal with any remaining amounts returned to the withdrawing customer. This policy, which was fully vetted during the FERC rulemaking appears reasonable, but Avangrid would like Bonneville to explore in greater detail in future workshops how these determinations would be made by the agency, whether there would be any transparency or ability to challenge the allocations, etc. Avangrid looks forward to hearing from Bonneville and stakeholders familiar with other cluster-study implementations.	Thank you for your comment on penalty funds allocation. We will consider this as we are determining our alternatives and proposal. As for transparency or the ability to challenge the allocations, this would be discussed more in the Business Practice process if BPA staff proposes a withdrawal penalty in BP-26 and it is finalized in the ROD.

III. Comments Received in Response to the May 22, 2024 BP/TC-26 Workshop

Row #	Stakeholder	Comment	BPA Staff Response
54	Seattle City Light	**Transmission Line Ratings – FERC Order 881 Implementation** City Light supports BPA's overall approach to implementation of FERC Order 881. City Light suggests that there would be value in BPA developing explanatory material supporting BPA's decision to not follow the pro forma language.	BPA staff will address this comment in its presentation at the July BP/TC-26 workshop.
55	Seattle City Light	**ROFR Queue Management** City Light supports BPA's Alternative 2 to change the Tariff to harmonize BPA's practices fully with the Tariff.	Thank you for supporting Bonneville staff's recommendation of Alternative 2.
56	Seattle City Light	**Western Resource Adequacy Program (WRAP)** City Light supports continuing the WRAP principles put in place in BP-24. City Light additionally supports the BPA proposal for Above-RHWM Load and New Large Single Loads.	Thank you for your comment.
57	Seattle City Light	**Intentional Deviation in the EIM** City Light suggests BPA continue to closely monitor the impacts of VERs scheduling off forecasts and consider how any future policy changes may cause cost shifts between customer groups.	Thank you for your comment. BPA staff will continue to monitor impacts of VER scheduling in the BPA BA.
58	Snohomish PUD	**ROFR Queue Management** Snohomish supports BPA's "Alternative 2" proposal to change the language of Section 2.2(a) of BPA's Tariff to align with BPA's existing process to offer ROFR to customers who request at least five years of service...Snohomish concurs that the process to complete studies and contract approvals are inherently lengthy. Modification of Bonneville's tariff will continue to allow BPA to accommodate new transmission service needs without procedural setbacks and will provide significant benefits and prevent significant harm when compared to the pro forma alternative.	Thank you for supporting Bonneville staff's recommendation of Alternative 2.
59	Portland General Electric	**Transmission Line Ratings – FERC Order 881 Implementation** Portland General Electric Company ("PGE") hereby respectfully submits that Bonneville Power Administration ("BPA") should provide TTC values in compliance with FERC Order No. 881 ("Order") for jointly owned transmission paths where BPA is the path operator...On May 22, BPA explained that it does not plan on providing TTC values that are compliant with Order 881, which would put BPA's path ratings out of line with the rest of the	BPA staff will address this comment in its presentation at the July BP/TC-26 workshop.

Row #	Stakeholder	Comment	BPA Staff Response
		Northwest. PGE requests that BPA provide forecasted hourly AARs for the required (and now industry standard) 240 hours into the future. As the path operator, BPA calculates the TTC for the jointly owned paths and provides PGE its share of the TTC for All Lines in Service (ALIS) and outage conditions as part of the operating agreements for such paths. BPA's disposition towards complying with the 240 hours of hourly Ambient Adjusted TTC Ratings will impact PGE's ability to provide its transmission customers the hourly transmission capacity of its share of the jointly owned transmission scheduling paths operated by BPA.	
60	NIPPC and RNW Joint Comments	**Transmission Line Ratings – FERC Order 881 Implementation** BPA staff...proposes that BPA will not comply with Order 881's requirement to calculate and post separate daytime and nighttime transmission line ratings. BPA has a framework to determine the circumstances in which it will propose tariff provisions that deviate from the FERC pro forma Open Access Transmission Tariff ("OATT"). BPA staff, however, has not presented any analysis that explains to customers why it is appropriate for BPA to deviate from FERC's Order 881 on this issue. FERC conducted a rulemaking process and upon full consideration of the record, FERC determined the requirements of Order 881 were necessary to ensure accurate line ratings and avoid rates that are unjust and unreasonable. Based on the information presented to date, it is not clear why BPA staff has come to a different conclusion than FERC on the usefulness of separate daytime and nighttime transmission line ratings.	BPA staff will address this comment in its presentation at the July BP/TC-26 workshop.
61	NIPPC and RNW Joint Comments	**Transmission Line Ratings – FERC Order 881 Implementation** Staff also seeks to insert additional language to the definition of "Ambient-Adjusted Rating" proposed by FERC. On the one hand, it seems reasonable that BPA would "evaluat(e) the need to curtail paths or develop(e) Operating Plans to prevent/mitigate an (sic) System Operating Limit (SOL) exceedance on the network." On the other hand, that additional language does not seem to be appropriate within the definition of an Ambient Adjusted Rating. Rather, it seems to be an ongoing action that BPA would take to ensure the reliability of its system and not limited to any requirement to develop or post ambient	BPA staff will address this comment in its presentation at the July BP/TC-26 workshop.

Row #	Stakeholder	Comment	BPA Staff Response
		adjusted line ratings. Moreover, BPA has not provided any analysis under its OATT deviation framework that explains how this additional language meets that standard.	
62	NIPPC and RNW Joint Comments	**Transmission Line Ratings – FERC Order 881 Implementation** Commenting Parties also note that BPA's neighboring transmission systems will be complying with Order 881 and posting daytime and nighttime Ambient Adjusted Ratings for their transmission facilities connecting to BPA's network. Commenting Parties request further explanation from BPA staff about whether its proposal to deviate from the language of Order 881 will create any unnecessary seams with its adjoining transmission providers. At this time, Commenting Parties do not have a formal recommendation as to BPA's proposed deviations from Order 881, but simply seek to better understand BPA's reasoning for proposing them.	BPA staff will address this comment in its presentation at the July BP/TC-26 workshop.
63	NIPPC and RNW Joint Comments	**ROFR Queue Management** Commenting Parties support Alternative 2. We agree that transmission customers who seek transmission service for five years or more should not lose their right of first refusal due to delays in BPA offering the requested service. The defining feature of rollover rights should be that the customer initially requested service for five years or more; if BPA experiences delays to the point that the term of service offered to a customer is less than the five years of service the customer requested, then rollover rights should still apply.	Thank you for supporting Bonneville staff's recommendation of Alternative 2.
64	NIPPC and RNW Joint Comments	**Attachment A – Conditional Firm Service Agreement Exhibit** Commenting Parties support Alternative 2. We agree that the Conditional Firm Service Agreement should be included in Attachment A along with other form Service Agreements.	Thank you for supporting Bonneville staff's recommendation of Alternative 2.
65	NIPPC and RNW Joint Comments	**Section 4 Update to Align with Attachment C (ATC)** Commenting Parties support Alternative 2. Attachment C of the BPA tariff documents BPA's methodology for calculating Available Transfer Capability ("ATC") and Total Transfer Capability ("TTC"). BPA recently updated Attachment C as part of the TC-24 tariff revision process. Commenting Parties agree that BPA should conform Section 4 of its OATT to reflect BPA's practice as documented in Attachment C.	Thank you for supporting Bonneville staff's recommendation of Alternative 2.

Row #	Stakeholder	Comment	BPA Staff Response
66	NIPPC and RNW Joint Comments	**Intentional Deviation in the EIM** See complete comment submitted in response to the May 22 workshop, which is posted in the Customer Comments section on the BP-26 Rate Case webpage.	See the BPA staff response below on page 26-27.

Last Updated: October 10, 2024

The following is BPA staff's response to comments on the topic of Intentional Deviation in the EIM submitted by NIPPC and RNW following the May 22 BP/TC-26 Workshop. See comment on row 66.

NIPPC and RNW expressed concerns regarding the Intentional Deviation (ID) rate. Specifically, NIPPC and RNW argue that the ID should not apply to any scheduling or bidding behavior allowed by the CAISO EIM Tariff. BPA disagrees that ID is unnecessary in the EIM.

ID exists to incentivize proper scheduling behavior and avoid scheduling error that are inconsistent with BPA's rate case assumptions. The Balancing Reserve Quantity Forecast methodology sets capacity requirements based on VER error measured relative to BPA's VER forecast. Use of a less accurate schedule than BPA's VER forecast is inconsistent with BPA's rate case assumptions and may make the amount of reserves BPA has planned to provide insufficient. Whether in or out of the EIM, VER customers will continue to independently submit tags to establish their schedule, and use of a less accurate schedule will continue to pose the same issues. This is true of both EIM Participating and Non-Participating VER Resources.

Ensuring accurate scheduling is critical to BPA's operation of a reliable Balancing Authority Area (BAA), as the EIM does not address the BA's responsibility. Inaccurate scheduling by VERs in the EIM continues to impact the BAA by: (1) consuming available INC/DEC in the BAA and the EIM (both Regulation and Non-Regulation), (2) consuming available Transmission donations to the EIM; and (3) directly impacting the ability of BPA to maintain reliability during Resource Sufficiency Test failures, power-balance constraints, and periods where BPA must pause/exit EIM participation.

The Energy Imbalance Market does not sufficiently incentivize accurate scheduling through price signals. As an energy only market, the EIM fails to capture the capacity costs associated with providing that energy. The capacity of energy that is needed before the operating hour is to pass EIM Resource Sufficiency Tests (hourly test required for participation in the EIM). During the operating hour, the real-time use of energy is what is being captured in the EIM price signals.

ID prevents impacts to the BPA BA (as the EIM Entity) to the EIM Resource Sufficiency Tests from inaccurate scheduling. These include impacts to both the Capacity and Flex Ramp Tests where the difference in schedule to forecast difference must be made up with INC/DEC energy Bids with adequate ramping ability.

BPA realizes that VERs that become EIM Participating Resources may receive an instructed dispatch from the Market Operator that alters a VER's output. The ID rate contains provisions excluding any five-minute interval during which a VER Participating Resource was economically dispatched by the EIM. Because an economic dispatch from the EIM would alter the natural output of the VER Participating Resource, it may skew the accuracy of the schedule compared to BPA's VER forecast, making assessment of ID inappropriate.

NIPPC and RNW also assert that the CAISO wind forecast is more accurate because it provides a forecast for each 15-minute interval rather than the single hourly value that the BPA forecast provides. The logistics of how the EIM RS Tests are applied to EIM Entities and CAISO do not allow for an even comparison to be done on this statement. CAISO subjects themselves to a different standard than any other EIM Entity by leveraging their DA market within the CAISO BAA to exempt themselves from the Balancing Test. As an EIM Entity, BPA is subject to the Balancing Test, which compares hourly resource schedules to hourly load forecasts. While a VER is allowed to use 15-min scheduling in the BPA BAA, the Balancing Test requires they provide an hourly Base Schedule prior to doing so. BPA has opted not to use the CAISO hourly wind forecast because BPA has found that the BPA hourly forecast is more accurate. In addition, the VERBS rate is based on generators scheduling to the BPA forecast, as such, use of a different forecast would be at odds with rate case assumptions. VERs may use a different forecast, but if the forecast is less accurate than the BPA forecast, the VERs will be subject to ID. If a VER Participating Resource desires to use the CAISO hourly wind forecast, it will likely need to work with BPA and CAISO to integrate a separate forecast for the BAA and pay the CAISO for the use of the forecast. However, the VER Participating Resources will still be in BPA's BAA and will need reserve capacity provided by BPA. As a result, BPA will also need to adopt a separate rate that incorporates the impacts of using the CAISO forecast on BPA's reserve requirements, like the previous use of scheduling elections in the VERBS rate. This will likely result in a higher VERBS rate, and ID will likely still be needed to ensure a VER schedules to the CAISO forecast. Inaccurate scheduling, whether to BPA's forecast or another forecast, has the same effect on the BAA and must be incentivized.

NIPPC and RNW also assert that "a customer who schedules to a forecast different from the CAISO VER Forecast and does not deliver its Expected Energy to the market is subject to an Under/Over Delivery Charge." If, as NIPPC and RNW assert, a customer scheduled to the CAISO VER Forecast, it "would not be exposed to the Under/Over Delivery Charge and would rely far less on BPA to provide balancing reserves to serve its schedule." BPA is unaware of any Under/Over Delivery Charge that applies to customers in the EIM. The CASIO Tariff has sections that apply to entities within its own BAA and to entities within the EIM. While there is an Under/Over Delivery Charge under section 11.31 of the CAISO Tariff (a non-EIM section of the CASIO Tariff), the EIM is subject to Section 29 of the CAISO Tariff unless specified. Section 29.11(a) of the CAISO Tariff provides:

> Section 29.11, rather than Section 11, shall apply to the CAISO Settlement with EIM Entity Scheduling Coordinators, EIM Sub-Entity Scheduling Coordinators, and EIM Participating Resource Scheduling Coordinators, except as otherwise provided, but not to other Scheduling Coordinators.

Section 29.11 of the CAISO Tariff does not have an Under/Over Delivery Charge that applies.

NIPPC and RNW also comment that BPA should "develop a decision matrix similar to the one that BPA applies when it considers tariff deviations from the pro forma OATT against which to measure this and future extra-market penalties." Adopting such a framework is not appropriate with respect to rates. There is no pro forma rate structure against which BPA can compare itself to. Under section 7(a)(1) of the Northwest Power Act, BPA is required to set rates to recover its costs. The ID and similar rates are intended to ensure cost recovery by establishing incentives to keep customer behaviors in line with rate case assumptions. However, as explained previously, the EIM does not sufficiently incentivize accurate scheduling. If changing landscapes, such as a Day-Ahead Market, provide enough incentive for customers to schedule accurately, then BPA and customers can reassess whether ID, or any other rate, remains necessary.

IV. Comments Received in Response to the June 26, 2024 BP/TC-26 Workshop

Row #	Stakeholder	Comment	BPA Staff Response
67	Seattle City Light	**Non-EIM Balancing** City Light supports the proposed Option 2: General Language and agrees that this should include language regarding recovering imbalance costs not assessed through EIM. City Light suggests that the Locational Marginal Prices (LMP) should be used for imbalance cost recovery if available. If an LMP is not available, using the EIM Load Aggregation Point (ELAP) should be used for imbalance cost recovery. City Light additionally suggests that BPA include an appeal process for Non-EIM Balancing charges like the UIC appeal process.	Thank you for your comment. BPA will consider the suggestion of using the LMP first and the ELAP as a backup when developing its recommendation. Appeal language specific to this rate isn't necessary as customers may use the existing Billing Dispute Procedures Business Practice. BPA only has rate-specific waiver processes for rates that are intended to incent certain behaviors, such as the UIC, Failure to Comply, Persistent Deviation, and Intentional Deviation. The proposed rate is intended to recover BPA's actual costs.
68	Seattle City Light	**GI Withdrawal Penalties** See complete comment submitted in response to the June 26 workshop, which is posted in the Customer Comments section on the BP-26 Rate Case webpage.	Thank you for your comment. We will consider your comments as we develop a staff recommendation and present at the August workshop.
69	Seattle City Light	**WA Cap and Invest Program Charge** City Light supports BPA's proposal to preserve the BP-24 language and principles regarding the WA Cap and Invest Program Charge.	Thank you for your comment.
70	Seattle City Light	**GI Reform – Affected System Studies** City Light requests that BPA commit to holding a customer workshop addressing GI Affected Systems Studies by March 1st, 2026.	For the TC-26 tariff proceeding, BPA is focusing on following its commitments made in the TC-25 Settlement Agreement. BPA intends to continue to evaluate FERC Order 2023 and 2023-A to identify additional changes that may be necessary to BPA's Tariff, including changes related to Affected System Studies in the next tariff proceeding. As an interim step, BPA will be working to update its implementation of Affected System Studies through a business practice. BPA values stakeholder input and intends to undertake stakeholder engagement around the Affected Systems topic through BPA's Business Practice Process.

Row #	Stakeholder	Comment	BPA Staff Response
71	Avangrid	**Non-EIM Balancing** Avangrid appreciates Bonneville's adherence to cost causation principles but is not able to recommend one option over the other given the amount of information presented to date, and is not convinced that this issue would be best remedied with a new rate schedule. It is not yet clear how customers would be made aware that they were causing these charges or whether passing the charges along to generators is appropriate in all circumstances. Additionally, Avangrid agrees with comments from stakeholders at the June Workshop that given this lack of understanding and transparency, Bonneville's proposed alternatives would benefit from some type of appeal process. Additionally, as noted during the discussion, Bonneville's proposed solutions may have been mooted by the agency's recently announced leaning to join the SPP day-ahead market, which would necessarily limit the amount of EIM mismatches the agency could expect to incur going forward under the TC-26 tariff. Should Bonneville proceed with a new rate schedule, Avangrid recommends the agency identify a process or mechanism to ensure that the agency isn't over (or under) collecting in situations where improved data exchanges or system alignment would avoid incurring any such EIM imbalance charges.	Thank you for your comment. BPA will continue to communicate with customers when BPA identifies correctable customer behavior that may be causing the imbalance. In addition, appeal language specific to this rate isn't necessary as customers may use the existing Billing Dispute Procedures Business Practice. BPA only has rate-specific waiver processes for rates that are intended to incent certain behaviors, such as the UIC, Failure to Comply, Persistent Deviation, and Intentional Deviation. The proposed rate to recover imbalance costs is intended only for cost recovery. Finally, BPA did issue a recommendation in April that the agency join SPP Markets+, but a final decision has yet to be announced so it is premature to conclude whether this issue is moot. Furthermore, any time spent in the EIM without an additional rate will result in under recovery of costs. Implementation of this rate will include adjustments to the EIM Detailed Data File issued, which will provide a level of transparency sufficient to ensure that the agency isn't over or under collecting.
72	Avangrid	**GI Withdrawal Penalties** Avangrid continues to believe that withdrawal penalties are a critical component of FERC's interconnection cluster study process and sees little reason to deviate from FERC rules. At the June Workshop, Bonneville described possible alternatives to implement withdrawal penalties at seven unique withdrawal stages throughout the cluster study process,7 proposed unique exceptions that would permit a penalty-free withdrawal,8 and noted that eligibility and allocation would be discussed in future workshops.9 Of the alternatives presented, Avangrid would support Alternative 2 because it more closely aligns with FERC's rule.10 Avangrid looks forward to future discussions with Bonneville and stakeholders on the merits of the various components to a potential withdrawal penalty. Given the timing of a potential implementation of withdrawal penalties during the current Transition Cluster, Avangrid reiterates that a penalty-free withdrawal during the Transitional Cluster is appropriate. Assuming the withdrawal penalties will be effective	Thank you for your comment. We will consider your comments as we develop a staff recommendation and present at the August workshop.

Row #	Stakeholder	Comment	BPA Staff Response
		October 1, 2025, however, and acknowledging that the first GI decision point after that date remains uncertain, Avangrid also believes that applying an Alternative 2 withdrawal penalty during a Phase 1 restudy (or any decision point after the TC-26 tariff effective date) in the Transitional Cluster could also be appropriate.11 Avangrid believes the key to establishing good policy, and to avoiding retroactive ratemaking, is providing GI customers sufficient time along with costs that are certain to weigh the costs and risks and make reasonable business decisions before advancing an interconnection request into the next study and/or restudy.	
73	Savion	**GI Withdrawal Penalties** See complete comment submitted in response to the June 26 workshop, which is posted in the Customer Comments section on the BP-26 Rate Case webpage. Savion prefers BPA's Alternative 2 due to its cost-causation principles found in the "% of Allocated Costs" criteria. If Alternative 2 were also paired with an up-front gating mechanism comparable to the Volumetric Price Escalator proposed in Savion's May 9th presentation, we believe BPA would have a very strong GI study framework that will thwart the vast majority of unproven GI study requests while standing up to the scrutiny of GI customers seeking just and reasonable treatment.	Thank you for your comment. We will consider your comments as we develop a staff recommendation and present at the August workshop.
74	NIPPC and RNW Joint Comments	**Non-EIM Balancing** NIPPC and RNW suggest that a decision-making framework and further exploration of alternatives are warranted in evaluating the best path forward on this issue. While we generally agree with the principle that customers who create imbalance should pay for the imbalance they create, we do not have a clear enough grasp of the various permutations of this issue, and we have some concerns with BPA's proposed solutions as they relate to the two specific examples discussed at the workshop. As we presented in our customer-led workshop on June 13, NIPPC and RNW suggest that BPA should rely primarily on market signals and market structures to manage customer behavior and recover costs in preference to extra-market rate and penalty mechanisms. Only when price signals and market structures are inadequate should BPA pursue extra-market options for ensuring appropriate cost recovery. It is not clear in this instance that	Thank you for your comment. BPA does not believe adopting a framework for extra-market charges is appropriate with respect to rates. BPA is required to set rates to recover its costs, and the proposed rate is intended to recover actual costs incurred. BPA has and will continue to follow the Rate Case process detailed in Section 7(i) of the Northwest Power Act to set rates. In addition, the expectation that any such mechanism would not be limited to charging customers but would also allocate credits for imbalance energy to customers when appropriate is correct. Further, appeal language specific to this rate isn't required as any need for an appeal will fall under BPA's Billing Dispute Procedures Business Practice. BPA will continue to communicate with customers when BPA identifies correctable customer behavior that may be causing

Row #	Stakeholder	Comment	BPA Staff Response
		price signals and market structures – including the California Independent System Operator's ("CAISO") market monitoring unit – are insufficient at addressing the issues raised in BPA's presentation. NIPPC and RNW again encourage BPA to adopt a decision-making framework to apply whenever it considers extra-market penalties or restrictions, and to apply that framework to the questions raised in the Non-EIM Balancing presentation. If BPA moves forward with an out-of-market imbalance settlement mechanism, NIPPC and RNW expect that any such mechanism would not be limited to charging customers but would also allocate credits for imbalance energy to customers when appropriate. NIPPC and RNW also agree with the suggestion from WPAG at the workshop that any out-of-market settlement mechanism for imbalance charges (or credits) should include a dispute resolution mechanism for customers to challenge BPA's allocations. We note that generation imbalance customers themselves have an easy option to mitigate the "Base Schedule Mismatch" scenario that BPA described. In short, customers can ensure that the pMax on file with the CAISO accurately represents their units' maximum output. If balancing service customers will not take that simple step, then NIPPC and RNW support further exploring BPA's proposal to establish a mechanism to recover the costs of imbalance energy from customers who create imbalances on BPA's system but are not charged for those imbalances in the market. More difficult is the "Outage Sync" issue. In these situations, BPA described circumstances where the market communication mechanisms are coordinated poorly and customers – through no fault of their own – may receive an imbalance charge or credit through the market that does not accurately reflect a given customer's actual imbalance for an interval. In these instances, the customer is not responsible for creating the imbalance, but BPA nonetheless seeks to impose imbalance charges on the customer. Ideally, BPA would continue to work with CAISO to ensure that communications between BPA, CAISO, and units recovering from an outage would be better coordinated. We are concerned that an extra-market settlement mechanism will result in BPA deprioritizing efforts to work with	the imbalance. Finally, a rate to recover Non-EIM Balancing costs does not preclude BPA from working with CAISO to better optimize the EIM. If sufficient adjustments are made such that charges under a Non-EIM Balancing Rate are reduced to a minimum, then the rate may not be necessary.

Row #	Stakeholder	Comment	BPA Staff Response
		CAISO to improve the coordination of their communications to customers and that once it is adopted, BPA will simply look to the out-of-market settlement to resolve the issue after the fact. We encourage BPA to prioritize system improvements and coordination over imposing a charge on customers for "Outage Sync" issues.	
75	NIPPC and RNW Joint Comments	**GI Withdrawal Penalties** See complete comment submitted in response to the June 26 workshop, which is posted in the customer Comments section on the [BP-26 Rate Case webpage.](BP-26 Rate Case webpage) In summary, we encourage BPA to adhere to FERC Order 2023 and 2023-A as closely as possible, while recognizing that BPA must also implement tariff changes that are consistent with both the spirit and letter of the TC-25 Settlement Agreement. While we appreciate BPA staff's efforts in providing customers with a range of alternatives to consider, NIPPC and RNW believe that the recommendations set forth above effectively conform Order 2023 and 2023-A to the TC-25 Settlement Agreement. We look forward to reviewing a proposal from BPA and working with BPA and other customers to develop a more refined withdrawal penalty mechanism.	Thank you for your comment. We will consider your comments as we develop a staff recommendation and present at the August workshop.
76	NIPPC and RNW Joint Comments	**GI Reform – LGIA** Please provide an update on BPA's timeline to implement the reforms of FERC Order 845 allowing customers to self-build interconnection facilities. NIPPC and RNW note that BPA has already adopted the Order 845 self-build option in its tariff, but has yet to implement that functionality for transmission customers.	BPA staff will address this comment in its presentation at the July BP/TC-26 workshop.
77	NIPPC and RNW Joint Comments	**GI Reform – Affected System Studies** NIPPC and RNW are disappointed with BPA's proposal to not evaluate or consider Affected System Studies as part of TC-26. BPA has limited windows to consider changes to its tariff to conform with new FERC requirements. While BPA may generally not be subject to FERC jurisdiction on the terms and conditions of transmission service, Affected System Studies are a critical component of ensuring that the region maintains a safe and reliable grid as that grid must expand to incorporate new generation needed to meet state energy policies. BPA's neighboring transmission operators will rely on BPA's timely completing of Affected System Studies. BPA's suggestion that it will maintain its status quo in the face of a significant reform which FERC has determined is necessary to ensure just and reasonable	See response to comment #70 above.

Row #	Stakeholder	Comment	BPA Staff Response
		transmission rates is inappropriate. Accordingly, we encourage BPA to reconsider this decision. BPA should work closely now with its neighboring transmission providers to develop coordinated processes, timelines, and expectations for the completion of Affected System Studies so that the long lead times for necessary transmission upgrades are not further extended because of delays in completing these studies.	
78	NIPPC and RNW Joint Comments	**Attachment K – Regional Planning** NIPPC and RNW are also disappointed with BPA's update on regional planning and what appears to be a largely passive approach as NorthernGrid considers how to comply with FERC Order 1920. Order 1920 represents a significant reform of the existing regional transmission planning processes and cost allocation. BPA simply indicates that it is monitoring Order 1920 and the compliance plans of jurisdictional utilities in the region and will report developments to customers in the future. As the major transmission provider in the region, BPA must take a leadership role in every process that explores transmission expansion. Outside of NorthernGrid planning, BPA has its own processes – the Transmission Service Request Study and Expansion Process ("TSEP") and the Bifurcated Commercial Model ("BCM") – that it uses for transmission planning on its system and considering how to recover the costs of transmission expansion. There is an opportunity now – which will close once NorthernGrid's compliance filing is complete – for BPA to influence the NorthernGrid process to ensure that the results of studies coming out of NorthernGrid meet the needs of BPA as it considers how transmission expansion projects identified in TSEP should be evaluated as regional projects for purposes of the BCM. Likewise, BPA has a limited opportunity to influence how the NorthernGrid process considers and incorporates the results of TSEP in the Order 1000/1920 regional planning process. Our overall sense is that BPA considers TSEP/BCM and Order 1000/1920 planning and cost allocation as separate silos. NIPPC and RNW urge BPA to consider how those planning processes can inform and build upon each other instead of proceeding independently. We suggest that developing this coordination between TSEP/BCM and NorthernGrid must be happening now while transmission providers in the region are developing the compliance	Thank you for your comment. As explained in the June workshop, Bonneville will actively and collaboratively work with NorthernGrid members to adopt the reforms in a manner that is consistent with Bonneville's legal authorities and with the structure and governance already in place at NorthernGrid, and Bonneville will participate in this effort during the 10- to 12-month timeline prescribed by the order. Since there are aspects of Order No. 1920 that will impact jurisdictional and non-jurisdictional members differently, Bonneville will work to respect those differences while supporting the elements of the order that non-jurisdictional entities are able to adopt and continuing to promote NorthernGrid's planning process.

Row #	Stakeholder	Comment	BPA Staff Response

		strategy for NorthernGrid; BPA's customers cannot afford for BPA to wait and see what regional IOUs propose for NorthernGrid. Accordingly, we urge BPA to meet its responsibilities to the region head on and be actively involved in NorthernGrid's compliance process. More specifically, we recommend that BPA actively engage in NorthernGrid members' compliance discussions and advocate that NorthernGrid incorporate mechanisms to develop transmission plans and a cost allocation structure that includes the following:
		
		• Adopts the "seven benefits" and scenario planning as part of NorthernGrid
		• compliance with Order 1920;
		• Incorporates scenario planning on 10- and 20-year timeframes;
		• Independently considers state policy requirements and other drivers of
		• demand for transmission service;
		• Considers a wide range of transmission portfolio future scenarios,
		• including co-optimizing storage and other technologies, in the 10- and 20-year planning timeframes, in order to identify "no regrets" or "least regrets" portfolios;
		• Develops a cost-allocation process consistent with the requirements of Order 1920 and that:
		    ○ Incorporates formal state engagement in the NorthernGrid process;
		    ○ Considers joint venture and partnership opportunities that rely on private capital and private projects to relieve BPA of initial development, construction, or subscription risk; and
		    ○ Considers whether investor-owned utilities can and would be willing to serve in some form as backstop subscribers for transmission upgrades identified in the NorthernGrid planning process.	

Row #	Stakeholder	Comment	BPA Staff Response
79	Snohomish PUD	**WA Cap and Invest Program Charge** Snohomish is generally supportive of BPA's proposal to carry forward the approach from BP-24. In light of uncertainty raised by Washington Initiative 2117, which would repeal the Cap-and-Invest Program, it does not make sense for BPA to make a decision on becoming the First Jurisdictional Deliverer (FJD) ahead of the BP-26 rate case. It is therefore appropriate to preserve optionality for BPA to become the FJD during the BP-26 rate period by including a Cap-and-Invest Program Charge in the BP-26 Power Rates. Snohomish also supports BPA's commitment to conduct a public process prior to any such decision to become the FJD, as there are several implications for BPA and its power customers. Specifically, Snohomish recommends that the public process include consideration of more details around the required transfer of no-cost allowances to BPA. • **<u>Volume of no-cost allowances to be transferred:</u>** Utilities are allocated no-cost allowances based on utility forecasts of load and resources, while CCA compliance is based on actual emissions, which may differ from the allocated allowances. In addition, a utility's forecasted purchases from BPA may only comprise a portion of its allocated allowances. Will the number of allowances that a utility must transfer to BPA be based on the allocation of no-cost allowances associated with the utility's purchases from BPA, a BPA forecast of sales to the utility, actual sales to the utility, or some other measure? How would any backward-looking adjustment to a utility's allocation be addressed? • **<u>Timing:</u>** How will the timing of the determination of allowances owed to BPA and the actual transfer of allowances fit into Ecology's timelines around allowance allocation and compliance? While Snohomish believes these are important details to be addressed, they do not need to be determined now and can be worked through during the public process prior to BPA making an FJD determination.	Thank you for your comment. BPA appreciates Snohomish sharing thoughts on considerations for a future public process. As Snohomish indicates, those aspects do not need to be determined at this time. BPA will consider Snohomish's comments, as well as other input, during any future public process regarding whether BPA will opt to be the FJD for Washington's cap-and-invest program.

V. Comments Received in Response to the July 30, 2024 BP/TC-26 Workshop

Row #	Stakeholder	Comment	BPA Staff Response
80	Seattle City Light	**Network Loss Factors** City Light supports the staff recommendation to maintain the current two season loss factors determined by the current loss factor study methodology.	Thank you for your comment.
81	Seattle City Light	**ROFR Queue Management** City Light supports the staff recommendation to change the tariff language regarding ROFR for alignment with BPA practices.	Thank you for your comment.
82	Seattle City Light	**Transmission Line Ratings** City Light thanks BPA for outlining the rationale behind the deviations from Order 881 and supports BPA's planned implementation.	Thank you for your comment.
83	Seattle City Light	**GI Reform – LGIA** City Light supports BPA proposed changes to the LGIA including the updated definitions.	Thank you for your comment.
84	Seattle City Light	**EIM Charge Codes** City Light generally supports BPA's approach to follow cost causation principles and industry best practices.	Thank you for your comment.
85	Seattle City Light	**Persistent Deviation** City Light supports BPA staff recommendation to change the tariff language to provide greater clarity regarding Persistent Deviation charges. City Light additionally supports BPA following cost causation principles regarding applying charges to entities in instances where actions cause a cost to BPA.	Thank you for your comment.
86	Seattle City Light	**New Technology Pilot** City Light supports the BPA staff recommendation proposing more general language to allow all new technologies to be included in the technology pilot program.	Thank you for your comment.
87	Portland General Electric	**Transmission Line Ratings** Bonneville Power Administration ("BPA") should reconsider deviating from the Federal Energy Regulatory Commission's ("FERC") Order No. 881 ("Order"), align with what will be standard utility practice following implementation of the Order, and provide ambient adjusted Total Transfer Capability ("TTC") values in compliance with the Order for jointly	BPA appreciates PGE's comment. For the reasons stated in the July 30 BP/TC-26 workshop, BPA is proposing not to adopt the provision of Order 881 to provide ambient adjusted TTC values. BPA is currently coordinating with PGE on the operation of jointly-owned facilities outside of the Tariff process.

Row #	Stakeholder	Comment	BPA Staff Response
		owned transmission paths where BPA is the path operator. While PGE appreciates the opportunity to submit comments to BPA, it is important to note that in this proceeding, PGE is commenting not as a customer of BPA taking service under BPA's Tariff, but as a co-owner of certain transmission paths in the Northwest that BPA operates pursuant to longstanding contractual obligations. PGE reiterates that as BPA is the path operator of the jointly owned transmission paths with PGE and currently provides TTC values for those jointly owned transmission lines, BPA's actions as the operator of these paths directly impacts PGE's compliance with the Order. On July 30, BPA explained that after considering PGE's June 6 comments in this proceeding, BPA will not provide TTC values that are ambient adjusted and compliant with the Order, which would put BPA's path ratings out of line with the rest of the Northwest and the industry generally. PGE again requests that BPA provide the required and industry standard forecasted hourly ambient adjusted ratings 240 hours into the future in accordance with standard industry practice. As the path operator, BPA calculates the TTC for the jointly owned paths and provides PGE its share of the TTC for All Lines in Service (ALIS) and outage conditions as part of the operating agreements for such paths. BPA's disposition towards complying with the Ambient Adjusted TTC Ratings will impact PGE's ability to provide its transmission customers the hourly transmission capacity of its share of the jointly owned transmission scheduling paths operated by BPA, as required by FERC.	
88	NIPPC and RNW Joint Comments	**General Comments and Requests** We recognize the significant undertaking in putting together BP/TC-26 proposals for stakeholder consideration amid other workload constraints, especially in a time of major industry change. However, as noted at the workshop, we remain concerned that we are nearing the end of the prerate case process and have yet to see proposals on several important issues, including withdrawal penalties and the option to self-build interconnection facilities. It may be worth considering adding one or more pre-rate case workshops to the schedule to allow for more collaborative discussion prior to the start of the official proceeding.	Thank you for your comments. The following are responses to the topics covered: • BPA has previously shared with customers that a September workshop will be added if necessary and it is currently our intention to do so. This workshop will provide additional opportunities for discussion and collaboration. • BPA is still determining if we will be able to provide a rate projection at the September BP/TC-26 pre-proceeding customer workshop. Any capital and expense increases

Row #	Stakeholder	Comment	BPA Staff Response
		As far as topics to cover, we request that BPA provide some initial projections regarding the proposed transmission rate increase that is expected based on updates from BPA's Integrated Program Review ("IPR") process. We seek to better understand the magnitude of the capital and expense increases announced in the IPR ahead of the formal BP/TC-26 process. Relatedly, we request that BPA provide a primer on the other inputs that impact the overall rate and explain how certain transmission rates flow through power rates. With so many new and prospective customers in the region, it would be helpful for BPA to provide this basic overview for those who are unfamiliar with BPA's system and practices. We do not anticipate that BPA would need to prepare any new material for such a presentation, but request that BPA simply provide a walkthrough to give all interested stakeholders the same foundation going into the official BP/TC-26 process. In response to BPA's July 29, 2024 "Summary of Written Comments Received and BPA Staff's Responses," we reiterate our concerns regarding BPA's proposal to not evaluate or consider Affected Systems Studies as part of TC-26. We remain concerned about the potential for significant project delays due to the delays in processing Affected Systems Studies. We encourage BPA to include this topic in a future pre-rate case workshop in order to discuss potential timelines and options for addressing this issue.	announced in the IPR will have a direct impact on the Revenue Requirement, which will be included as part of the August workshop, however, requests for additional detail about the capital and expense forecasts should be directed through the IPR process. • BPA will provide a rate primer, including how certain transmission rates flow through power rates, at the September workshop as suggested. • Regarding the comment on Affected System Studies, please see response #70 in this document for additional information on BPA's plan to address Affected System Studies.
89	NIPPC and RNW Joint Comments	**ROFR Queue Management** NIPPC and RNW support BPA Staff's proposal to conform BPA's tariff to its existing practice of awarding rollover rights to customers who request a term of service of 5 years or longer.	Thank you for your comment.
90	NIPPC and RNW Joint Comments	**GI Reform – LGIA** NIPPC and RNW note that BPA proposes to retain the existing language of LGIA Section 11.5 related to Provision of Security, which applies only when construction of network upgrades is about to begin. NIPPC and RNW also note that while BPA expressly excluded withdrawal penalties from the TC-25 process, the magnitude and other details associated with a withdrawal penalty framework are in scope for the BP/TC-26 proceeding. NIPPC and RNW are concerned that undercapitalized customers faced with withdrawal penalties may simply declare insolvency	BPA staff will address this comment in its presentation at the August 27-28 BP/TC-26 workshop.

Row #	Stakeholder	Comment	BPA Staff Response
		and walk away from paying withdrawal penalties that are intended to mitigate harm to BPA and its customers from the costs and delays associated with the withdrawal. NIPPC and RNW ask that BPA explain how it will recover the full amount of withdrawal penalties from insolvent customers in the absence of requiring customers to provide security for those amounts. NIPPC and RNW suggest that BPA consider including language in BPA's LGIA requiring a customer to provide security in an amount sufficient to cover the estimated withdrawal penalties that would accrue if the customer withdrew from the generator interconnection cluster study process. NIPPC and RNW appreciate BPA's update at the July 30 workshop that it is working to implement the reforms of FERC Order 845 allowing customers to self-build interconnection facilities. As previously noted, BPA has already adopted the Order 845 self-build option in its tariff, but has yet to implement that functionality for transmission customers. NIPPC and RNW look forward to BPA's update at the August workshop with more detail and proposed LGIA redlines on this topic.	
91	NIPPC and RNW Joint Comments	**Persistent Deviation** See complete comment submitted in response to the July 30 workshop, which is posted in the Customer Comments section on the [BP-26 Rate Case webpage].	Thank you for your comment regarding the Persistent Deviation Penalty. The scope of the proposed Persistent Deviation Penalty change is to clarify BPA's intent of the penalty and how it will be charged, not the structure or validity of the penalty. Please see BPA's previous testimony, BP-22-E-BPA-23, for the justification of the Persistent Deviation Penalty while BPA is in the EIM. BPA understands NIPPC/RNW has expressed a desire that a formal framework be adopted to evaluate whether extra-market penalties are appropriate or whether market price signals are sufficient to manage customer behavior. Please see BPA's position to this suggestion in the response to NIPPC/RNW's comment regarding the Intentional Deviation Penalty.
92	NIPPC and RNW Joint Comments	**New Technology Pilot** NIPPC and RNW applaud BPA for its efforts to expand the scope of the New Technology Pilot to incorporate newer technologies—such as wave generation and fuel cells—as well	Thank you for your comments supporting the expansion of the scope of the New Technology Pilot. The only criteria BPA has for the New Generation Technology Pilot Program is that the customer

Row #	Stakeholder	Comment	BPA Staff Response
		as new combinations of existing technologies. We appreciate BPA's collaborative approach to facilitating the interconnection of these new technologies, as well as the option for existing non-eligible projects to add energy storage devices ("ESDs") in order to qualify. However, we are concerned that there appears to be little transparency into how BPA would determine whether a given project qualifies for participation in the pilot. We request that BPA share any criteria it has in place for making such a determination or develop and share criteria if it does not already have any in place. Based on the discussion at the July 30 workshop, we understand that BPA proposes to exclude standalone ESDs from this pilot. BPA indicated that it has yet to finalize a recommendation with respect to standalone ESDs. We continue to recommend that it is premature for BPA to implement a new use-based capacity charge for standalone ESDs at this time, but look forward to future discussions on this issue.	commits to operate in such a way to reduce the use of balancing reserves. We have given careful consideration to your comments regarding BPA developing a new use-based capacity charge for ESDs. BPA will address this at the August 27-28 BP/TC-26 workshop.

VI. Comments Received in Response to the August 9, 2024 BP-26 Workshop

Row #	Stakeholder	Comment	BPA Staff Response
93	Seattle City Light	**ESS** City Light supports BPA recovering the full cost of load uncertainty using cost causation principles. City Light suggests that BPA explore ESS charges that fully recover the costs for load uncertainty, including uncertainty for extreme weather conditions.	Thank you for your comment.
94	Seattle City Light	**UAI** City Light supports BPA staff Alternative 3 that reflects hourly market energy cost conditions and monthly capacity demand rate conditions. City Light additionally supports the proposed UAI Waiver Language.	Thank you for your comments. BPA staff plan to propose a slight improvement to Alternative 3 to keep the tie to the monthly demand rate, as supported by Seattle City Light, while also maintaining a balance of the impacts of the monthly Demand UAI when UAI applies in 4 or less hours in a month.
95	Seattle City Light	**Demand Rate** City Light supports the concept that the Demand Rate should be a long run price signal that incentivizes energy and resource decisions. City Light also supports limiting rate shock impacts to customers. In this context, City Light suggests that BPA ramp in a substantial amount of the 23% increase in the Demand Rate yearly over the rate period. This could occur with a 7% increase applied in each of the three years of the rate period.	Thank you for your comments. BPA will address this suggestion in the Demand Rate Wrap Up presentation at the September 25-26 BP-26 workshop. BPA intents to have a robust phase-in of the change. We considered applying a different Demand Rate to different years of the Rate Period, but determined that the added complexity was unnecessary under the circumstances. Relative to our first workshop materials, our proposal moves in the direction of Seattle City Light's proposal while also maintaining the simplicity of a single demand rate for the entire rate period.
96	Northern Wasco County PUD	**ESS/UAI** NWCPUD appreciates BPA's willingness to consider alternatives to current implementation, however, the August 9th proposals fail to address a few fundamental issues: • Some wholesale energy suppliers are no longer responding to Preference Customer 'Requests for Offers' due to BPA's unreasonable UAI penalty structure.	Thank you for your comments. BPA is considering some proposed changes to the UAI based on stakeholder feedback. Staff believe some of these changes will help address some of NWCPUD's concerns. BPA Staff continue to support handling capacity and energy separately as the most equitable and transparent method to address situations where a customer takes more power than they are contractually allowed to take. If energy and capacity are measured and mitigated distinctly, BPA avoids any inadvertent double counting. We disagree that the

Row #	Stakeholder	Comment	BPA Staff Response
		• Wholesale energy suppliers, willing to accept UAI risk in their offers, are applying significant risk premiums to manage their overall risk exposure, thus passing along significant costs to retail customers. • Because UAI energy settles at market prices (ICE Mid-C Daily Index), the price already contains a significant contribution to fixed capacity costs when capacity is constrained in the Mid-C market. This effectively results in double-counting resource capacity costs. When taken together, BPA has clearly created an unfair competitive advantage for itself in the wholesale power marketplace that is detrimental to its Preference Customers. NWCPUD does not believe this is BPA's intent but is the basis for our insistence that BPA's ESS and UAI Charge implementation must be reformed.	energy imbalance market is designed to recover capacity costs. Please see the next question for our response on ESS-related concerns.
97	Northern Wasco County PUD	**ESS** In BPA's August 9th NR ESS proposal (at slide 23), staff proposes to increase the economic penalties for even minor schedule versus load differences. BPA staff has based its proposal on data that purportedly shows large differentials (over 200 MW) between NLSL loads and resources (at page 22). NWCPUD is fully aware of our contribution to this load and resource differential and offers a suggestion that BPA should conduct customer outreach prior to developing any proposal. Customers may provide new insights into this issue, which will help inform BPA staff and potentially yield better outcomes. NWCPUD typically manages our load and resource position in a very tight band (< 5 MWs) during on-peak hours with an overall monthly net energy well within BPA Rate Treatment B threshold of 1,488 MWh <u>surplus delivered to BPA during the On-Peak periods</u>. NWCPUD recommends that BPA maintain the current NR ESS implementation for BP-26; however, if BPA is determined to make a change, then NWCPUD offers the following proposal for consideration:	BPA staff will address this issue more completely in the ESS portion of the September 25-26 BP-26 workshop. Staff are incorporating many of the ideas that ESS customers would like to see implemented in BP-26. Today, the current implementation of ESS does not perform as originally intended, and BPA staff believe it is essential to create a more robust ESS product that addresses many of the shared concerns that customers and BPA have with the current ESS.

Row #	Stakeholder	Comment	BPA Staff Response
		NWCPUD's NR ESS Energy Rate Treatment B with modifications: In the spirit of compromise, NWCPUD offers that for BP-26 the monthly sum of such daily/diurnal energy charges may be adjusted as follows: • Threshold 1: No adjustment is made if the absolute value of the monthly sum of the daily HLH plus LLH Billing Determinants is less than or equal to (1) 1.5 percent of the total monthly measured load of the NLSLs receiving this service, or (2) 1,488 MWh. • Threshold 2: If Threshold 1 is exceeded, Threshold 2 will apply if the absolute value of the monthly sum of the daily HLH plus LLH Billing Determinants is less than or equal to (1) 7.5 percent of the total monthly measured load of the NLSLs receiving this service, or (2) 3,720 MWh. If Threshold 2 applies, the monthly sum of the daily/diurnal energy charges will be multiplied by 94 percent if the monthly sum is negative (money owed to the customer) or multiplied by 106 percent if the monthly sum is positive (money owed to BPA). • Threshold 3: If both Threshold 1 and 2 are exceeded, Threshold 3 applies. When applying Threshold 3, the monthly sum of the daily HLH plus LLH energy charges is multiplied by 50 percent if the monthly sum is negative (money owed to the customer), or multiplied by 116 percent if the monthly sum is positive (money owed to BPA). NR Rate Customers should be offered a BPA capacity product that increases the deadband for Threshold 1 treatment.	
98	Northern Wasco County PUD	**UAI** At slide 41, BPA implies that a UAI settlement based on the existing rate schedule will not cover the cost of energy supplied by BPA to a customer receiving energy in excess of its contractual amounts. Because BPA bills customers at a multiple of the EIM price for Unauthorized Increases, this also	The UAI Charge is designed to deter customers from taking energy and capacity in excess of their contractual rights. If not properly set, BPA may face power demands far above its contractual obligations and its planned system capability, which could result in a significant erosion of BPA's financial position and inability to recover its costs and meet the US Treasury repayment schedules.

Row #	Stakeholder	Comment	BPA Staff Response
		implies that BPA cannot purchase energy at the EIM price and receive a substantial margin on the sale and delivery to the customer at the UAI price – which may also include a UAI demand charge. Lack of confidence in the Western Energy Imbalance Market, demonstrated by this BPA assertion, undermines the confidence of customers that BPA is ready to participate in organized markets that are designed specifically for the purpose of providing and settling energy imbalances that are typical for instances of UAI charges. EIM market prices reflect the cost of capacity committed to provide energy to load in the Western region whether it be from BPA or other power producers. During periods of capacity and energy scarcity, EIM prices far exceed the embedded cost of either capacity or energy – they are market-based prices, not regulated rates. The "Analogy" offered on page 46, is a non-sequitur in a market-based pricing environment. The market price will reflect whether capacity is available in the system for the next increment of demand – just as hotel rates and airfares increase as demand increases. For purposes of BP-26, NWCPUD recommends maintaining BP-24 implementation for purposes of assessing penalties; and, BPA should implement waiver conditions as described on slide 54.	As for BP-26, BPA staff plan to propose an improvement to Alternative #3 to balance it with feedback received and some of the other alternatives that BPA staff presented. BPA staff do plan to implement the UAI waiver language in the Power GRSPs.
99	NRU	**Demand Rate** NRU appreciates BPA's analysis on how current inflation and interest rates will impact the BP-26 demand rate; we agree that the demand rate was intended to be a long-run price signal that should not be overly impacted by volatile inputs. NRU supports BPA's proposal to use the TRM dampening methodology to limit the increase to the BP-26 demand rate.	Thank you for your comment. BPA will address this topic in the Demand Rate Wrap Up presentation at the September 25-26 BP-26 workshop.

Row #	Stakeholder	Comment	BPA Staff Response
100	NRU	**Tier 2 Rates** BP-26 is the last rate period under the TRM and will likely be the rate period with the highest Tier 2 rates and largest amount of power priced at Tier 2 rates. Over the years, BPA has used a variety of marginal price forecasts and indexes to value the energy sold at Tier 2 rates. NRU asks BPA to consider using one of the historically utilized marginal price forecasts, specifically firm (P10) Aurora prices, to value any Firm Surplus used to serve power sold at Tier 2 rates. It is important to note that the intent of this request is to temper the very high rate impacts some NRU members will see due to high Tier 2 rates, while still using marginal prices to set Tier 2 rates in accordance with the principles of the TRM. If the amount of Firm Surplus available in BP-26 makes the impact of this proposal on Tier 1 rates too big, then we ask that BPA consider valuing Firm Surplus used to serve power sold at Tier 2 rates in BP-26 similar to the manner in which it set Tier 2 rates in BP-24. Both proposals described above are specific to how to value Firm Surplus used to meet BPA's Tier 2 obligations. If BPA makes an actual forward purchase to support its Tier 2 obligations, then those costs should be collected in the appropriate Tier 2 cost pools.	BPA staff acknowledge that this rate period will see higher loads served at Tier 2 rates, high forecast market prices, and uncertain market conditions. Staff also acknowledge that marginal prices for Tier 2 must be used that do not undermine the cost-shift principle in TRM. Given the Tier 2 and market conditions present for BP-26, BPA staff has considered a new approach to Tier 2 pricing that we believe will provide customers additional choice to help manage these conditions while still maintaining the cost tenets of the TRM. This new pricing approach is described in the September 25-26th BP-26 workshop materials.
101	NRU	**UAI** NRU appreciates the presentation on UAIs and the alternatives shared during the workshop. We support Alternative 4, setting the energy component at two times the cost of energy during the hour in which the penalty occurred and moving to a daily demand penalty. We also support adding UAI waiver language to the Power GRSPs.	BPA staff plan to propose an improvement to Alternative #3 to balance it with feedback received and some of the other alternatives that BPA staff presented. BPA staff do plan to implement the UAI waiver language in the Power GRSPs. BPA staff continue to believe Alternative #4 is also a reasonable option, but think an altered Alternative #3 may ultimately perform better when it's needed most, better support equity, and align with the rate treatment used in most other areas of BPA's rate design, where a monthly capacity billing determinant is used and not where a daily capacity billing determinant is used.

Row #	Stakeholder	Comment	BPA Staff Response
102	Central Lincoln PUD and Mason PUD	**Tier 2 Rates** Central Lincoln and Mason 3 support BPA staff's proposal as found on slide 34 of the presentation. One of the core principles of the Tiered Rate Methodology is to ensure Tier 1 rates do not include the costs to serve above-right period high water mark load to the extent possible. The BP-24 Settlement allowed some costs to shift from the Tier 2 Rate into Tier 1 to mitigate the effects of rising market prices. While this may have been acceptable due to the Tier 1 Rate not increasing over BP-22, BPA has indicated a potential large increase in the Tier 1 Rate for BP-26. With that said, Central Lincoln and Mason 3 support the stated proposal but would be concerned if it were to evolve into one that produced even a higher subsidy then this would already provide.	Thank you for your comments. We agree that the use of marginal prices for Tier 2 rates should not undermine the cost-shift principle in TRM. Aurora is a time-tested and widely adopted method for forecasting marginal market prices. Aurora is used in many places to forecast marginal energy rates, including the Secondary Net Revenue credit, and thus we would not characterize the use of it to set Tier 2 rates as a subsidy. Rather, we must consider how that index may be used to best approximate the cost of serving power at Tier 2 rates relative to the likely terms (spot vs. forward) during which that obligation is fulfilled. Please also see the September 25-26 BP-26 workshop materials on Tier 2 rates for further thoughts on how BPA staff propose to set Tier 2 rates for the BP-26 rate period.
103	NLSL Group	**Relationship of Over-/Under-Scheduling Generation to Load Forecast Uncertainty** The NLSL Group believes that there should be very little load uncertainty associated with over-/under-scheduling generation to NLSL load since: • NLSL loads can be generally characterized as flat and exhibit less weather-dependent variability than other load types, and, as a result, NLSL loads can be forecasted in the operational horizon with a high degree of accuracy. In fact, organized markets treat load like NLSL load as "non-conforming" load which is treated and forecasted differently than weather-dependent load forecasts. • Scheduled deliveries of generation to meet NLSL load are established in the preschedule horizon and may receive minor adjustments from day-to-day. • BPA receives after-the-fact metered load and schedule information for each NLSL. Given these facts, the NLSL Group believes that BPA should be able to develop tools to easily and accurately forecast over-/under-scheduling of energy over	Please see the September 25-26 BP-26 workshop material on NR ESS. BPA staff's proposal incorporates many of the features the NLSL Group proposed, and Staff believe it should go a long way in addressing the concerns the NLSL Group raised that are ripe for the BP-26 rate period.

Row #	Stakeholder	Comment	BPA Staff Response
		any near-term time horizon. The NLSL Group is open to discussing with BPA ways to improving the exchange of load and schedule information, where appropriate to improve these forecasts. Furthermore, the NLSL Group believes that operational tools and processes (such as treating NLSL load as nonconforming load) is a much better approach than tweaking rate products to solve load uncertainty issues.	
104	NLSL Group	**NR ESS Energy** The NLSL Group does not support BPA's proposal to increase salvage value penalties. As mentioned above, the NLSL Group does not believe that tweaking NR ESS is the best approach for dealing with load forecasting issues. Furthermore, BPA offered no estimate on how the new penalty structure would increase scheduling accuracy or proposed a measure for how much error is acceptable. Unless BPA can demonstrate the value of these penalties, the NLSL Group believes this penalty structure should be completely removed from ESS. For Rate Treatment B, the current method for settling NR ESS Energy charges relies on ICE Midday ahead HLH/LLH power price indices and is unnecessarily complex. The NLSL Group believes that there are more appropriate metrics (such as hourly WEIM prices) that better reflect cost causation and encourages BPA to have a conversation about alternatives that will simply the ESS Energy charge calculation and better reflect cost causation.	Please see the September 25-26 BP-26 workshop material on NR ESS. BPA Staff's proposal incorporates many of the features the NLSL Group proposed, and staff believe it should go a long way in addressing the concerns the NLSL Group raised that are ripe for the BP-26 rate period.
105	NLSL Group	**NR ESS Capacity** BPA states in the slide deck that Customers over-/under-schedule generation to load, in part, to avoid paying for ESS capacity. However, the NLSL Group's hesitancy to purchase ESS Capacity is, in large part, driven by a lack of understanding in how BPA will implement this product.	Please see the September 25-26 BP-26 workshop material on NR ESS. BPA Staff's proposal incorporates many of the features the NLSL Group proposed, and staff believe it should go a long way in addressing the concerns the NLSL Group raised that are ripe for the BP-26 rate period. Staff will address these questions specifically.

Row #	Stakeholder	Comment	BPA Staff Response
		Some questions that NLSL Group members have include: • Will NR ESS Capacity be treated as qualified capacity for the purposes of NLSL WRAP participation? • Will NR ESS Capacity be held out of BPA's secondary marketing through the operating hour or will it be released prior to the operating hour? • How will BPA ensure that a Customer's purchase of NR ESS Capacity be used when NLSL load exceeds generation? • Does the Federal system have a limit on the amount of NR ESS Capacity that can be supplied? The NLSL Group looks forward to learning more about how NR ESS Capacity will be implemented.	
106	NLSL Group	**UAI** BPA offered several alternatives to UAI charges that were agreed upon in the settlement for BP-24, and the NLSL Group offers these thoughts: • It is not clear what problems these proposed UAI changes are intended to solve and to what extent these changes will remedy the problems. Is there any evidence that BPA has faced or will face "power demands far in excess of its contract obligations and its planned system capability". The total Billed Line Counts included in the slide deck suggest that the total number of UAIs is lower today than in 2012-2016 and relatively stable since 2016. • Over-/Under-scheduling of generation to NLSL load is done exclusively to avoid UAI charges. As a result, additional penalties will likely increase the amount of over-/underscheduling of generation to meet NLSL load. • Some wholesale energy suppliers are no longer responding to solicitations due to BPA's existing UAI penalty structure or are applying significant risk premiums to manage their overall risk exposure. This combination is causing significant concern for	Thank you for your comments. There are limits to the amount of unmet load that markets are designed to provide. Generally, markets like the EIM, are designed to more efficiently dispatch generation ***after*** capacity requirements have been met – including a customer's capacity obligations to BPA as defined in its Power contract. Therefore, BPA staff continue to believe that there should be appropriate rate deterrents in place when customers do not meet their contractual obligations, because not meeting those contractual obligations can have downstream impacts on BPA, other customers, and even beyond BPA. Said differently, markets do not make contractual obligations (both energy and capacity) meaningless. For BP-26, BPA staff plan to propose an improvement to the BP-24 UAI approach and further improvements to Alternative #3 based on customer feedback. Staff believe these improvements should address, at least in part, some of the NLSL Group's concerns with Power's UAI Charge.

Row #	Stakeholder	Comment	BPA Staff Response
		Preference Customers serving NLSLs and raising the question of BPA creating a competitive market advantage. • Should there be a demonstration that BPA is supplying additional power rather than the market (EIM, for example)? If the market is supplying additional power, should UAI even apply? • How do other utilities/PMAs who participate in organized markets treat UAI? • Can BPA demonstrate that UAI has in fact harmed either BPA or other preference customers or incurred a cost that should be recovered? The NLSL Group supports a holistic re-evaluation of UAI charges in the context of implementing best practices used in organized markets in order dis-incent customers from using uncontracted Federal resources to meet load. Until then, the NLS Group prefers to maintain the agreement reached in the BP-24 settlement.	
107	NLSL Group	**Market Enabled NSLS Load Service** The NLSL Group has developed a proposal for Market-Enable NSLS Load Service (included in the appendix to these comments), and there are features in this proposal which can help address issues discussed at this workshop. See comments posted on the BP-26 Rate Case webpage for the complete proposal.	Please see the September 25-26 BP-26 workshop material on NR ESS. BPA staff's proposal incorporates many of the features the NLSL Group proposed, and staff believe it should go a long way in addressing the concerns the NLSL Group raised that are ripe for the BP-26 rate period.

VII. Comments Received in Response to the August 27-28, 2024 BP/TC-26 Workshop [UPDATED]

Row #	Stakeholder	Comment	BPA Staff Response
108	Seattle City Light	**General Comments and Requests** City Light, like BPA is experiencing upward rate pressure for a multitude of reasons. City Light suggests that BPA continue prudent investment in maintaining federal generation, expanding federal transmission system to meet customer needs, and growing personnel resources to better serve customers. These increased investments should be tied with accountability for timely execution and performance. City Light additionally suggests that BPA limit the rate shock of the multiple areas driving higher rates by stepping rate increases in most areas across the rate period in yearly steps. This methodology provides revenue for needed investment and appropriate price signals while limiting single year customer impacts. City Light requests BPA provide additional details regarding the drivers of power and transmission rates at the last scheduled pre proceeding workshop on September 25th. Informed customer engagement regarding balancing rate level with risk mitigation is more robust and less constrained in the informal workshop environment.	Thank you for your comment. BPA is not exploring phased in rates or implementing annual rate changes. BPA is still gathering inputs and completing rate analysis that will be reflected in the Initial Proposal. As such, BPA does not plan to release any preliminary rate projections prior to the Initial Proposal. During the pre-proceeding workshops, BPA has discussed the various components used to calculate transmission rates and the drivers behind their movement.
109	Seattle City Light	**Generation Inputs Capacity Costs** City Light requests BPA provide greater detail regarding increase in financing costs, increase in fish and wildlife costs, and increase in forecast power purchases that are driving the 29% projected increase in the embedded cost of capacity.	Thank you for your comment. The embedded cost of capacity will be updated for the BP-26 Initial Proposal, so the 29% project increase is likely to change. The following illustrates how the individual components of embedded cost of capacity influence the end result. Based on information available to BPA at the time, the primary drivers of the 29% increases included: 287aMW increase in Power Purchase Costs (+$106M), 12% increase in Financing Costs (+$95M), and 17% increase in Obligations, including F&W, (+$51M). These cost increases, in addition to a decrease in the FCRPS 1-hour Peaking Capacity Amount (-771MW), resulted in a 29% projected increase in the embedded cost of capacity.

Row #	Stakeholder	Comment	BPA Staff Response
110	Seattle City Light	**Power and Transmission Risk** City Light supports BPA evaluating and mitigating risk associated with Treasury Payment Policy. This includes changing how much of the Treasury Note Facility is set aside for with-in year liquidity. City Light requests that BPA consider instituting a policy that the value of Planned Net Revenue for Risk (PNRR) must be fully returned to customers if a Rate Distribution Clause is triggered.	Thank you for your comment.
111	Seattle City Light	**BPA Response to 8/15/2024 Customer Presentation** City Light appreciates BPA being responsive to substantive customer requests and recommendations. City Light thanks BPA for the detailed explanation of the "higher-of" two-tiered revenue requirement test.	Thank you for your comment.
112	Seattle City Light	**Increased Transmission Revenue Financing** City Light supports BPA's Sustainable Capital Financing Policy and BPA's plans to adopt revenue financing for the rate period that are greater than the default amount in response to regional transmission expansion needs. City Light additionally supports BPA's proposal to return to a base of approximately 10% revenue financing for Transmission capital needs. City Light requests that BPA take steps to ensure effective and efficient use of these capitol funds. City Light suggests setting a minimum goal of 95% execution on capitol transmission projects should be part of those steps.	Thank you for your comment. Staff agrees that capital execution and efficient use of capital dollars is important. Transmission Services, with its use of the secondary capacity model, has improved its capital execution rate to near 100%. The standard governance practices BPA employs to monitor project scope and budget will continue, and Transmission Services will continue to report out regularly at the Quarterly Business Review Technical Workshop, focusing on these areas.
113	Seattle City Light	**Power Rates – Transfer Service Delivery Charge** City Light asks BPA to reevaluate the estimated TSDC. City Light suggests it is highly unlikely that the related costs inputs will not greatly increase more than 4% in the BP-26 rate period over the current TSDC amount.	Thank you for your comment. BPA will re-evaluate the estimated TSDC charge upon finalizing the charge. Both components of the charge—costs and loads, will be revisited before the Final TSDC rate is established.

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Row #	Stakeholder	Comment	BPA Staff Response
114	Seattle City Light	**ACS Design for Energy Storage Devices** City Light suggest that the volume of Energy Storage Devices placed into service during the BP-26 rate period is high enough that BPA should implement an ACS rate for ESDs in BP-26.	Thank you for your comment. BPA agrees that the growth of Energy Storage Devices will result in BPA needing to establish an ACS rate for ESDs. However, the forecast of Energy Storage Devices for BP-26 rate period currently shows no projects with a high probability of being placed into service. As BPA stated in the August workshop, BPA reserves the right to implement an ACS service and rate for ESDs via a mini-7i process if BPA experience ESDs being placed into service in BP-26.
115	Seattle City Light	**Preliminary Generation Inputs Rates** City Light supports BPA applying cost causation principles regarding regulation and frequency response reserves, operating reserves, DERBS, and VERBS rates. Providing timely price signals to customers regarding the necessary resources to maintain expected reliability levels is transparent and prudent management. City Light requests BPA outline the specific impact on transmission rates from Generation Inputs at the September 25th workshop.	Thank you for your comment. Generation Input rates are entirely self-contained and will not impact other transmission rates. BPA will share several possible Generation Input rate impacts along with the Balancing Reserves Shortfall discussion as part of the September workshop.
116	AWEC	**General Comments and Requests** While we understand that a comprehensive overview of BPA's rate proposal will be presented as part of BPA's rate case filing, the information that has been made available through the IPR and the BP-26 workshop series has made it appear nearly certain that Customers will be presented with a significant rate increase in the BP-26 Rate Adjustment Proceeding. It appears likely that significant increases will be proposed for both the power and transmission business lines. AWEC provided comments specific to the cost increase drivers associated with the IPR. As BPA prepares its initial proposal, it is critical to consider the cumulative effects of increases that are being discussed with customers in individual forums. In an effort to provide constructive and helpful feedback from customers to BPA, AWEC has attempted to consider each of BPA's proposals to increase spend and other rate drivers on its own merit. However, we are increasingly concerned that the cumulative effect of BPA's various proposals will lead to a rate increase in BP-26 that will simply not be tenable for customers.	Thank you for your comment. BPA remains committed to cost management when developing future spending levels.

BP-26 Rate Case & TC-26 Tariff Proceeding Workshops
Summary of Written Comments Received and BPA Staff's Reponses

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Row #	Stakeholder	Comment	BPA Staff Response
117	AWEC	**Customer Proposals (Short Distance Discount and Utility Delivery)** AWEC believes that BPA should continue to follow cost causation principles. BPA responded to two different customer proposals that had been submitted in a customer-led workshop on July 11: the Short-Distance Discount and Utility Delivery Charge. AWEC appreciates that BPA recognizes merit in further examination of the Short-Distance Discount proposal, which, we believe, would both incentivize customer investment in the system and recognize situations in which behind the meter generation reduces the impact of load on the BPA system. While BPA has stated that it is not feasible to take up this proposal in BP-26, we encourage BPA to look carefully at this proposal in a future rate adjustment proceeding. On the other hand, the Northwest Requirements Utilities' proposal to roll in the utility delivery charge into network segment rates has been raised and considered by BPA and stakeholders in the past. This proposal has been opposed by many customers and rejected by BPA in the past on the grounds that it would shift costs that have been incurred to serve individual utilities into network rates, requiring all user of the network segment to subsidize specific utilities that find it hard to bear the costs of facilities created specifically to serve them alone. AWEC is sympathetic to the plight of a small group of customers paying a rate that feels painful and outsized but encourages BPA to look for other options for addressing this pain point that do not involve simply creating a subsidy when it comes back to stakeholders as part of its September meeting.	Thank you for your comments. BPA will continue to consider revisions to the Short Distance Discount in future rate periods. BPA will be presenting more information about the Utility Delivery segment at the September 25-26 BP-26 pre-proceeding workshop.
118	AWEC	**Revenue Financing** AWEC has, in the past, questioned whether the two-tiered revenue requirement methodology is optimal, or necessary. Given that BPA has not been receptive to alternatives, we acknowledge that within this framework, revenue financing does not lead to over-recovery or double recovery of the revenue requirement. Rather, AWEC questions the underlying rationale of using customer dollars to finance the system without commensurate value being returned to the customers for the use of their funds over time – which funds are collected above and beyond the lowest possible rates. We are disappointed that BPA continues to misapprehend the cost of supplying such capital to BPA and regularly refer to these dollars as though there is no cost of money associated with the funds. Customers can assure the agency	Thank you for your comment. Bonneville is not revisiting the goals in the Financial Plan and the Sustainable Capital Financing Policy (SCFP) in BP-26. The SCFP ROD Issue 4.2.2.4 addressed the cost of revenue financing compared to debt financing. While we are proposing to include an amount of revenue financing in the initial proposal in accordance with the SCFP, parties will have the opportunity to submit testimony and evidence regarding the amount,

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<tr><th>Row #</th><th>Stakeholder</th><th>Comment</th><th>BPA Staff Response</th></tr>
<tr><td></td><td></td><td>that there is, and that we believe that the cost of revenue financing is generally much higher than BPA’s cost of federal debt.

In the current environment, we urge the Agency to reconsider the levels of revenue financing that are proposed for the upcoming rate period. In the face of substantially greater IPR costs and uncertain markets both for the purchase of the additional power and capacity BPA is likely to need – let alone the uncertainty and lack of clarity currently surrounding net secondary sales rate relief – we believe that the path toward for potential consensus, or at least acceptance, of BP-26 rates very likely includes relaxation of BPA’s revenue financing and leverage goals during the next rate period, while the impacts of recent inflationary periods and deferred maintenance are front and center in the conversation. Notably, BPA itself cites the critical decisional language:

<blockquote>BPA may propose or adopt an amount of revenue financing for a given rate period that is greater than or less than the default amount, in response to circumstances including, but not limited to: changes in BPA’s capital program, prior or forecast triggering of risk adjustment mechanisms, rate pressure, settlement, likelihood of achieving the debt- to-asset ratio policy goal, or whether an amount of revenue financing greater or less than the default amount occurred in a prior rate period.</blockquote>BPA and its customers must cooperate in the face of changing energy markets, loads, emerging markets, and the aftermath of sustained inflation among other things. The answer to all of the pressures cannot simply be the inclusion of more costs in rates. AWEC encourages the Agency to look carefully at each cost bucket, but most particularly, those, such as revenue financing, that are discretionary in nature.

Regarding BPA’s proposal to increase transmission revenue financing, AWEC strongly urges BPA to reconsider revenue financing that would exceed the 1% rate-impact cap included in the Sustainable Capital Financing Policy. By its very terms, the Sustainable Financing Policy is “intended to provide consistent, long-term guidance for BPA’s use of debt and revenues to finance its capital investments.”2 AWEC is concerned that two years after its inception, BPA</td><td>and the Administrator will decide the issue based on the evidence in the record as a whole.</td></tr>
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Row #	Stakeholder	Comment	BPA Staff Response
		may be losing sight of the long-term nature of the Sustainable Financing Policy if its final proposal is to increase transmission revenue financing at an amount that would result in greater than a 1% rate impact to customers. As described more generally above, AWEC struggles to see how any potential customer benefits would outweigh adding an additional 3.4% (or greater) amount of rate pressure.	
119	AWEC	**DERBS** BPA indicates that the Inc rate for Dispatchable Energy Resource Balancing Services ("DERBS") will increase by 248.8%, to approximately $74.30. DERBS is a relatively small portion of BPA's transmission revenue requirement and has generally been justified as a mechanism to incentivize good scheduling practices. Naturally, an increase of this magnitude is difficult for the small group of customers who pay this rate to bear. We understand from discussions during the workshop that significant increases in the cost of the resources that supply the approximately 13 MW of capacity needed for DERBS, exacerbated by the roll-off of the BP-22 DERBS settlement, is driving this potential increase.	Thank you for the comment. BPA understands that forecasted increase in the DERBS rates is impactful.
120	Cordelio Power	**GI Withdrawal Penalties** **Calculation of the Penalty Amount** Cordelio supports Alternative 3, as laid out in slide 145 of the August 27/28 BP/TC-26 workshop. Cordelio believes beginning penalties after Phase One Study has commenced, but before any Phase One Re-studies have commenced will encourage developers to submit projects that have achieved an appropriate level of development. **Exemptions to the Penalty.** Cordelio supports the following exemptions: • The withdrawal does not have a material impact on the cost or timing of any Interconnection Requests in the same Cluster. • The most recent Cluster Study or Cluster Re-Study Report identifies Network Upgrade costs assigned to the Interconnection Request that have increased by more than 25%	Thank you for your comment. As a reminder, BPA is in active settlement discussions for the TC-26 tariff proceeding. During active settlement discussions BPA staff will not be responding to any comments within scope of the discussions, which includes GI Withdrawal Penalties. If a settlement is not reached, BPA will provide a response at a future TC-26 workshop in advance of the proceeding.

Row #	Stakeholder	Comment	BPA Staff Response
		compared to costs identified in the preceding Cluster Study Report or Cluster Re-Study Report. • The Interconnection Facilities Study Report identifies Network Upgrade costs assigned to the Interconnection Request that have increased by more than 100% compared to costs identified in the preceding Cluster Study Report or Cluster Re-Study Report. Cordelio believes this approach will protect developers from the harm created by dropouts while protecting Interconnection Customers from steep withdrawal penalties in circumstances where costs have increased significantly. **Funds Collected Through Withdrawal Penalties** Cordelio also encourages BPA to use withdrawal penalties to help Interconnection Customers who have been harmed by withdrawals.	
121	NRU	**Revenue Financing** At the workshop, BPA staff shared several alternatives for determining the amount of revenue financing in BP-26 transmission rates. NRU supports using the 1% limiter alternative to establish BP-26 revenue financing amounts. It is NRU staff's understanding that this alternative would reduce the annual average amount of revenue financing included in the draft revenue requirement BPA shared on slide 75 of the workshop presentation by $55 million. Like BPA, expanding and enhancing the Transmission grid is a priority for NRU members. NRU supports the proposed capital spending levels BPA forecasts are necessary to meet the evolving needs and load growth of its customers. Due to this time of high forecasted growth and increased budget amounts for BPA Transmission Services, NRU supports a moderate revenue financing alternative to temper the likely double-digit BP-26 transmission rate increases. Otherwise, BPA should reduce the Agency Enterprise Services G&A budget amounts attributable to Transmission Services.	Staff's proposal considers the 1% rate limiter in conjunction with other provisions of the policy, including the clause about proposing an amount of Revenue Financing greater than or less than the default amount, in response to circumstances. As discussed at the workshop, Staff views its alternative as modest given the changes in BPA's capital program and likelihood of achieving the debt-to-asset ratio policy goal. As for G&A allocations, agency services costs are direct charged to the degree possible. The allocation of costs not directly charged is based on estimations of the direction of effort for the various programs.

Row #	Stakeholder	Comment	BPA Staff Response
122	NRU	**Recognition of Alex Lennox** We want to thank Alex Lennox for his many years of federal service and support of Public Power. Alex has been the Power and Transmission revenue requirement study manager since he began at BPA 20 years ago. He has brought considerable expertise and humor to the rate case proceedings, and he will be missed. Thank you, Alex, and congratulations on your retirement!	Thank you for your comment. We agree wholeheartedly and will miss having Alex on the rate case team. But, he isn't retiring until after the BP-26 rate case.
123	Savion	**GI Withdrawal Penalties** Savion reiterates that Bonneville should generally align its Generator Interconnection ("GI") policies with the Federal Energy Regulatory Commission ("FERC") but provides the following observations and recommendations when considering GI withdrawal penalties. 1. Bonneville Should Require Security Sufficient to Cover Withdrawal Penalties Rather Than Rely Upon its Authority to Collect Debts At the August Workshops, Bonneville explained that it does not intend to require security deposits sufficient to cover potential withdrawal penalties assessed because the TC-25 did not include any such requirement and the agency had sufficient authority to bill and collect after an interconnection customer withdraws from the queue, if necessary.2 However, Bonneville noted the agency retained the right to reconsider this decision in a future tariff proceeding. Savion believes that the provision of security to cover withdrawal penalties is squarely within the issue of implementing withdrawal penalties, which Bonneville itself deferred until the current proceeding. It is axiomatic that withdrawal penalties are more meaningful, and will therefore provide a better incentive, if they are fully funded as opposed to relying upon the threat of a potential debt collection process perhaps ten or more years in the future (when Bonneville proposes to provide refunds).	Thank you for your comment. As a reminder, BPA is in active settlement discussions for the TC-26 tariff proceeding. During active settlement discussions BPA staff will not be responding to any comments within scope of the discussions, which includes GI Withdrawal Penalties. If a settlement is not reached, BPA will provide a response at a future TC-26 workshop in advance of the proceeding.

Row #	Stakeholder	Comment	BPA Staff Response
124	Savion	**GI Withdrawal Penalties** 2. Bonneville Should Work With TC-26 Parties to Identify Efficiencies That Might Improve the TC-25 Cluster Study Process Timelines At the August Workshops, Bonneville provided a timeline of the cluster study process that illustrates how much longer the agency's process is as compared to other transmission providers that have implemented FERC's cluster study process. By way of reminder, FERC's process is intended to be run annually whereas Bonneville's process is estimated to take at minimum three years. In response to questions about potentially streamlining the overall process timeline, Bonneville staff explained that it was not able to consider changes that might be inconsistent with the TC-25 settlement agreement. Bonneville's position that it must uphold the TC-25 settlement should not foreclose the opportunity for parties to discuss potentially agreeable improvements in TC-26. For example, Savion observes an overabundance of time has been built into the Customer Review Periods (90 days) and Processing Time (~120 days) in both the Phase 1 and Phase 2 Cluster Studies. In Savion's experience working with Regional Transmission Organizations ("RTOs"), 15 Business Days is sufficient timing to make a decision to proceed. Likewise, subsequent clusters typically begin within 30 days of the end of the customer's review period. Acknowledging that the overall duration of the cluster process was not revealed until the very last moments of the TC-25 settlement, Savion wonders whether customers might prefer to make adjustments in TC-26 rather than wait for a subsequent TC proceeding, consistent with Bonneville's position on security.	See response to row #123.
125	Savion	**GI Withdrawal Penalties** 3. Bonneville's Withdrawal Penalty Proposal is a Vast Improvement Over Doing Nothing At the workshop, Bonneville discussed three alternatives for withdrawal penalties: 1) maintaining the status quo and not implementing any withdrawal penalties; 2) implementing penalties Bonneville describes as similar to FERC's Order No. 2023 rules; and 3) implementing penalties that are assessed earlier and more often than FERC's rules.	See response to row #123.

Row #	Stakeholder	Comment	BPA Staff Response
		Savion appreciates Bonneville's consideration of its earlier comments stressing the need for withdrawal penalties and advocating for consistency with FERC Order No. 2023, and thus, supports Alternative 2.	
126	Savion	**GI Withdrawal Penalties** 4. Bonneville Should Permit a "Penalty Free" Withdrawal Where Estimated Costs Increase from the Initial Cluster Study Report Rather Than the Preceding Cluster Study Report Consistent with FERC rules, Bonneville intends to exempt customers from withdrawal penalties when forecasted Network Upgrades costs increase substantially, but Bonneville's process may need additional considerations. Bonneville proposes to exempt customers that have received either a 25 percent increase in costs as compared to the most recent preceding cluster study report or a 100 percent increase after a Facilities Study Report has been received. Savion's recommendation would mitigate against "cost creep" over the life of a cluster study process. In Savion's experience, costs may increase substantially if there are multiple restudies. In situations where cost estimates increase multiple times, but less than 25% at each step, interconnection customers may ultimately be presented with untenable forecasts but no ability to withdraw. Savion believes this is inconsistent with the spirit and nature of the overall intention for withdrawal penalties, and therefore asks Bonneville to consider whether exemptions should be considered from overall cost increases as opposed to looking at the preceding cost estimates. Cost creep is more significant when considering Bonneville's cluster study process, which may span more than three or four years, because material costs and inflation (even without any changes to engineering and design) may be significant.	See response to row #123.

Row #	Stakeholder	Comment	BPA Staff Response
127	Savion	**GI Withdrawal Penalties** 5. Bonneville Should Use Withdrawal Penalties to Mitigate Harm to Other Interconnection Customers Rather Bonneville's proposal to retain the funds collected from withdrawal penalties is inconsistent with FERC guidance and has not been adequately justified by the agency as appropriate. As explained at the August Workshops, Bonneville does not expect to collect withdrawal penalties and would prefer to use any fees that are collected for operational purposes.6 Savion believes that withdrawal penalties should be used to offset remaining customers' increased costs, not for operational purposes or to generally supplement transmission rates.	See response to row #123.
128	M-S-R	**Power and Transmission Risk** At the August BP-26 workshops BPA indicated that its financial policies regarding capital structure implicitly assume that the associated risks for TBL and PBL are similar. BPA also chose not to include the risk bands associate with the Monte Carlo analysis. In the past these risk bands expressed in dollars of standard deviation have been presented and starkly indicated that the revenue risks associated with PBL were significantly greater than the revenue risks associated with TBL. The primary reason for this difference is: PBL relies heavily on the revenues associated with water year and market prices. TBL relies heavily on revenues from long-term contracts and to a lesser extent short term transmission purchases. The financial results from the last few years dramatically demonstrate this reality. PBL results have swung from positive net revenues of $700 million to a loss of over$ 600 million, a delta of over $1 billion. Given a budget of $2 billion this is quite significant. At this same time TBL net revenues have deviated by less than $30 million, on a budget of approximately $1 billion. BPA's primary policy action is to remove the $75 million of Treasury borrowing authority from the TPP calculation for PBL. M-S-R clearly recognizes that the significant difference in revenue risk between PBL and TBL is not the result of BPA forecasting error or BPA marketing. Rather it is the direct result of the	We recognize that the net revenue uncertainty for Power is greater than that of Transmission, as illustrated by the risk analysis in prior rate periods. As with most prior rate proceedings, risk distributions for the upcoming rate period are not available in time for pre-rate case workshops. We agree that the net revenue uncertainty for Power is significantly greater than that of Transmission, as illustrated by the risk analysis in prior rate periods. The Financial Reserves outcomes in BP-24 Power and Transmission Risk Study, BP-24-FS-BPA-05, Tables 9 and 15 illustrate this difference in risk. Bonneville is not revisiting the Sustainable Capital Financing Policy (SCFP) goals in BP-26. The Policy goals are to establish a capital financing method that (1) moves BPA away from 100% debt financing by revenue financing a portion of capital, and (2) achieves agency and business unit debt-to-asset ratios of no greater than 60% by 2040.

Row #	Stakeholder	Comment	BPA Staff Response
		inability to accurately predict weather and difficulties of accurately forecasting future energy prices. There was discussion regarding revisiting the approach to risk. Any discussions regarding the approach to risk need to recognize the differing risk profiles of the business lines, and provide an opportunity for all customers to participate.	
129	M-S-R	**Power and Transmission Risk – Capital Structure** At the August BP-26 workshops BPA indicated that it applied the same capital structure to both PBL and TBL. (Both are expected to meet an 80/20 structure currently and reach a 60/40 structure by 2040.) Applying the same capital structure to two different businesses implies that their respective financial risks are similar. As the above discussion on risk demonstrates the relative financial risks of TBL and PBL are fundamentally different, not as the result of any failure in performance, but as the direct result of their respective businesses and the inherent associated risks. Specifically, PBL has financial risks nearly 10 -15 times those of TBL. Yet, BPA asserts that each business line should have the same capital structure. An historical lookback results in a similar disconnect. Historically, PBL has had a capital structure either above 100% debt or near 100%. TBL has consistently been below 100% often near 80%-85%. In context this means that BPA has accepted a 100% debt business with significant revenue risks. Currently, both PBL and TBL have debt to asset ratios in the 80% range. Yet PBL has approximately 10-15 times the revenue risk. Based on BPA's current and proposed policy for capital structure it does not appear that BPA considers risk as a material component in capital structure.	The comments confuse capital financing structure with debt-to-asset ratio. The Sustainable Capital Financing Policy envisions each business unit have a 90/10 capital financing structure (90% debt financed, 10% revenue financed). If a business unit is not on track to achieving a 60% debt-to-asset ratio by 2040, it would transition to an 80/20 capital financing structure. Bonneville has not proposed a 60/40 capital financing structure. A 60% debt-to-asset ratio does not mean that a business unit is operating at a 60/40 capital financing structure. The ratio considers the depreciation of assets as well as the pace of debt repayment, which are not factors in describing a capital structure. Further, the debt to asset ratio is one measure of a business' financial health. A high ratio indicates a company might be funding too much of its operations with debt, reducing its financial flexibility, and increasing the risk that future rate payers will bear more risk. The major Transmission capital expansion is primarily driven by customer demand. As a result of the capital expansion, Transmission fixed debt service costs will grow considerably. It is reasonable to place some of this capital expansion risk on current rate payers. The proposal tries to balance this risk tradeoff, by seeking to bring revenue financing in the next rate period to 10% of forecast capital, the floor of what was envisioned in the SCFP. That means that 90% will still be debt financed.

Row #	Stakeholder	Comment	BPA Staff Response
130	M-S-R	**Revenue Requirement** The above analysis clearly documents that BPA does not include relative risk assessment in its determination of revenue requirements. If BPA did, it would target a much higher debt structure for TBL than it does for PBL. (Historically TBL carried a much lower debt-to-asset ratio than the PBL, but that is not necessary for risk.) M-S-R is not suggesting that BPA lower the target for PBL rather M-S-R is suggesting that BPA recognize the very low revenue risk associated with TBL and adjust the target ratio accordingly. A target of 90%/10% is likely quite appropriate for TBL given its very low revenue risk profile. M-S-R recognizes that BPA's Financial Policy is not the focus of BP-26. However, revenue requirements are at issue, and a proposed $375 million of revenue financing to meet a capital structure that is inconsistent with the associated risks is a valid subject for comment. As M-S-R has indicated TBL is not a risky business. A 60%/40% target for a very low risk business is unnecessary and if enforced will result in a significant and unnecessary tax on the region. BPA has consistently highlighted the reality that it provides 75%-80% of the region's high voltage transmission. It also has indicated that the region is approaching full utilization of the available capacity. There is very little risk that BPA will be unable to collect the required revenues to meet its financial obligations. $375 million of revenue financing is not necessary for financial risk purposes. It is not necessary for appropriate capital structure purposes. It does not support economic growth. When in the past BPA faced the prospect of limited access to capital, revenue financing was a last resort option. Today BPA has access to over $10 billion of borrowing authority. It is not capital constrained. BPA does not need to tax the region $375 million. BPA should not tax the region $375 million.	Please see response #129 above regarding risk. As noted in the workshop, the amount of Transmission revenue financing staff discussed represents slightly less than 10% of the BP-26 Transmission capital spending forecast of Bonneville-funded capital investments. Revenue financing recovers the cost of financing a portion of capital investments with cash rather than issuing debt; it is not a tax.

Row #	Stakeholder	Comment	BPA Staff Response
131	M-S-R	**Reserves Distribution Clause Implementation** M-S-R recognizes that RDC distributions are not directly a subject of BP-26. But revenue requirements and the associated rates are at issue and given the magnitude of the proposed revenue increase the potential for net revenues seems quite high. Historically, BPA has distributed much of the RDC for PBL in the form of rate reductions and distributed most of the RDC for TBL in the form of debt repayment acceleration. If it is BPA's intent to continue this policy tendency toward TBL then M-S-R respectfully requests that BPA reconsider its revenue requirements and give further consideration to reductions which may limit the likelihood of a large RDC in the near term. Alternatively BPA should commit to return either business lines excess reserves as rate relief.	Thank you for your comment.
132	M-S-R	**Capital Forecasts and Insufficient Information** In its IPR comments, M-S-R raised concerns about the extreme magnitude of forecasted increases in capital spending, as well as with the forecasted 20% increase to IPR expenses. The concerns are based on historical underspending, and also based on the shear magnitude of the forecasted increase. The forecast calls for over one billion dollars in capital spending for Transmission each year of the three year rate period. The total of $3.7 billion in direct capital expenditures over three years ($4.3 billion with indirects) is more than the $3.6 billion the TBL has actually spent on capital over the past 8 years combined. While increased spending plans are rational given the regions needs, an increase of the magnitude proposed is very likely to be missed. As M-S-R and others commented, there are many barriers that are likely to prevent BPA from ramping up its spending as quicky as forecasted. When customers questioned the level of spending and the lack of information regarding the projects on which the spending would occur, the BPA workshop panel suggested the information should have been provided in the IPR process. It was not provided. It has been a few years since BPA's IPR included project by project projections that created true transparency for customers. In contrast, all that was included in the 2024 IPR was a single line item in the Appendix to the Initial Publication for Expand/Sustain, with nearly $3 billion forecasted over the three years. That level of information is far from transparent. In its IPR	Thank you for your comment. This is better addressed through the IPR process. We acknowledge previous under-execution of forecasted capital spending but reiterate the more recent near-100% level of capital execution. Bonneville's IPR forecast already considers its ability to execute on the expected capital spending. Further, the current revenue financing proposal does not put Transmission on the path to hit 60% by 2040. If under-execution were to occur, Transmission would not overshoot the 60% target.

Row #	Stakeholder	Comment	BPA Staff Response
		comments M-S-R requested a table that summarizes the major expenditures. For example, how much will be spent on new transmission lines? Which lines? How much will be spent on upgrades to existing transmission lines? How much additional capacity will be created? Which specific projects will provide additional capacity, how much, and what revenues are expected to result from the additional capacity? Without additional information there is no way for customers to determine how much is proposed to be spent on new build projects, how much is upgrades and replacements, or how much is associated with the new Vancouver Control Center. The lack of transparency, coupled with the extremely steep slope of the projected increases in spending contributes to customer uncertainty and a lack of confidence in the forecasted spending levels.	
133	M-S-R	**Revenue Financing** The August BP-26 workshops included presentations on potential levels of revenue financing. In particular, slides 52-53 present four potential BP-26 alternatives considered by BPA Staff. M-S-R understands the first alternative "BP-26 w/1% limiter" reflects revenue financing at a level that applies the 1% limiter from the Sustainable Capital Financing Policy. As explained during the August workshops, that alternative would add $15 million per year in revenue financing to the existing $55 million in revenue financing in BP-24, for an annual revenue financing of $70 million, and a total during the BP-26 rate period of $210 million. The other three alternatives would ignore the Policy's limiter and impose even greater revenue financing without regard to rate shock. BPA Staff's alternatives are summarized, below, with a focus on the level of revenue financing each would impose, over and above the other rate pressures for actual costs. [see complete comments on BP-26 webpage] Given the uncertainties surrounding BPA's ability to increase spending to the degree forecasted, and given other IPR rate pressures, M-S-R submits that, at most, BPA should adopt the "BP-26 w/1% Limiter" approach, increasing the annual revenue financing to $70 million per year. Doing so would still tax the region by $210 million over three years, and would cause a 5% increase to rates on top of the likely increase resulting from increased IPR	Consistent with the SCFP, Staff's proposal reflects circumstances for deviating from the default amount of revenue financing. The proposed alternative does not ignore the 1% rate limiter. It considers it in conjunction with other provisions of the policy, including the clause about proposing an amount of Revenue Financing greater than or less than the default amount, in response to circumstances.

Row #	Stakeholder	Comment	BPA Staff Response
		expense forecasts. However, it is the least harmful of the BP-26 alternative presented by BPA Staff. M-S-R reiterates its opposition to revenue financing of forecasted capital expenditures because revenue financing imposes charges on current customers for assets that may not be useful for several years, and which, once they become used and useful, will remain useful for decades to come but will have been paid for in year one. The more rational and prudent approach given BPA's access to debt that does not vary with leverage levels continues to be use of debt with a tenor that resembles the useful life of the assets. M-S-R also agrees with the customer led presentation that explains revenue financing coupled with depreciation results in a duplicative charge to customers. With that said, if the revenue financing under the Sustainable Capital Financing Policy is going to applied, the Policy's 1% limiter needs to be applied as well, particularly given the concerns with the level of forecasted capital spending and resulting rate shock.	
134	M-S-R	**Phased-in Rates** Several customers have suggested mechanisms for phasing in rates, or applying limiters to the rate increases. These approaches were raised during the August BP-26 workshops, as well as in comments to the IPR process. For example, the Public Power Council comments to the IPR suggested a 20% "lapse" factor should continue to be applied to forecasted capital spending, similar to how BPA addressed capital forecasts in BP-22 and BP-24. While PPC's comments focused on the PBL capital forecast, the same should be applied for the TBL. Doing so will help mitigate some of the rate shock that will result from the IPR and capital forecasts presented by BPA Staff. In addition, M-S-R reiterates the approaches it suggested in its IPR comments, a form of contingent IPR budgeting. Similar to the construct of "firm" energy vs. "secondary energy", the construct of "firm" spending" and "secondary spending" could be considered.	Thank you for your comments and creative approach to budgeting. At this time, BPA is not exploring phasing in rates or applying a limit to rate increases. BPA sets rates to recover all costs as required by statute. Changes to BPA's budgeting practices would be best incorporated in the IPR process.

		The IPR could include both "firm expenditures" where the likelihood of execution during the rate period is very high, similar to firm energy where the likelihood of its availability is very high. The IPR also would include "secondary expenditures" where the need is established but the likelihood of execution during the rate period is less certain. In the context of the Initial IPR Proposal for BP-26 this construct might be as follows: (These percentages are for illustrative purposes only. Actual percentages would be developed in the appropriate forum(s)). Firm Expenses. 90% Secondary Expenses 10% Firm Capital 80% Secondary Capital 20% Firm VCC expenditures 95 % Secondary VCC Expenditures 05% Given the historical actual spending of approximately 93% and the magnitude of the proposed escalation in expenditures M-S-R would suggest as an initial allocation the following: Expenses would be partitioned 90% firm. 10% secondary. Capital would be partitioned 80% firm 20% secondary (this recognizes the significant increase and considerable uncertainty). The VCC would be partitioned 95% firm and 5% secondary (this recognizes that this project is in-progress and there should be better information regarding expenditures and availability of labor and materials). In the subsequent 7(i) process rates would be set as firm to recover all "firm" expenditures and as contingent pending the level of actual expenditures during the rate period. If the expenditures reach a defined threshold the secondary rates would be implemented to provide the necessary additional revenues required for completion of the secondary expenditures (programs and work). This approach ensures that BPA has the necessary revenues to perform	

Row #	Stakeholder	Comment	BPA Staff Response
		IPR work but reduces the likelihood that various constraints and uncertainties will result in the collection of excess revenues. Alternatively, BPA should consider moving to a formula rate transmission tariff, which provides transparency on spending levels and creates annual true ups of actual expenses and actual revenues. The result would be certainty on debt repayment probability, and decreased risk to the Agency.	
135	M-S-R	**Generation Inputs Capacity Costs** M-S-R would like to clarify a comment made by BPA at the August BP-26 workshop. It is M-S-R's understanding that BPA assigns capacity value to mid-C purchases. If this is correct can BPA provide more detail.	Thank you for your comment. Power purchase costs are included in the embedded cost of capacity calculation if they are flat annual blocks of power, such as system augmentation, or if they are related to the purchase of the output from a dispatchable resource. These power purchase costs are included because they increase the capacity available to BPA but are not captured by the inclusion of capital-related or fish and wildlife costs. This methodology was described in the BP-22 Joint Power and Transmission Rate Proceeding. Answers to additional questions are available there. Unlike BPA's physical resources – where the capacity-and-energy-cost-classification method can be used to attribute costs to capacity and energy – the cost of power purchases often includes a single $/MWh cost only, with no visibility into the capacity and energy cost components. In these situations, for a given power purchase, a ratio of i) maximum output to ii) maximum output plus average generation is used to separate the total cost into an amount attributable to capacity. For a flat annual block of power, this method attributes 50 percent of the cost to energy and the other 50 percent to capacity.

Row #	Stakeholder	Comment	BPA Staff Response
136	M-S-R	**Revenue Financing** M-S-R's understanding of Revenue Financing is as follows: Approximately 10% of the Transmission rate period's proposed capital budget is financed with revenue from current rates. This means that during the current rate period current rate customers will be paying 10% of the capital cost of investments that may not be energized for several rate periods in the future. Until energized these investments will not earn any offsetting revenues since they will not provide any additional transfer capacity. For the BP-26 rate period BPA Staff suggested that $375 million would be included in rates with no certainty that any additional transfer capacity will be created by the capital expenditures during the BP-26 rate period. M-S-R respectfully requests BPA's response as to whether or not this is a correct understanding.	Staff proposed to use revenues from rates to finance approximately 10% of the annual capital spending by Transmission. Bonneville finances its capital program on a portfolio basis; revenue financing is not tied to specific assets. The capital forecast does reflect both sustain and expand projects.
137	M-S-R	**EIM and Day-Ahead Markets (DAM)** M-S-R understands that BPA has concluded that it may not have sufficient capacity to meet the reserve capacity requirements associated with the projected increases in renewable energy resources. M-S-R understands also that for BP-26 BPA does not assume participation in a day ahead market. If BPA did participate in a DAM would that change BPA's capacity requirements for the additional renewable energy? If not why not? If yes why? During the August BP-26 workshops BPA discussed the reduced DEC Reserves as a result of EIM. How does BPA determine the benefits of EIM of reserves? How is it quantified?	BPA has not committed to joining a DAM and neither market choice has a clear impact for BPA on the Balancing Reserve capacity requirements at this point in their market design development. Until the day ahead markets have finalized their designs, BPA is unable to predict what, if any, impacts may be seen to Balancing Reserve capacity requirements. BPA has made no changes to the quantities of reserves held due to our participation in the Western EIM. During the August workshop BPA staff discussed the removal of variable costs associated with non-regulation balancing reserves (INCs and DECs) due to BPA's participation in the Western EIM. The cost reduction, or offset, is because the Western EIM makes it possible to market non-regulation balancing reserves and recoup most of those variable costs incurred to hold those reserves. The overall cost impact is significant for the non-regulation DEC because BPA only charges variable costs for DECs. The overall cost impact is less significant to the non-regulation INC because its total unit cost is made up of both embedded and variable costs.

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			More information regarding BPA's decision to provide a reduction in the variable costs associated with holding non-regulation balancing reserves can be found in the BP-24 Power Rates Study in section 9.3.1.3.4.
138	NIPPC and RNW Joint Comments	**General Comments** We repeat our request from prior comments that BPA provide initial projections regarding the proposed transmission rate increase that is expected based on updates from BPA's Integrated Program Review ("IPR") process. We seek to better understand the magnitude of the capital and expense increases announced in the IPR ahead of the formal BP/TC-26 process. We also request additional detail regarding the forecasts BPA uses in proposing rates for BP-26. Specifically, the IPR provided only annual estimates of capital expenditure. The IPR does not break down the specific transmission projects that BPA has forecasted it will complete and energize during the upcoming rate period. Without this information, stakeholders cannot reach their own independent conclusions regarding the likelihood that BPA will be able to deliver on a program of transmission investment that is double and triple its current levels.	Thank you for the comments. BPA is still gathering inputs and completing rate analysis that will be reflected in the Initial Proposal. As such, BPA does not have any preliminary rate projections to share currently.
139	NIPPC and RNW Joint Comments	**Generation Inputs Capacity Costs** We appreciate the explanation and reminder of how BPA calculates its generation inputs capacity costs and rates. Following the presentation, however, we continue to have specific questions, including the following: • How does BPA derive the Mid-C price forecast that BPA incorporates into the Aurora model, which is then used to calculate the variable cost of reserves? Is it possible to compare forecasts of Mid-C prices in earlier rate cases to actual MidC prices? • BPA proposes to replace the GARD model with Riverware. We would appreciate BPA explaining the significant differences between the two models' calculations of energy shift	[UPDATED] Thank you for your comments. Please see the September 25-26 BP-26 workshop material on Aurora and the practice of back casting the model to actual market prices and further explanation of the differences between GARD and Riverware. On the topic of generator imbalance energy revenue, BPA's pre and post EIM generator imbalance energy revenues are difficult to compare for several reasons. 1. EIM products are structured differently from what BPA offered in the past. 2. The EIM market footprint is much larger than the BPA BA.

Row #	Stakeholder	Comment	BPA Staff Response
		costs as reflected on Slide 30 of BPA Staff's presentation. Specifically, why are the energy shift costs in Riverware so much less than the energy shift costs using GARD? • We would like additional detail comparing the revenues BPA received from generator imbalance energy charges after joining the Energy Imbalance Market ("EIM") to the comparable revenues it received before joining the EIM.	3. BPA may be serving imbalance from other BAs and other participants may be serving imbalance within BPA's BA. 4. Depending on system conditions, BPA Power may bid more than the non-regulation reserve quantity into the EIM. Additionally, BPA Power participates in the EIM, by bidding participating resources, within a broader market strategy. This implies that whether it is a net purchaser or net seller within that market needs to be considered within the broader context of market opportunities. BPA Power holds the required reserves within the required incremental periods, but ultimately has the ability to strategically manage its bids in such a way as to utilize the value of energy generated on the federal system. Finally, several contextual factors have changes since 2021 which are important to consider when making a backward-looking crosswalk. These changes would have occurred even if BPA had not joined the EIM. Factors include, among others, the significant change in renewables fleet that exists in the BPA BA, as well as the change in real-time energy prices.
140	NIPPC and RNW Joint Comments	**ROFR Queue Management** NIPPC and RNW support BPA Staff's proposal to conform BPA's tariff to its existing practice of awarding rollover rights to customers who request a term of service of 5 years or longer.	Thank you for your comment.
141	NIPPC and RNW Joint Comments	**Revenue Financing** NIPPC and RNW opposed BPA's target for its debt to asset ratio and a target to revenue finance a portion of BPA's capital investment program that were memorialized in the revised 2022 Sustainable Capital Financing Policy. We reiterate our objection to basing BPA's target ratio on inapt comparables of municipal utilities who share little in common with BPA as a federal transmission provider and power marketer. We do support the discretion	Thank you for comments and suggestions. Bonneville's Sustainable Capital Financing Policy (SCFP) set a policy goal that each business unit achieve a 60% debt to asset ratio by 2040. Bonneville is not revising the goal at this time and reiterates the necessity to maintain financial discipline, as outlined in that policy,

Row #	Stakeholder	Comment	BPA Staff Response
		retained in the Financial Plan for the Administrator to determine whether to use revenue financing on a case-by-case basis. In that context, we object to BPA Staff's proposed implementation of revenue financing in BP-26. We recognize that BPA is entering a phase where it is both replacing aging infrastructure as well as expanding the transmission grid to meet demands for new services; in fact, NIPPC and RNW have been at the forefront in urging BPA to increase its investment in transmission expansion to meet regional clean energy targets. We acknowledge that increased investment in the transmission grid will necessarily put upward pressure on transmission rates. We support well-justified, targeted investment in increasing transmission capacity on BPA's system. We also recognize the strain that significantly expanding the capital investment program will place on BPA in meeting the adopted targets of its Sustainable Capital Financing Policy and its Leverage Policy. As noted above, NIPPC and RNW opposed those policies when they were adopted, partly in anticipation of the additional rate pressure BPA's customers face now, which could be mitigated through the continued historical use of debt rather than revenue (effectively, customer cash). At the time BPA adopted the financial policies, we already knew that the region would need to make significant investments to meet the regional demand for clean energy, and we were concerned that requiring customers to revenue finance 10-20% of the proposed capital investment would put significant additional upward pressure on rates far beyond any justifiable need to shore up BPA's finances. In apparent recognition of that concern, BPA incorporated a phase-in as part of its financial policies that would limit the rate impact of revenue financing to 1%. BPA Staff, however, now proposes to ignore that 1% limit on rate impacts from revenue financing and instead recommends BPA impose revenue financing in the BP-26 rates that would result in an incremental 3.4% upward rate pressure. We also question whether BPA has the capacity to execute a capital program of the magnitude forecasted for the rate period. In the recent past, BPA has consistently fallen behind on executing its forecast capital investment program. While that gap may have closed in recent years, BPA's current forecast is aggressive in that it proposes to double and triple the annual	heading into a period of significantly increased capital investment. While we are proposing to include an amount of revenue financing in the initial proposal in accordance with the SCFP, parties will have the opportunity to submit testimony and evidence regarding the amount, and the Administrator will decide the issue based on the evidence in the record as a whole. The proposed alternative does not ignore the 1% rate limiter. It considers it in conjunction with other provisions of the policy, including the clause about proposing an amount of Revenue Financing greater than or less than the default amount, in response to circumstances. We acknowledge previous under-execution of forecasted capital spending but reiterate the more recent near-100% level of capital execution. Bonneville's IPR forecast already considers its ability to execute on the expected capital spending.

Row #	Stakeholder	Comment	BPA Staff Response
		capital spending program over the next three years. We question whether BPA can deliver on capital projects at such an increased pace. According to the financial policies it has adopted, BPA sets its revenue financing levels based on its forecast capital spending for the rate case. If BPA overestimates its ability to spend capital in the rate period, it effectively overstates the amount of revenue financing it should collect during the rate period. In recognition of this, BPA in the past has applied a "lapse factor" to reduce the forecast capital spending (and the associated revenue financing). While we oppose applying any level of revenue financing to customer rates, it would be particularly egregious for BPA to impose a revenue financing requirement on its transmission customers based on a capital spending forecast it cannot deliver and beyond the 1% limit that BPA itself adopted only two years ago. Accordingly, we ask BPA to provide the list of projects that it intends to energize during the rate period, including the dollar investment and confidence level for each project (i.e., the likelihood that a given project will be successfully completed within the rate period). We were very appreciative of the investor-owned utility presentation on the potential for over-recovery from BPA's revenue financing policy. We are much more persuaded by the investor-owned utility presentation that BPA is unnecessarily accelerating repayment of capital than BPA's explanation for why there is not a problem. In its response to the investor-owned utilities, BPA describes the benefits it perceives from revenue financing. BPA does not, however, explicitly recognize the significant upward rate pressure associated with revenue financing or the available alternatives to revenue financing. This is especially troubling given the significant projected rate increases even without revenue financing.	

Row #	Stakeholder	Comment	BPA Staff Response
142	NIPPC and RNW Joint Comments	**ACS Design for Energy Storage Devices** We agree with BPA's decision to postpone development of a use-based charge for balancing reserves for energy storage devices. Given the significant proposed increases in rates for ancillary services for renewable energy generation (discussed in more detail below), we expect to see an increase in developers seeking to co-locate energy storage devices with renewable generation to qualify for BPA's proposed new technology pilot. We look forward to BPA presenting more details on the new technology pilot to shed light on the criteria to qualify for the pilot and anticipated costs of pilot participation.	Thank you for your comment. BPA has no plans to further present on the New Technology pilot from the ACS rates. The pilot is envisioned for the customer(s) to propose an operating paradigm to BPA on the use of their co-located technologies to reduce their combined impact to the BPA balancing reserves. BPA will evaluate any proposals received and work with the customer(s) to refine and implement their proposal. Customers should work through their BPA Transmission Account Executive to get their proposal(s) evaluated by BPA staff.
143	NIPPC and RNW Joint Comments	**Preliminary Generation Inputs Rates** BPA has indicated that ACS rates for generation are likely to increase dramatically—especially the Dispatchable Energy Resource Balancing Service ("DERBS") Inc and solar Variable Energy Resource Balancing Service ("VERBS") rates. The increase in the solar VERBS rate appears to be driven by a significant increase in the amount of solar generation that BPA forecasts will come online in its balancing area during the rate period. We ask BPA to provide information that compares the BPA forecast for wind and solar generation additions used in prior rate cases to actual energization of new generation. We recognize that the accuracy of past forecasts does not necessarily guarantee a similar accuracy for the current forecast, but we believe it would be useful information in evaluating the likelihood that the projected generation will actually come online. Considering that BPA anticipates it will no longer be able to meet the demand for balancing reserves from the federal system but will have to procure additional capacity to meet the forecast need for balancing reserves, having confidence in BPA's forecast o generation additions for the rate period is particularly important. While more data would be beneficial in analyzing the accuracy of BPA's forecast of wind and solar generation additions, we suspect that the forecast may be too high. Among other factors, the significant proposed increase to the solar VERBS rate is likely to act as a deterrent to those resources coming online in BPA's balancing area or cause those resources to co-locate energy	Thank you for your comment. A comparison between Initial Proposal (IP) MWs for Wind and Solar nameplates to what came online during rate periods 18, 20, and 22 are shown in Appendix A, below. Some of the large gaps in solar represent a handful of projects that did not materialize due to circumstances outside of BPA's control. In recent rate cases, projects have been better at coming online consistent with the timing they indicated when signing their interconnection contracts. Solar is also becoming a more established technology in the BPA BAA. Given state and federal clean energy goals, there will continue to be an increase in solar generation across the region.

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		storage devices with their projects, respectively eliminating or reducing those resources' reliance on BPA balancing reserves.	

144	NIPPC and RNW Joint Comments	**Generator Interconnection Withdrawal Penalties**
		NIPPC and RNW have already submitted several rounds of comments on the proposed withdrawal penalties in the generator interconnection process. We recognize – and appreciate – that BPA Staff appears to have carefully considered our comments and those of other stakeholders in reaching its proposed recommendation on withdrawal penalties. As we shift to considering settlement of withdrawal penalties as part of the TC-26 process, we would like to share our high-level settlement principles:
		• We have always considered meaningful withdrawal penalties to be an integral part of BPA's generation interconnection queue reform process, even as we settled other elements in TC-25;
		    ○ Customers whose decisions create additional costs and delays for other customers should bear those costs directly, not socialize them to customers remaining in the interconnection queue;
		    ○ BPA should use any penalties collected to mitigate the harm that a customer's withdrawal imposes on customers continuing in the interconnection queue;
		• Withdrawal penalties and exemptions must be largely consistent with the Federal Energy Regulatory Commission's pro forma Open Access Transmission Tariff with minimal modifications to conform to the process the region developed in TC-25; and
		• We support reasonable exemptions along the lines outlined by BPA Staff in the presentation.
			Thank you for your comment. As a reminder, BPA is in active settlement discussions for the TC-26 tariff proceeding. During active settlement discussions BPA staff will not be responding to any comments within scope of the discussions, which includes GI Withdrawal Penalties. If a settlement is not reached, BPA will provide a response at a future TC-26 workshop in advance of the proceeding.

145	NewSun Energy and the Pacific Northwest Renewable	**Generator Interconnection Withdrawal Penalties** We oppose adding withdrawal penalties to BPA's existing transmission interconnection process. The proposed penalties are premature, factually unjustified, and likely to be both	Thank you for your comment. As a reminder, BPA is in active settlement discussions for the TC-26 tariff proceeding. During active settlement discussions BPA staff will not be responding to any comments within scope of the discussions, which includes GI

Row #	Stakeholder	Comment	BPA Staff Response
	Interconnection & Transmission Customer Advocates	counterproductive and anticompetitive. If BPA adopts penalties, the proposal must be substantially modified to avoid its most counterproductive and anticompetitive impacts. See comments posted on the BP-26 Rate Case webpage for the complete proposal.	Withdrawal Penalties. If a settlement is not reached, BPA will provide a response at a future TC-26 workshop in advance of the proceeding.

Appendix A

The following is additional information in response to comments on the topic of Preliminary Generation Inputs Rates submitted by NIPPC and RNW following the August 27-28 BP/TC-26 Workshop. See comment on row 143.

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

Initial Proposal Forecast vs What Came Online

	Units	Initial Proposal Average	Online Generation Average
Wind Nameplate			
BP-18	MW	2,468	3,311
BP-20	MW	3,060	2,851
BP-22	MW	3,028	2,839
Solar Nameplate			
BP-18	MW	29.5	5
BP-20	MW	236	57
BP-22	MW	166	128

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