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REBUTTAL TESTIMONY OF

LINDSAY A. BLEIFUSS, GARTH T. BEAVON, PETER B. STIFFLER,

and DANIEL H. FISHER

Witnesses for Bonneville Power Administration

SUBJECT: PRDM Rebuttal **Page**

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SUBJECT: PRDM Rebuttal

Section 1: Introductions and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Lindsay A. Bleifuss, and my qualifications are contained in PRDM-Q-BPA-07.

A. My name is Garth T. Beavon, and my qualifications are contained in PRDM-Q-BPA-01.

A. My name is Peter B. Stiffler, and my qualifications are contained in PRDM-Q-BPA-06.

A. My name is Daniel H. Fisher, and my qualifications are contained in PRDM-Q-BPA-03.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to address issues raised in the parties' direct cases. Our testimony is organized as follows: Section 2 describes the overall response to the proposed 2029 Public Rate Design Methodology (PRDM), PRDM-26-E-BPA-01; Section 3 addresses comments regarding the assignment and allocation of secondary revenues; Section 4 addresses cleanup and clarifying changes; Section 5 addresses a concern about the interplay of the Tier 1 Marginal Energy True-Up (METU) and updates to load forecasts; Section 6 addresses a proposed change to the Tier 1 Long-Term Change Fee; Section 7 addresses proposed changes to the PRDM Chapter 9 change language specific to day-ahead market participation; Section 8 addresses Peak Load Variance Service (PLVS) and related Peak Load Variance

Charge (PLVC) concerns; Section 9 addresses matters specific to the treatment of a Joint Operating Entity (JOE); and finally, Section 10 addresses a proposed change to the PRDM published in the Initial Proposal that will fix an inadvertent mismatch between the allocation of load-shaping costs and load-shaping revenue.

Section 2: Parties Overall Response to PRDM

Q. What was the overall response to BPA's proposal on the PRDM?

A. The overall response of parties was broad support for the PRDM as proposed. *See* Safford and Weber, PRDM-26-E-AW-01, at 2 (Alliance of Western Energy Consumers (AWEC)); Traetow *et al.*, PRDM-26-E-JP01-01 (Joint Party 1 (JP01),[1] at 3-4; Bush *et al.*, PRDM-26-E-JP02-01, at 2 (Joint Party 2 (JP02)).[2] Generally, these direct cases spoke to both the specifics within the Initial Proposal as well as the process by which it was created. Specifics included broad support of the tiered rates construct, the simplification and increased transparency of charges and credits, and alignment with the Provider of Choice policy. On the process side, support was expressed for the carefully crafted balance struck across parties in terms of benefits, costs, tradeoffs and compromises.

[1] JP01 is composed of Clatskanie PUD, Grant PUD, Snohomish PUD, Tacoma Power, the Western Public Agencies Group (WPAG), Public Power Council, and Northwest Requirement Utilities.
[2] JP02 is composed of Eugene Water and Energy Board, Lewis County PUD, and Clark County PUD with support from Idaho Falls Power, and Franklin County PUD.

Q. What specific comments of support did parties make?

A. There were many. The AWEC noted that

> . . . the PRDM retains the successful tiered rate structure set out in the TRM, which has served to preserve the value of the Federal system for all customers, while limiting cost shifts among similarly situated utilities. The PRDM improves upon the TRM in a number of areas, including a cost recovery-neutral shift from the TRM's One Cost Allocators ("TOCA") based system to a simpler approach based on actual use of energy and capacity. Several aspects of PRDM better recognize the value of BPA's system, including both the time-of-use energy charges and demand charges that will send stronger price signals to customers and their end-use consumers. Additionally, eliminating Contract Demand Quantity ("CDQs") in favor of disaggregated rate impact credits is an improvement. In particular, the Rate Impact Credit for Capacity ("RICc") serves to "tier" capacity rates, protecting the value of BPA's low-cost resources in a manner similar to how tiered rates themselves protect the value of energy. AWEC agrees with BPA that the RICc will facilitate much clearer price signals.

Safford and Weber, PRDM-26-E-AW-01, at 2.

Similarly, JP02 states that "[o]verall, we find that the PRDM is a well-constructed document that we believe should provide public power with clear direction on rate design for the Provider of Choice contracts. It represents an improvement over the Tiered Rate Methodology (TRM), which was itself a substantial step forward in BPA rate design." Bush *et al.*, PRDM-26-E-JP02-01, at 2.

Q. Did parties support all aspects of the PRDM?

A. No. JP01 acknowledged the PRDM as a carefully crafted balance of tradeoffs and compromises for which they do not agree with all aspects of the PRDM, "[b]ut overall, we agree that the PRDM is a negotiated package that represents a lot of work and compromises on all sides and, for that reason, BPA should faithfully adhere to the words and original intent of the PRDM Initial Proposal, as amended as proposed in this testimony, in its interpretation and implementation." Traetow *et* *al.*, PRDM-26-E-JP01-01, at 4. AWEC views the PRDM as proposed by BPA as a culmination of a number of compromises made by those stakeholders that engaged in the development process and therefore believes that the "PRDM strikes an appropriate overall balance that will result in fair cost allocations to customers." Safford and Weber, PRDM-26-E-AW-01, at 3. AWEC notes it is not completely supportive of every aspect of the PRDM, but states that the PRDM "represents an improvement on the already successful TRM . . . ." *Id.* at 3-4. The Pacific Northwest Generating Cooperative (PNGC) also takes issue with various aspects of the PRDM related to the treatment of a JOE, with particular focus on the calculation of the Tier 1 Demand Charge and the calculation of the RICj. *See generally* Erin Erben, PRDM-26-E-PN-01.

Q. Please list these specific objections or proposed remediations.

A. JP01 seeks changes to a cost allocation principle in PRDM Chapter 2 to account for actual secondary revenues in conjunction with forecast net secondary, which we will address in Section 3. JP01 also proposes several cleanup and clarification edits to the PRDM, which we address in Section 4. JP01 further raises a concern related to the Marginal Energy True-Up (METU) rate and the timing of load forecasts, which we address in Section 5. JP01 also proposes a change to the Tier 2 Long-Term Change Fee, addressed in Section 6, and requests changes to the conditions for revision with respect to day-ahead market participation in PRDM Chapter 9, which is addressed in Section 7 of this testimony. JP02 raises concern with contract election timing and Peak Load Variance Service pricing in PRDM Chapter 5, which we will address in this testimony's Section 8. PNGC raises concern with demand charges and the RICj in PRDM Chapter 5, which we will address in this testimony's Section 9.

Section 3: PRDM Cost Allocation Principle and Secondary Net Revenue Treatment

Q. What are the Cost Allocation Principles and why are they in the PRDM?

A. A description of the Cost Allocation Principles is provided in the direct testimony of Stiffler *et al.*, PRDM-26-E-BPA-03, § 3.1.2. As we explain there, "these principles are designed to provide assurance to stakeholders and guidance to BPA regarding the implementation of the PRDM when faced with new costs, credits, or other changed situations." *Id.*

Q. Did any party suggest any changes to these principles?

A. Yes. JP01 recommends that BPA add to the cost allocation Principle 8(a) a reference to "actual secondary revenue" and a new Principle 8(c) that dictates what happens when financial reserves are above BPA's thresholds as defined in its Financial Reserves Policy. Traetow *et al.*, PRDM-26-E-JP01-01, at 5. Specifically, JP01 requests the following changes to Principle 8(a) and addition of Principle 8(c) (shown in red):

> [A]ll revenues forecast <u>and realized</u> by BPA from its sale of secondary energy produced by the Federal Base System and other resources acquired by the Administrator will continue to be credited to power rates<u>, including surcharges and credits,</u> pursuant to Northwest Power Act Section 7(g) against costs that are properly allocated to rates for recovery from sales of power for use within the region;
> ~~and;~~

> <u>8(c) for circumstances where the financial reserves of Power Services and BPA as an agency are above their respective upper thresholds as defined in BPA's Financial Reserves Policy, the GRSPs shall include within rate period downward rate adjustments applicable to the Tier 1 PF Public rates that are formulaic, automatic, and flow back to BPA's PF Public Tier 1 rates in the next fiscal year consistent with the PF Public Tier 1 rate's proportional load share of BPA's risk provisions.</u>

Q. Why does JP01 want to make these changes?

A. JP01 argues that the addition of the *actual* secondary revenue in Principle 8(a) ensures that the benefits of the Federal Base System are fully assigned and allocated to public customers that have made long-term commitments to purchase power from BPA at rates that recover BPA's total system costs consistent with Section 7 of the Northwest Power Act. Traetow *et al*., PRDM-26-E-JP01-01, at 5. They note that this approach would "mirror" how all of BPA's planned and actual costs are recovered in rates and risk mechanisms from public power customers. *Id.* They view this principle as ensuring that public customers receive both all secondary revenues of the Federal Base System as well as its costs. *Id.*

Q. What is your response?

A. Before stepping into the argument raised by JP01, we do believe it important to add some rate-setting precision to Principle 8(a) that may be lost when focusing on its implications on a single-rate category, specifically PF Public rates paid by public customers that have made long-term commitments. As drafted in our Initial Proposal, and as proposed to be amended by JP01, the principle is inclusive of all power rates set with the costs and benefits of the Federal Base System, as directed by BPA's statutes. As such, it may include other power rates that are not paid by public customers that have made long-term commitments to purchase power from BPA.

Now moving to the argument made by JP01, we understand the basis for this change and believe that the underlying concern that JP01 is raising should be addressed. However, we do not think addressing it through the PRDM is the proper course of action. In particular, the issue JP01 is raising goes beyond the purpose and scope of the principle and implicates a number of other BPA policies and issues not being decided in this proceeding, such as those related to risk and the management of that risk.

Q. Please explain.

A. Principle 8 has its antecedents in the TRM and, thus, is not a new principle. Its overall purpose, as evident from its language ("will continue to . . ."), was to express a practice that had been a part of BPA ratemaking for many decades—namely, to credit to the Section 7(b) rate the forecast net secondary revenues from surplus sales. It was not a new idea but a recognition of a long-standing ratemaking approach that ensured forecast net secondary revenues were allocated to PF rates. This principle also parrots what BPA's statutes already generally required, as seen by the reference to "pursuant to Northwest Power Act Section 7(g)[.]" The inclusion of "forecast" was also intentional because it ensures that this principle operates in the context of ratemaking, which uses projections and estimates to establish rates.

Q. JP01 references "secondary revenues" and you are using the term "net secondary revenues." Can you explain this apparent distinction?

A. Yes. The term *net* secondary revenues are inclusive of the cost of power purchases and the revenue associated with power sales. The term secondary revenues, without the "net," could be used to mean BPA's sales revenue only without factoring in the cost of power purchases. Given that the two are interrelated, such as a purchase in one time period can result in a sale in a different time period, they most often should be evaluated together. This is particularly true if being used as a proxy for BPA's financial performance.

Q. What do you mean by "proxy" for BPA's financial performance?

A. While net secondary revenues are often a significant contributor to BPA's annual financial performance and resulting impacts to the level of its end-of-year financial reserves levels, BPA's financial performance is a function of all sources of revenue and costs, not just net secondary revenue. While we believe JP01 understands these differences in its proposal, it is important to understand that BPA does not currently separate its net secondary revenue performance from its overall financial performance and thus the combination of JP01's proposal to add "realized" to 8(a) and the addition of 8(c) is at best incomplete and at worst incompatible with the way BPA has set its rates since at least 2002 when it first adopted the framework that continues to be used today. For this reason alone, we believe JP01's proposal should be rejected and reevaluated comprehensively in a different process rather than in the PRDM.

Q. Would JP01's suggested edits change the meaning and scope of Principle 8?

A. Yes. JP01's proposed edits implicate the broader issue of how BPA should manage risk within the rate period. That is, JP01's edits to Principle 8(a), and its addition of 8(c), would expand the principle beyond rate setting and move it into BPA's actual *use* of secondary revenue after rates are set. While that may not seem like a big difference, it is. BPA sets power rates using forecasts of several variables that change, including generation, market prices, and loads. In a perfect world, BPA's forecasts of these rate inputs would perfectly match actual reality, and rates would collect neither more nor less revenue than BPA's actual costs. But BPA's forecasts are not perfect, meaning actual revenues and costs often diverge from projections, thereby creating uncertainty and financial risk. How BPA manages the delta between its forecast and its actual financial performance is a complex issue with many counter-balancing factors. Importantly, we have chosen to not address those factors in the PRDM outside what we have expressed in Chapter 7.

Q. *Could you revise the principle as requested by JP01 without addressing the other issues you mention?*

A. No. When we talk about "within rate period" uncertainty and risk, we generally implicate two issues. JP01 identifies one of those issues: what to do with net secondary revenue that exceeds our rate case forecast. They would like BPA to commit to principles that return that additional revenue to customers through lower rates. The other issue is downside cost and other revenue risk. That is, what to do when costs exceed forecasts or other sources of BPA's revenue are below projections. These matters quickly implicate BPA's financial policies, which go beyond the scope of the PRDM. We really cannot address one without addressing the other.

Q. *Does the PRDM address the risks you mention?*

A. No. In fact, the PRDM expressly preserves this issue to "each 7(i) Process . . . " PRDM, PRDM-26-E-BPA-01, at §§ 7.1, 7.2, 7.3. There were preliminary discussions over the summer of 2024 in PRDM workshops exploring both sides of this question—*i.e.*, balancing BPA's need to manage risk with the equities identified by power customers. Ultimately, however, a consensus on how to do this through the PRDM was not reached.

Q. *Why do you think it reasonable not to address these issues within the PRDM?*

A. We believe that addressing this issue through financial policies, rather than the PRDM, better balances flexibility and predictability. And it is BPA's intent to have that discussion soon. BPA expects to take a comprehensive look at its financial policies and risk mitigation, in collaboration with customers and stakeholders, prior to the BP-29 rate period. In that forum, the issue of risk mitigation and equity for power rate payers can be viewed holistically. Adding language in the PRDM could stifle those conversations and constrain the open and fluid dialogue that needs to occur to achieve a reasonable result. That is why we think JP01's concerns are better addressed in that context than in the PRDM.

Q. *Do you think the equity concerns JP01 raised have merit and should be addressed, albeit in another forum?*

A. Yes. We want to be clear that we see merit in the concerns and questions that JP01 is raising. Even though we do not support modifying the PRDM, our position should be understood as being open to further conversations on this issue with customers. We believe these specific issues are important and agree they need to be addressed in an open, collaborative forum.

Section 4: Cleanup and Clarifying Changes to PRDM

Q. *Did any party propose clarification or cleanup changes to the PRDM?*

A. Yes. JP01 proposed a number of cleanup and clarifying edits to the PRDM. JP01 also identifies three of these edits as more substantive changes and explains in their testimony the basis for these changes. *See* Traetow *et al.,* PRDM-26-E-JP01-01, 6-8; *see also* Attachment A, PRDM-26-E-JP01-01-AT01.

Q. *What is your response to JP01's proposed edits?*

A. Generally, regarding the cleanup and clarification suggestions, we think that JP01 highlights several important corrections and improvements to the PRDM that do not structurally alter the overall design. We plan to adopt most of the cleanup and clarification edits suggested by JP01. Rather than walk through each of those proposed edits, we have attached to this testimony a combination of the edits proposed by JP01 that we agree should be adopted as well as other edits we propose to make as supported by this testimony or as our own proposed general cleanup changes. *See* Attachment 1.

Q. *Are there any JP01 proposed cleanup changes not addressed in other parts of this testimony that you did not accept but warrant a specific callout?*

A. Yes. There were three proposed edits that we did not accept, or only partially accepted, that warrant a specific callout. These three proposed edits are noted below for reference and discussion, and the specific changes are found in Attachment 1.

Item 1: JP01 proposes to specify that a qualifying forced outage of a Non-Federal Resource with Forced Outage Reserve Service (FORS) would not be subject to the Unauthorized Increase Charge (UAI), Section 8.1, lines 18-19. We agree with JP01's intent here and propose to broaden it even further to allow for other services and situations where a Non-Federal Resource could have a forced outage and a UAI not apply. This improvement is in line with the intent of the Initial Proposal as written and further illuminates that intent.

Item 2: JP01 proposes to add a fourth bullet that adds Table 3-1 Tier 1 System Resources to Section 9.1.2, which identifies the core provision of the PRDM that may be revised only to ensure cost recovery or comply with a court ruling. We understand why this change was proposed as the Tier 1 System Resources are the foundation for which the PRDM is built. However, we see this change as raising the bar for removing or adjusting percentages for resources listed in Table 3-1—a bar that we believe is already sufficiently high. We believe JP01's proposed change imposes a one-directional risk to the PRDM that could potentially prevent issues from being remedied even with the broad BPA and customer support of Sections 9.2 and 9.3.

Unlike the TRM, where Tier 1 System Resources could not be expanded, the PRDM allows the Tier 1 System Resources listed in Table 3.1 to grow. This is an appropriate adaptation to reflect the new way in which high water marks are calculated, but it does introduce a new vector for creating an unintended consequence. Specifically, a future unknown condition and resulting decision to add a resource to Table 3.1 could create an unintended consequence for which we believe it smart to allow some flexibility to correct, beyond ensuring cost recovery or to comply with a court ruling, if supported by the ability to revise the PRDM for unintended consequences, Section 9.3. We find this particularly compelling given the height of the bars laid out in Sections 9.2 and 9.3.

Item 3: JP01 proposes clarifying language on how the RICc will be calculated for Block customers. This is a good suggestion, especially since JP01's clarifying recommendation did not align with the way we intended to propose the RICc be calculated for Block customers. Thus, JP01 correctly identified that clarification was needed. However, rather than accept JP01's suggested edits, we propose different clarifying edits and propose to pair those edits with the addition of Appendix F to the PRDM, *see* Attachment 7, that provides an example calculation to ensure the PRDM's intent is clear.

Section 5: Tier 1 Marginal Energy True-Up and Updated Load Forecasts

Q. JP01 identified concern with the METU and the timing of updating load forecasts. Please summarize JP01's comments regarding Tier 1 METU and load forecasting.

A. JP01 notes the timing of load forecasts under PRDM and Provider of Choice contracts will change substantially for planned product customers compared with the TRM and Regional Dialogue (RD) contracts. Traetow *et al.*, PRDM-26-E-JP01-01, at 10. Specifically, under the TRM and RD contracts, customers provided their load forecasts on June 30, three months before their service commenced and rates applied. *Id.* at 11. Under Provider of Choice, that timeline is pulled back to 21 months, with an opportunity to update the load forecast if certain thresholds are met. *Id.* These load forecasts impact the application of METU. As such, JP01 contends that "[t]he new METU under the PRDM for Block and Slice/Block customers should be based on timely updates to load forecasts applicable to any given fiscal year and rate period. Additionally, the PRDM and Provider of Choice contracts should include sufficient mechanisms for customers to submit more accurate load forecast updates when appropriate so that they can better manage their exposure to the financial consequences of the METU." *Id.* at 10.

Q. How do you respond?

A. We agree that this is an important consideration and acknowledge instances where BPA has identified similar situations to those highlighted by JP01 where BPA allows a forecast and the resulting billing determinants to be updated outside the normal cadence to address material changes in load expectations. For example, the current General Rate Schedule Provisions provide exceptions that allow a change in a Load Following customer's TOCA after the RHWM Process. *See* Section II.G TOCA Adjustment in the 2024 Power Rate Schedules and General Rate Schedule Provisions (GRSPs). That said, the PRDM does not define when or how a party's load forecast may be updated, nor do we think it should. Rather, the appropriate and strategically more nimble location for such a provision is in the Provider of Choice contract. Thus, we think that this issue can be better addressed through negotiations and discussions in the Provider of Choice workshop process.

Section 6: Tier 2 Long-Term Change Fee

Q. Please describe JP01's proposed change to the Tier 2 Long-Term Change Fee.

A. JP01 proposes the Tier 2 Long-Term Change Fee billing determinant be changed from the Tier 1 Load to the reduction amount requested by the customer to its Tier 2 Long-Term Alternative election. Traetow *et al.*, PRDM-26-E-JP01-01, at 6. JP01's reasoning is that this change more directly aligns with cost causation principles and that a Tier 2 cost is being appropriately applied to Above-CHWM Load.

Q. What is your response?

A. We disagree. First, the size of the fee (the rate being 0.05 to 0.10 mill/kWh as determined in each 7(i) Process) was developed in light of the billing determinant as proposed (Tier 1 Load). This billing determinant coupled with the rate range we propose results in a cost that is reasonably sized and on par and akin to a fixed fee designed to recover costs associated with a change in a customer's decision that likely has impacts on others, but where the impact is difficult to quantify. A more comprehensive cost-causation study that targeted the intent of the fee would likely be difficult to perform, with the actual cost of conducting the study further causing a disproportional cost (*e.g.*, outweighing its benefit). Further, we believe some compensation from the customer leaving the cost pool to the customers left behind is justified given that the Long-Term Tier 2 Alternative is elected as a shared portfolio approach to managing load growth collectively.

Second, the Tier 2 Long-Term Alternative represents a customer's commitment to a pooled option, which BPA plans to fulfill on behalf of that pool. Quantifying a reduction to that option as proposed by JP01 would be extremely difficult in practice and would likely yield a small and difficult-to-calculate billing determinant given its dependence on long-term preliminary load forecasts.

Specifically, BPA will have to manage the pool based on load forecasts that extend beyond when Above-CHWM amounts have been identified, leaving a customer-impacting factor on the Tier 2 Long-Term Alternative with no identifiable billing determinant as proposed by JP01.

Third, if JP01's proposal resulted in any fee, it would simply make a small fee even smaller and not justify the administrative burden and complexity of implementation. For perspective, at its maximum rate—0.10 mills/kWh—a customer paying an average effective Tier 1 Rate of 35 mills/kWh would experience a 0.3 percent rate impact for two years. Any smaller and the entire purpose of the fee, which we believe important, would be lost. Although not our proposal, nor JP01's, removing the fee altogether would be the more practical alternative to the Initial Proposal.

In summary, the Tier 2 Long-Term Change Fee as proposed by BPA: 1) is appropriately sized as a result of the proposed rate and billing determinant; 2) is representative of other customer-change fees applied by businesses when a customer changes its commitment; 3) appropriately ensures that the customers left in the pool receive some cost exposure mitigation as a result of a change in the original plan, as dictated by another customer; 4) includes a superiorly transparent, dependable, and measurable billing determinant relative to JP01's proposal; and 5) represents an important and meaningful amount to those remaining in the Tier 2 Long-Term Alternative while limiting the Tier 1 rate impact on the leaving customer to a few tenths of one percent for two years only.

Section 7: Day-Ahead Markets and PRDM Revisions

Q. What are JP01's comments on PRDM Section 9.3.2?

A. In the Initial Proposal, we included PRDM revisions "to accommodate BPA's participation in a day-ahead market" within the criteria and conditions for revisions for unintended consequences in Section 9.3.1. JP01 states, "[t]his reference to day-ahead markets was not included in prior drafts of the PRDM and was never discussed in the PRDM workshops prior to this proceeding." Traetow *et al.,* PRDM-26-E-JP01-01, at 7.

Q. Do you agree?

A. No. The issue of processes for PRDM revisions to accommodate day-ahead market participation was discussed in the PRDM workshops prior to this proceeding.

Q. Please explain.

A. Early discussions reviewed the different "buckets" for revisions and dispute resolution under the TRM and considered the possibility of creating a new "bucket" specifically for day-ahead market revisions. Given uncertainty about whether BPA would join, and what PRDM revisions—if any—would be needed, BPA's rough draft proposal was to allow different potential revisions related to day-ahead market participation to fall into the various existing buckets. That is, some revisions might be necessary for cost recovery; others might be to address unintended consequences; others might be an improvement or enhancement.

Customers submitted comments in response to BPA's rough draft and first draft of the PRDM. Relevant here, the Planned Product Group's comments stated:

> The PPG requests language either within section 9 or elsewhere as a standalone section within the PRDM that commits the Agency to conducting a process to amend relevant sections of the PRDM to accommodate BPA's participation in a Day-Ahead or otherwise organized market if and when such participation impacts product

> costs and equity. This commitment should generally comply with the outline of section 9 but be contained as an independent obligation not subject to the customer engagement or approval thresholds.

Planned Product Group, Informal Comments on BPA's Rough Draft of the PRDM, at 4-5 (Aug. 12, 2024); Planned Product Group, Comments on BPA's PRDM Draft 1, at 3 (Sept. 30, 2024).

While we did not accept the Planned Product Group's proposal for day-ahead market revisions to be outside the PRDM's amendment procedures, or for revisions not to be subject to customer engagement or approval thresholds, we did see value in separately addressing potential revisions to enable day-ahead market participation. We could imagine a possibility that there might be a package of related proposed revisions to accommodate day-ahead market participation. In view of this possibility, we thought it would be valuable to avoid esoteric fights over whether individual revisions within such a package constitute an "improvement" or an "unintended consequence," with separate processes applicable prior to inclusion in a 7(i) process. Therefore, we modified our proposal.

We discussed this modification at the October 8, 2024, workshop. *See* Attachment 2. The "Initial Proposal PRDM" column on the "Chapter 9 Revisions to accommodate DA markets" row on page 5 states:

> Revisions to accommodate DA market participation will follow processes for Unintended Consequences that Do Not Affect Others, except for revisions for Cost Recovery or Court Ruling, or Unintended Consequences that Do Affect Others (which will follow their respective processes).

Id. at 5.

Our Initial Proposal sought to reflect that intent.

Q. *What is JP01's proposal?*

A. JP01 states they do not object to including revisions to accommodate day-ahead market participation within the "unintended consequences" provisions of Section 9.3, "but we recommend further clarifying language to make clear that such revisions to the PRDM must be proposed under the procedures and requirements in section 9.3.2 rather than under 9.3.3 before advancing to a 7(i) Process." Traetow *et al.,* PRDM-26-E-JP01-01, at 7. JP01 believes "these changes are appropriate because, at this time, we have no reasonable understanding of the scope and scale of changes to the PRDM that BPA may propose to accommodate its participation in a day-ahead market or what impact such changes might have on the carefully constructed compromise that we are supporting in this testimony. Under such circumstances, providing public customers the opportunity to object to such proposal(s) in accordance with the terms of section 9.3.2 before they are proposed in a 7(i) Process is a modest, reasonable, and fully equitable request." *Id*.

Q. *Do you agree with JP01's proposal?*

A. Not entirely. As stated in the October 8 document and workshop, there needs to be a caveat for revisions for Cost Recovery or Court Ruling, or Unintended Consequences that Do Affect Others (which will follow their respective processes). We propose clarification edits to Section 9.3 to conform with that intent. As a default assumption, we expect PRDM revisions related to day-ahead market participation to fall under Section 9.3.2 (Unintended Consequences that *do not* affect others). However, there is a theoretical possibility that a proposed revision to accommodate day-ahead market participation would also be a proposed revision "to address unintended consequences that affect others or general programs or policies" under Section 9.3.3. We do not have any specific potential revision in mind. However, as described in our initial proposal testimony, the PRDM cannot prevent others from presenting evidence and arguments in a rate case. Fisher and Beavon, PRDM-26-E-BPA-10, at 7.

Q. What clarification edits do you propose to effectuate that result?

A. Here are relevant sections of the PRDM with our proposed redline edits.

9.3 Revisions for Unintended Consequences

9.3.1 Criteria and Conditions for Revisions for Unintended Consequences

With the exception of PRDM changes that are constrained by Section 9.1.2 (Core Provisions) or implementation of the PRDM reserved by Section 9.1.3 (Expressly Not Revisions), BPA may, in accordance with the applicable procedures of this Chapter 9, propose revisions in the PRDM~~: 1)~~ to address or avoid unintended consequences that put at risk the Principles and Goals underlying the PRDM as set forth in Section 1.1 of BPA's Provider of Choice Policy. Proposed revisions ~~or 2~~ to accommodate BPA's participation in a day-ahead market will be considered "revisions for unintended consequences that *do not* affect others or general policies" and follow the processes in Section 9.3.2; *except that* proposed revisions that meet the criteria for "revisions to ensure cost recovery or comply with court ruling" and "revisions for unintended consequences that *do* affect others or general programs or policies" will be subject to Section 9.4 and Section 9.3.3, respectively. ~~However, n~~Nothing in this Section 9.3 constrains BPA's ability to propose revisions in the PRDM to ensure cost recovery or comply with a Court ruling that also accommodate BPA's participation in a day-ahead market; such proposals must comply with the requirements in Section 9.4.1. Nothing in this Section 9.3 constrains BPA's ability to propose revisions in the PRDM for unintended consequences that *do* affect others or general policies that also accommodate BPA's participation in a day-ahead market; such proposals must comply with the requirements in Section 9.3.3.

Section 8: Load Following and Block Peak Load Variance Service (PLVS) Product Design and Rate Treatment

Q. What is PLVS and how does it relate to the PRDM?

A. As we explained in our direct testimony, Reed *et al.*, PRDM-26-E-BPA-05, at 17, PLVS is a capacity-based service that transparently formalizes long-held operational planning actions that ensure capacity is planned for and standing ready when loads exceed expected values. PLVS specifically targets the quantity of capacity to meet planning reserve margins above the expected load (sometimes referred to as average load or 50th percentile load). In the development of the PRDM, this planning reserve margin was discussed colloquially as "P10" (or "10th percentile") coincidental-peak load value on a load probability distribution. The rate charged for providing PLVS is called Peak Load Variance Charge (PLVC).

Q. Did any party raise an issue regarding PLVS and PLVC?

A. Yes. JP02 submitted detailed testimony on the purpose, background, and function of PLVS and PLVC. *See* Bush *et al.,* PRDM-26-E-JP02-01, at 3-15.

Q. What specifically is JP02's concern?

A. JP02 raises two specific concerns with PLVC in relation to PLVS. The first concern is that the PRDM is "not equipped to equitably bridge the gap between the two PLVS products." Bush *et al.*, PRDM-26-E-JP02-01, at 4. The second concern is that uncertainty in the rate design for PLVC for Block Product is asymmetric with the uncertainty poised for Load Following Product. *Id.*

Q. What is your response?

A. We disagree that the PRDM is not equipped to equitably bridge the gap between the two forms of PLVS. The proposed PRDM states that PLVC will be priced "commensurate with the service provided[.]" PRDM, PRDM-26-E-BPA-01, at 49. This language provides a transparent acknowledgement that there will likely be differences inherent to PLVS offered across the products and that BPA, in conjunction with stakeholders, will account for these differences when the rate design and rates are established in a 7(i) Process. BPA and customers have demonstrated, sometimes to a fault, the creativity and flexibility that can be proposed and adopted in rate design to manage even the most intricate of rate design problems. We see no reason why that historically vast flexibility, for which the PRDM allows, would be limited in the case of establishing an equitable and commensurate rate design applicable to PLVS for the Block Product.

With regard to the concern of asymmetrical uncertainty between the Block and Load Following Products, we can understand that point of view, particularly as it relates to areas outside the scope of the PRDM—specifically how PLVS product design does or does not conform to future unknown regional planning standards and requirements. This, however, is not a concern for which we believe the PRDM can, or should, attempt to aid. Provided that the PRDM does not confound the concern further, which we believe it does not, the PRDM is striking the right balance of stating its intent while also maintaining flexibility to adapt to the unknown.

Section 9: JOE-Specific Treatment Under the PRDM

Q. What is a JOE and why does it matter to the PRDM?

A. We explain in our direct testimony, Reed *et al.*, PRDM-26-E-BPA-05, at 13-16, what a JOE is and its statutory underpinnings. We also explain there our proposal in the PRDM to use the JOE's members' individual coincident peak for demand charges rather than the collective, aggregated demand of the JOE. We explain in our direct testimony the policy, economic, and rate-based reasons for that treatment. *Id.* Our direct testimony also explains that we recognize this treatment of the JOE is a change from current practice under the TRM, and therefore, propose a rate credit to partially mitigate the impacts of this change. *Id.* 16, 22-27. That mitigation comes in the form of a rate credit that applies exclusively to the JOE, the Rate Impact Credit for the JOE (RICj). *Id.* at 22-27. Our proposal for the RICj provided an initial mitigation payment of $1 million in FY 2029, tapering down to $0 in 2044. *See* PRDM, PRDM-26-E-BPA-01, at § 4.5, Table 4-1. In total, we proposed to provide $8 million in RICj mitigation payments. *See id.*

Q. *Did any party raise concerns with your proposal?*

A. Yes. The Pacific Northwest Generating Cooperative (PNGC), which is the only operating JOE, filed testimony opposing our proposal. Erben, PRDM-26-E-PN-01, at 1-2. PNGC also offers several alternatives and adjustments to the PRDM that they claim would better mitigate the economic impact of transitioning the JOE from TRM to PRDM. *Id.* at 4-5.

Q. *What specific objections did PNGC raise?*

A. The primary concern PNGC's testimony appears to raise is that charging PNGC based on its individual members' demand violates federal law. In PNGC's view, Section 5(b)(7) of the Northwest Power Act was intended to "aggregate" the JOE's members' loads for billing and rate purposes. Erben, PRDM-26-E-PN-01, at 2. The proposed PRDM disaggregates the JOE's members' loads for demand charges, which PNGC claims "likely violate[s] federal law. . . ." *Id.*

Q. *What is your response?*

A. We are not attorneys, and as such, will not opine on the legal merits of this portion of PNGC's argument. We expect that this issue will be addressed, to the extent raised, in the Draft and Final PRDM Records of Decision. However, there are certain factual assertions PNGC makes in its testimony that we think should be corrected.

Q. *Please explain.*

A. To begin, PNGC claims BPA is currently (under the TRM) treating PNGC as "a single preference customer" because BPA has "recognized" that such treatment is "required by law[.]" Erben, PRDM-26-E-PN-01, at 2. In effect, PNGC is asserting BPA previously agreed to aggregate PNGC's members' loads as a JOE under the TRM because BPA viewed this treatment as required by Section 5(b)(7) of the Northwest Power Act. Building from this premise, PNGC then argues that "[n]othing has changed in the law to warrant different treatment under the new Provider of Choice contract construct." *Id.*

Q. *What is your response?*

A. PNGC is incorrect to suggest that the current practice of aggregating PNGC's load under the TRM came about because BPA viewed this as required by JOE legislation. As we explained in our direct testimony, BPA originally intended to treat the JOE's members as "individual utilities . . . for *all* aspects of the TRM[.]" Reed *et al.*, PRDM-26-E-BPA-05, at 16, *citing* Cherry *et al.*, TRM-12-E-BPA-10, at 3 (July 2008) (emphasis added). The aggregation of PNGC's load for demand was the only exception to this general rule, and came "with other counterbalances . . . which, on the whole, were intended to place the JOE in roughly the same position as other customers." Reed *et al.*, PRDM-26-E-BPA-05, at 16. In the end, aggregating PNGC's demand in the TRM was achieved as a result of compromise and negotiation—not because BPA thought it had to comply with statute. *See id.* at 24 ("[T]he treatment of the JOE for demand signal aggregation came as part of the general compromise on issues to reach the final TRM."). PNGC direct provides no evidence to the contrary.

Q. Do you have other concerns with the underlying factual assumptions in PNGC's direct testimony?

A. Yes. In several places in its testimony, PNGC requests BPA to continue the "treatment of PNGC . . . as it has during the current Regional Dialogue contract[.]" Erben, PRDM-26-E-PN-01, at 2. The underlying factual premise of this statement (and others) appears to be the belief that PNGC is being treated in *all respects* under the Regional Dialogue and TRM as a single, aggregated customer. *See id.* at 2 ("[T]he current proposal is to effectively unwind the co-optimization of loads aspect of the JOE by no longer allowing JOE loads to be aggregated for BPA billing purposes. This disaggregation of the JOE serves to undo what the status quo was throughout the Regional Dialogue contract."); *see also id.* ("[A]s represented by current BPA practice, PNGC serves its members as a single preference customer of BPA[.]").

Q. Is this characterization correct?

A. No. While PNGC receives a *single bill* which sums up all the charges associated with its individual members, that bill is made up of charges BPA assesses based on *each* individual PNGC's member's loads. In other words, the current treatment under Regional Dialogue is not to treat PNGC "as a single preference customer." Rather, for every aspect of the TRM *except* demand charges, BPA treats each of PNGC's members as individual utilities and bills PNGC as if they were such. In fact, PNGC's access to Tier 1 Rates and Tier 2 Rates are based on the summation of the individual PNGC members' CHWMs and Above-RHWM Loads. The largest billing determinant on the PNGC bill, the TOCA, which accounts for the majority of the Tier 1 Rate charges on the bill, is a summation of the individual members' TOCAs. The TOCA is also applied to the Non-Slice Rate and any applicable charges or credits associated with the Reserves Distribution Clause. The individual PNGC members' TOCAs are based on the lesser of the individual PNGC member's net requirement or CHWM.

Q. Please provide some examples under the TRM where the individual members of the JOE are called out for purposes of establishing the bill of PNGC.

A. This can best be seen in the application of rate discounts under the TRM, specifically, the Low Density Discount (LDD) and the Irrigation Rate Discount (IRD). We explain the underlying purpose of the LDD and IRD in Beavon and Fisher, PRDM-26-E-BPA-09, at 2-8. Under the TRM, the LDD for the JOE was calculated based on its individual member's benefit. *See* TRM, BP-12-A-03, at 98 ("The LDD benefit to a JOE will be equivalent to the sum of LDD benefits for all eligible individual members of the JOE. BPA will determine the LDD for the JOE based on each such individual utility member's LDD amount."). A similar treatment was provided to the JOE for the IRD. *Id.* at 100 ("The IRMP [Irrigation Rate Mitigation Product, which has since been renamed as IRD in the PRDM] benefit to a JOE will be calculated based on individual utility members and billed to the JOE and earmarked for each eligible utility."). As these references show, under the TRM, the LDD and the IRD are applied to each individual PNGC member that qualifies for the discounts. Those discounts are specifically calculated on the characteristics and energy usage of each *member individually* (not the JOE's members collectively).

As an aside, we note that this treatment makes imminent sense and is consistent with the purposes of these credits. The makeup of PNGC's membership does not increase or decrease the distribution costs or irrigation costs of another member and thus it is appropriate to calculate the need for the LDD or the IRD of each member individually so that the discount continues to flow, unimpacted by unrelated PNGC membership changes, to the retail rates that pay those costs. In a similar way, membership in PNGC does not change BPA's overall obligation to support PNGC members' demand needs, thereby further supporting our proposal for the Tier 1 demand billing determinant for the JOE.

Q. Are there other ways the Regional Dialogue contract views PNGC based on its individual members?

A. Yes. The individualized treatment for PNGC's members is carried forward through several provisions of the Regional Dialogue Contract. For example, in Section 2.79 of PNGC's Regional Dialogue contract it states, "[f]or purposes of this Agreement, 'PNGC's Total Retail Load' (or "Total Retail Load" in reference to PNGC) means the sum of all Members' Total Retail Loads. PNGC does not directly serve retail load." *See* Attachment 3. Therefore, PNGC's Power bill is made up of the summation of each individual PNGC member's metered Total Retail Loads. Every member has a monthly Customer Load Report that accounts for that customer member's metered energy usage for the month. That Customer Load Report also accounts for any Non-Federal Resources within an individual PNGC member's service area that are allowed to offset the member's load for power billing. Those Non-Federal Resources are accounted for by each individual PNGC member in the Regional Dialogue Contract. The total amount of energy that PNGC is billed is a summation of each individual PNGC member's metered loads reduced by those within-service area resources.

In sum, PNGC is incorrect when it claims BPA currently allows the "aggregation and pooling of JOE member loads under the Regional Dialogue contract period and has been recognizing and treating PNGC as the customer of BPA under a single power contract, held on behalf of its members." Erben, PRDM-26-E-PN-01, at 2. While BPA agrees PNGC is the "customer" with BPA under the Regional Dialogue contract, BPA's current practice under Regional Dialogue is to charge PNGC for its individual member's loads in multiple ways, and the PRDM proposal simply extends that current practice to the demand rate.

Q. PNGC also claims that BPA currently allows PNGC to "manage its own load diversity, as every other BPA customer does . . ." and that "every individual BPA customer benefits from the load diversity that exists within its retail customer base (residential, commercial, industrial, etc.) . . . ." Erben, PRDM-26-E-PN-01, at 4. PNGC claims it should be treated no differently. Id. How do you respond?

A. We disagree with PNGC's comparison of itself to an individual utility with a diversified retail load base. First, to be clear, PNGC does not have a "retail customer base . . . ." Erben, PRDM-26-E-PN-01, at 4. Under the TRM and Regional Dialogue contract, the "JOE has no load of its own . . . ." Fisher *et al.*, TRM-12-E-BPA-19, at 5. Instead, the JOE purchases power from BPA "on behalf of its members who are requirements customers of BPA[.]" *Id.* at 4; s*ee also* PNGC's Regional Dialogue Contract, § 2.79 (". . . PNGC does not directly serve retail load.") Those individual member utilities have retail customers that include the features PNGC notes—but those features are not aggregated by virtue of JOE membership, which is a contractual aggregation, or aggregation on paper.

Second, and importantly, the PNGC's "load diversity" does not, in fact, result in any reduction of BPA's costs of serving its individual members. As noted, the load diversity PNGC refers to is a paper aggregation—the load diversity PNGC claims would occur whenever two or more utility loads are considered together. The cost to BPA of standing ready to serve PNGC's members' needs does not change simply because those customers' requirements are administered under a single contract.

To put this into perspective, consider the following: As we understand the facts, by the time the PRDM becomes operative (October 2028), PNGC is expected to hold a contract with BPA for service to 25 utilities, each with its own unique load profile and characteristics. These utilities will be geographically separated into six states (Oregon, Washington, Idaho, Montana, Nevada, Utah), and separated by as much as 700 miles (compare Orcas Power and Light Cooperative (near Bellingham, Washington) to Raft River Rural Electric Cooperative in Utah). *See* Attachment 4. The utilities' topography will also be very different, with some located on islands in the Pacific Ocean, while others are situated in the high desert. Their weather will be different, their geography will be different, their retail consumers will be different, and, ultimately, their peak loads will be different. These unique attributes are not changed because PNGC holds their contract or because they receive one bill. BPA must prepare to meet each of these customers' requirements, and the fact they are members of a JOE does not reduce BPA's costs or responsibilities.

Ultimately, what PNGC is asking for under the PRDM is a special rate treatment that does not apply to any other customer and that does not reflect the costs of serving its members' loads. We do not think it reasonable to give PNGC a reduced billing determinant based on a "paper" diversity benefit that neither reduces the capacity obligations put on BPA by PNGC member loads nor results from any PNGC-specific action taken. Simply put, the presence of the JOE does not reduce the costs BPA incurs to serve the JOE's individual members and changing the billing determinant for demand to assume it does results in a cost shift from PNGC to other customers.

Q. *PNGC claims BPA is reversing "long-standing precedent" with its proposal for billing PNGC based on its members' loads rather than "aggregate JOE member loads for purposes of demand billing." Erben, PRDM-26-E-PN-01, at 5. Do you agree?*

A. No. It was never BPA's intention to place PNGC in a position that provided it a distinct advantage when compared to other customers in terms of rates. Even under the TRM, BPA made clear that "[t]he net result after all the calculations under the TRM should not be different than if there was not a JOE and BPA and the individual utilities were signatories to individual CHWM Contracts." Fisher *et al.*, TRM-12-E-BPA-19, at 5. Our proposal follows this theme through the PRDM's treatment of the JOE.

Q. *Are you saying that there are no potential cost-saving opportunities that could result from PNGC's co-optimization of its members' loads?*

A. No, that is not what we are saying at all. In fact, the diversity of the JOE members' loads described above does provide some commercial cost-saving opportunities to PNGC and its members due to increased economies of scale. Those commercial benefits, however, exist and are available to PNGC and its members regardless of the base from which the PRDM measures the Tier 1 demand charge billing determinant. Nothing in the PRDM's proposal requires, or even implies, that PNGC change the way it optimizes member loads at scale. The PRDM simply changes the base from where to measure for all PF Public loads (by removing Contract Demand Quantities (CDQs) and changing the measurement to be monthly rather than during the Heavy Load Hours only) while still providing the same long-run marginal cost price signal that PNGC can optimize to by investing in capacity-reducing initiatives in any of its members' service territories. Said another way, a capacity asset has the same value to PNGC and its members under PRDM that it did under TRM. Consistent with this fact, PNGC's testimony provides no evidence of how a PNGC load optimization and asset investment action is in some way unwound by the PRDM's approach to measuring the Tier 1 demand charge billing determinant relative to the TRM's approach.

Q. *You mention above that BPA proposed the RICj to partially mitigate the cost impact to PNGC as it transitions from the TRM to the PRDM. Did PNGC have comments on that aspect of your proposal?*

A. Yes. PNGC is in "strong support" of our proposal to recognize and attempt to remediate the financial impacts of changing from the demand charge treatment under TRM to the demand charge treatment under PRDM. Erben, PRDM-26-E-PN-01, at 3. However, they do not believe the RICj goes far enough and offer other proposals.

Q. *What does PNGC suggest as an alternative to your proposal on the RICj?*

A. One option they propose is to treat the RICj like the RICc and remove the phaseout component of the RICj. Erben, PRDM-26-E-PN-01, at 4. PNGC contends that this approach is the "appropriate path for rate mitigation because the financial harm from this PRDM proposal is directly associated with the amount of capacity being exposed to the marginal demand charge and BPA is increasing this amount more for the JOE than for other customers." *Id.* at 5.

Q. *What is your response?*

A. We disagree. The PRDM made many rate design changes in relation to TRM that will cause changes to the amount of revenue collected from every customer. The change in the way the Tier 1 demand billing determinant is calculated for the JOE is just one of many other rate design changes that will cause effective rate impacts. Like other impacts, such as the removal of CDQs that directly impact every customer's Tier 1 demand billing determinant, these will be transitioned over time, to mitigate rate-shock from TRM to PRDM. As its name implies, the Rate Impact Credit for the JOE (RICj) has a corollary, and that corollary is the Rate Impact Credit for *Mitigation* (RICm). The rationale for phasing out the RICm applies the same to the RICj in that its purpose is to gracefully transition to the new rate design.

This is unlike the RICc, which is designed to ensure an embedded cost of capacity is paid for existing capacity needs while simultaneously allowing the PRDM to apply a long-run marginal price signal to a customer's entire demand billing determinant.

Q. What else does PNGC recommend?

A. PNGC also asks that we "maintain[] the proposed RICj mitigation tool to mitigate the negative financial impact of the policy change being proposed[.] PNGC, at a minimum, respectfully requests that BPA not truncate the period over which the financial impact is calculated by excluding Regional Dialogue Contract years after 2023. The Regional Dialogue contract period in its entirety should be considered in determining the appropriate financial harm and associated rate credit for calculating the bill credit . . . ." Erben, PRDM-26-E-PN-01, at 4.

Q. Did you understand what PNGC is requesting?

A. No. PNGC's testimony did not state exactly what adjustments to the RICj it was seeking. As we noted earlier, our proposal for the RICj provided an initial mitigation payment of $1 million in FY 2029, tapering down to $0 in 2044, with a total of $8 million in RICj mitigation payments to PNGC. We asked for more specifics on PNGC's proposal in the attached Data Request, BPA-PN-40-1 (*see* Attachment 5), and PNGC clarified that they propose BPA replace the RICj table in the PRDM with a new table that holds the $1 million initial value flat over the entirety of the Provider of Choice Contract period (*i.e.*, FY 2029-2044). The total value PNGC seeks, then, is $16 million (double the proposed RICj).

Q. What is your response?

A. We do not agree with PNGC's alternative RICj value. To begin, we would like to recap how we reached the RICj value and its taper-off feature. As explained in our direct testimony, the TRM attempted to place the JOE on roughly the same footing as other customers. Reed *et al.*, PRDM-26-E-BPA-05 at 23-24. The "value" that PNGC received under the TRM through its treatment of demand billing determinants—which we view as incidental rather than intentional—was around $1 million. This value, however, was not guaranteed and was a byproduct of the complicated relationship between demand billing determinants and CDQs. With the removal of CDQs, and the adoption of more transparent pricing for capacity and demand under the PRDM, it is reasonable to establish demand billing determinants that are uniform across all customers.

Our proposal mitigates this transition and builds from analysis that replicated the value PNGC received originally under the TRM. *See* Reed *et al.*, PRDM-26-E-BPA-05, at 22-27. The RICj is built from, for lack of a better phrase, the value BPA knew or should have known was the cost of the "compromise" for the TRM. That compromise is now over, and we are embarking on a new methodology with new rates. As a matter of equity and mitigating rate shock, we've designed the RICj to start at the same level as that original TRM compromise ($1 million) but then taper it off over the ensuing 16 years to $0. The fact that our proposal tapers off to $0 is an important part of the balance that holds together the compromise behind the PRDM. By proposing the RICj we are, in part, perpetuating the unintentional cost shift in the TRM between customers for another 16 years. However, this is largely palatable because it is not forever. It has a beginning and an end, and by the end of the Provider of Choice Contract, PNGC (and its members) will be in the same place as every other customer under the PRDM. This aligns our proposal with the TRM's intent, to which we still agree, that the PRDM "place the JOE in roughly the same position as other customers." Reed *et al.*, PRDM-26-E-BPA-05 at 16.

Q. PNGC also requests that BPA not "truncate the period over which the financial impact is calculated by excluding Regional Dialogue Contract years after 2023." Erben, PRDM-26-E-PN-01, at 4. How do you respond to PNGC's recommendation?

A. PNGC appears to be requesting that BPA determine the total value that PNGC received from the TRM since its original development. Principally, we disagree that the PRDM should attempt to mitigate for other impacts that may have occurred well after the TRM was established. To the extent the TRM had an implicit cost shift at its formation, we are willing, as a matter of equity and rate shock, to mitigate that for a period of time. Beyond that, we believe it inequitable to attempt to make permanent unintended benefits that may have resulted during the term of the TRM. The PRDM builds on the TRM and further improves it rather than locks in forever outcomes for which were neither expected nor justified.

Further, PNGC's claim for a larger RICj does not seem to be supported by any analysis of whatever harm it claims to have. It seems to simply be our initial valuation with no taper. That feature of PNGC's proposal we strongly oppose as it would be perpetuating the TRM cost shift into the future. The schedule PNGC proposes, which is a flat $1 million a year for the term of the Provider of Choice contract, is, in effect, codifying the cost shift from the TRM into the PRDM, with no sunset. Thus, at the end of the Provider of Choice contract, the "cost shift" issue that exists today under the TRM and the Regional Dialogue contract could continue into the next iteration of rates and agreements. The same equity questions of moving PNGC and its membership to a level playing field with other customers will again be debated. We think two generations of contracts and rates with implicit (TRM) and now explicit (PRDM) costs shifts are enough.

Q. Does PNGC have other suggestions?

A. Yes. If BPA does not support either of those changes, PNGC contends we should "at a minimum" provide a "bill credit commensurate with other financial losses resulting to BPA customers from currently proposed policy changes." Erben, PRDM-26-E-PN-01, at 4-5. PNGC contends that the current RICj provides a credit of "less than half of the total potential losses compared to the current contract." *Id.* at 5.

Q. How do you respond?

A. What PNGC appears to be arguing is that it is incurring lost value in not only the TRM-PRDM transition but also in other BPA policy decisions, and as such, believes the PRDM should be the means of addressing for it and others. We disagree. The PRDM is not designed to be the financial neutralizer of all policies and rate changes occurring with the transition from the TRM and Regional Dialogue to PRDM and Provider of Choice. As we explained above, and throughout our testimony, the PRDM is a carefully crafted compromise that most customers support. Each customer and customer group is giving up some value to achieve the holistic, transparent, and reasonable results offered by the PRDM. Part of that compromise is built from the RICj component of our proposal. If PNGC pulls that thread, other features of the PRDM will need to change, as customers that pay for these costs will inevitably raise their own cost shift and rate shock issues. Our proposal, in contrast, is properly tailored to address a specific, identified, and quantifiable issue that arises as we consider the position of PNGC under TRM and PNGC under PRDM.

Section 10: PRDM Supplemental Changes—Energy-Rates and Cost Pool Issue

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

A. In the time between our PRDM Initial Proposal and this rebuttal testimony, we discovered an error in the way the PRDM proposed to apply energy shapes (*e.g.*, HLH and LLH by month) to the Tier 1 energy rates. Specifically, in the Initial Proposal, we proposed to apply an energy shape to the Tier 1 Composite Energy Rates and have a single Tier 1 Non-Slice Energy Rate. After further evaluation of this approach, we realized this created an inadvertent mismatch between where the costs of serving differently shaped loads would be allocated (to the Non-Slice Cost Pool) and where the revenue from each customer would be allocated (to the

Composite Cost Pool). Hence, we are proposing to fix this oversight through adjustments to the PRDM as described in this rebuttal testimony.

Q. How do you propose to address the issue you identify above?

A. The problem can be resolved by removing the energy shape from the Tier 1 Composite Energy Rates and applying the energy shape to the Tier 1 Non-Slice Energy Rates instead. This will result in a single Tier 1 Composite Energy Rate each year and multiple Tier 1 Non-Slice Energy Rates each year. The opposite application, the problematic one, was proposed in the Initial Proposal where there would be multiple Tier 1 Composite Energy Rates and a single Tier 1 Non-Slice Energy Rate. Further, to aid in understandability, clarity, and intuition, we also propose to embed the Tier 1 Composite Energy Rate into the calculation of the Tier 1 Non-Slice Energy Rates as well as make clear the flexibility to decide in each 7(i) Process to have monthly rates for each fiscal year or monthly rates applicable for the entire Rate Period.

Q. Is there another way you could explain our understanding of why this fix is needed?

A. Sure. Given people's familiarity with the TRM, we will use that to demonstrate how our proposed fix aligns the PRDM approach with the proven TRM approach. Both the PRDM and the TRM correctly allocate secondary revenues and balancing purchases to the Non-Slice Cost Pool. This Non-Slice Cost Pool allocation is done so that the cost and benefits of serving load shapes is allocated to the customers that purchase power in a shape different from that of the shape of the Tier 1 System Resources output. Consistent with this approach, the TRM applies a Load Shaping Charge to Non-Slice loads and allocates the revenue collected from that charge to the Non-Slice Cost Pool. This matching allocation aligns the cost of serving more expensive load shapes, which results in reduced secondary revenue or increased balancing purchase costs, with increased revenue from the customer causing that increased cost. This is the appropriate approach and aligns the rate design with cost causation.

Now to the PRDM. The intent of the PRDM was to apply the same proven approach used in the TRM but the PRDM inadvertently lost its way when it applied an energy shape to the Tier 1 Composite Energy Rates instead of the Tier 1 Non-Slice Energy Rates. This effectively bundled the impact of the Load Shaping Charge into the Tier 1 Composite Energy Rates instead of bundling the Load Shaping Charge into the Tier 1 Non-Slice Energy Rates. Unchanged, this would create a mismatch by allocating the costs of meeting different load shapes to the Non-Slice Cost Pool while allocating the offsetting revenue impacts to the Composite Cost Pool. The presence of this mismatch is the reason we are proposing a fix that correctly matches the cost allocation with the revenue collection.

Q. Does this change substantively affect any aspect of the PRDM's cost allocation?

A. No. In fact, this change ensures the cost allocation aligns with our original intent and the proven cost allocation and revenue collection included in the TRM.

Q. Where are the specific edits you propose to make?

A. The specific edits we propose are provided in Attachment 6, and incorporated into the larger redline of the PRDM (Attachment 1) we filed with our testimony.

Q. Did you have an opportunity to share this proposal with parties before submitting this testimony? If so, what was their response?

A. BPA shared these edits at a publicly noticed meeting prior to filing this testimony. We gave parties until February 7, 2025, to provide us with some preliminary reactions or concerns to these changes. We received a few suggestions, but no objections and no concerns with the overall approach.

Q. This change is coming late in the process. If parties have concerns with this approach, how can they make those known?

A. We recognize that this change is coming late in the PRDM 7(i) Process. While we believe these changes simply align the PRDM with our original intent, we want to ensure parties to this proceeding have an opportunity to respond to these changes. As such, BPA has filed a motion to amend the procedural schedule to allow parties to file surrebuttal testimony to this aspect of our testimony.

Q. Does this conclude your testimony?

A. Yes.

ATTACHMENTS

Attachment 1: PRDM redline (all changes since Initial Proposal). Filed under separate cover.

Attachment 2: 2029 PRDM Workshop Closeout Table Showing Draft 1 to Initial Proposal PRDM Changes

Attachment 3: Total Retail Load Definition from PNGC's Regional Dialogue Contract

Attachment 4: Map of PNGC's Members

Attachment 5: Data Response from PNGC

Attachment 6: Draft Proposed PRDM Changes for Rebuttal—Energy Charge Fix.

Attachment 7: PRDM Appendix F—RICc Example Calculation

Attachment 1

PRDM Redlines from Initial Proposal

Filed separately

Attachment 2: Draft 1 to Initial Proposal PRDM Change

General message from PA Staff: Based on a careful review of the comments, we have made several changes to the Draft 1 PRDM. The PRDM has been well built through hard work, transparent compromise, and contains wins and tradeoffs for all parties. We believe the Draft 1 PRDM, with these changes, represents a robust and balanced package.

It is BPA Staff's intent to discuss these changes to the Draft 1 PRDM at the workshop on October 8, 2024, and following that discussion, consider including these additions in the Initial Proposal for the PRDM proceeding.

Topic	Draft 1 PRDM	Initial Proposal PRDM
Demand Rate Adjustment Cap	Monthly up only 5% rate period cap.	Monthly 10% rate period limiter (up and down).
RICm	Annual 0.10 mills/kWh phase out.	Rate Period 0.15 mills/kWh phase out.
RICm		Clarification. Add the following sentence to the end of first paragraph of RICm section. "The RICm will also not include the Peak Load Variance Charge for Block customers."
RICc	No RICc recalculation for product changes.	No change for customers that elect the Load Following Product or take a Block Product that requires a Peak Net Requirement (PNR) check. Customers that are not required to undergo a PNR check can elect a voluntary PNR check at contract signing. In exchange the customer's RICc would be calculated using its FY2029 weather-normalized loads consistent with the results of the PNR check as established through a 7(i) Process.
RICc	No RICc adjustment for Demand Response actions taken between 2025 and 2028.	Leave open the ability to adjust, at BPA's sole discretion, a customer's RICc for Demand Response actions taken between 2025 and 2028 that can be quantifiably demonstrated to have changed the customers BP-29 Rate Case forecast or its FY2029 actual weather-normalized loads as established through a 7(i) Process.

Topic	Draft 1 PRDM	Initial Proposal PRDM
Peak Load Variance Charge	The PRDM did not specify how the PLVS capacity amounts would be determined, but the intent was to not double count.	Make clear that the capacity amounts used to calculate the PLVC would be adjusted downward for planning capacity costs recovered through other charges, such as Operating Reserves.
Peak Load Variance Charge	Rate construct not specified.	PLVC for Load Following Product calculated using a single mills/kWh rate. PLVC rate construct for Block Product to be decided in each 7(i) Process.
Peak Load Variance Charge		Clarify intent by adding following sentence: "The PLVC for the Load Following Product recovers the cost of holding capacity for load excursions outside BPA's expected P50 peak load forecast up to BPA's P10 peak load forecast."
Peak Load Variance Charge	The PRDM allowed for different billing determinants and rates for the PLVC for Block and Load Following customers.	The PRDM will add the following a parenthetical to the existing language to make this flexibility clearer. "The billing determinants and rates used to calculate the PLVC will be established in each 7(i) Process and may be different as between the Load Following product and the Block product if planning, access to and use of PLVS capacity is determined to be materially different across the products **(*i.e.*, the cost of PLVC will be set commensurate with the service provided)**.
Required Support Services for Existing Resources	Capacity costs based on marginal cost of capacity.	Capacity cost based on embedded cost of capacity. (see Attachment B diagram below)
Disaggregation of Risks within Tier 1 Non-Slice Products	Prohibition for entire PRDM term with public process to discuss in FY 2040-2041.	Prohibition until FY 2041 for PF Public Customers with CHWM Contracts. Parties to Rate Cases setting rates for FY 2041 and beyond can propose in the applicable 7(i) Process that BPA disaggregate the allocation of risk to Non-Slice Products. Commitment to additional public process removed.
Marginal Energy True-Up	Applicable to all products.	Applicable to all products but add a fourth purpose. "4) in the case of the Slice Product, affords BPA the ability to streamline, or removal entirely, a Requirement Slice Output (RSO)-like test as established through the Slice contract."
Marginal Energy True-Up	No mention of payment schedule.	Add: "The final Marginal Energy True-Up for each customer shall be applied as a three-month charge spread equally across the three months following the month the final Marginal Energy True-Up Charge is determined by BPA. BPA will pay any amounts owed to the customer in a single first-month bill credit. No interest shall be applied."
Rate Mitigation associated with	No JOE-specific Rate Mitigation	Addition of a RICj that accounts for the rate design impact of changing the calculation of the Demand Charge for JOE members. The aggregate stream of

Topic	Draft 1 PRDM	Initial Proposal PRDM
design change that removes aggregated demand billing determinant for a JOE		RICj credits are provided in the table below and are grounded on the inadvertent value BPA anticipated the JOE would realize under TRM as a Load Following customer. The value was understood as sometimes the JOE would pay less and sometimes the JOE would pay more with the aggregated Demand Charge under the TRM, but overall, the aggregated demand combined with smaller CDQs was anticipated to produce about a $1 million a year value for the JOE. The stream of credits, specified below, would apply if PNGC were to elect the Load Following Product and would be an October bill credit. PNGC would choose how to spread the payments among its members. The cost of the RICj would be allocated to the Non-Slice Cost Pool and would not impact any customer's Marginal Energy True-Up Rate.

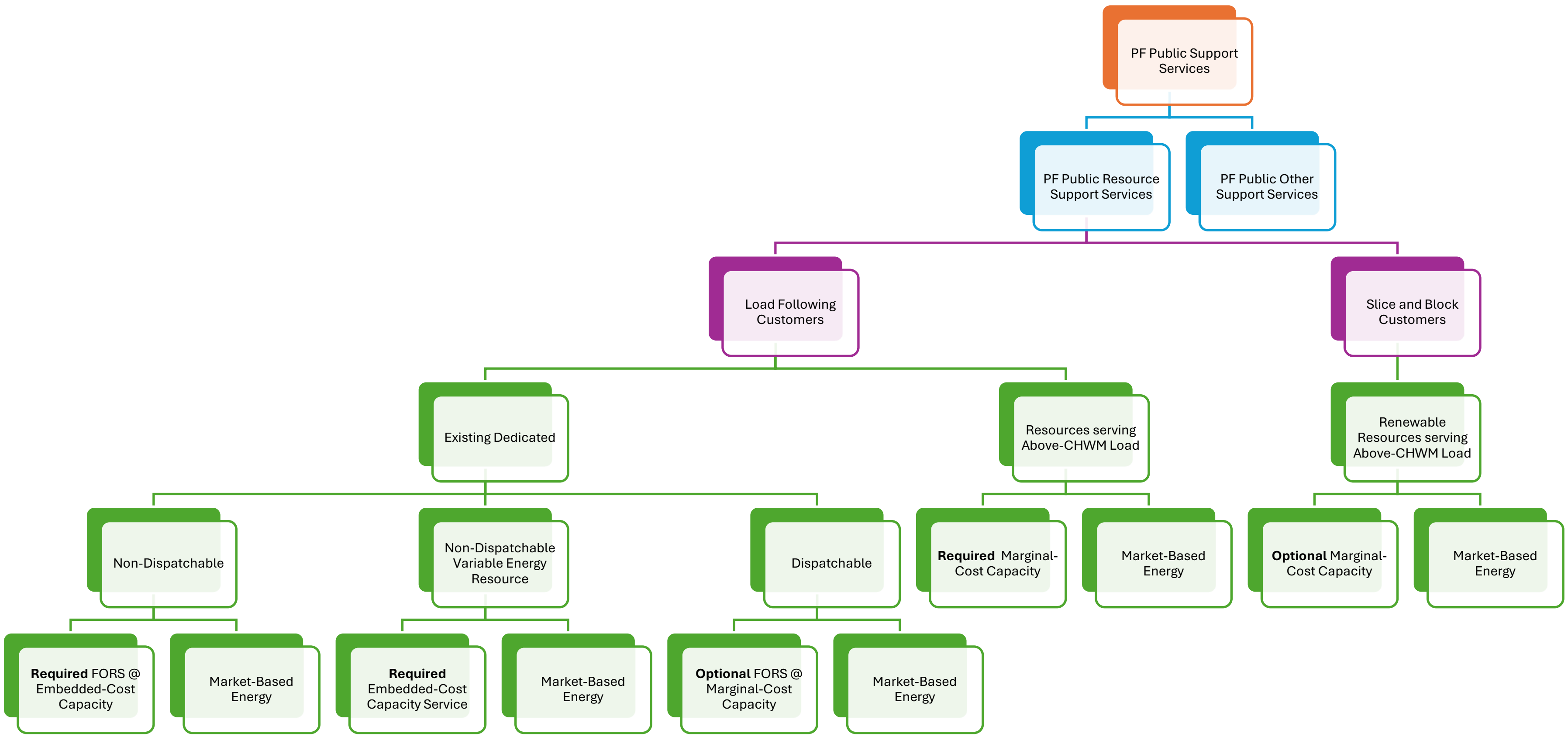
	RICj Value
2029	$1,000,000
2030	$ 933,333
2031	$ 866,667
2032	$ 800,000
2033	$ 733,333
2034	$ 666,667
2035	$ 600,000
2036	$ 533,333
2037	$ 466,667
2038	$ 400,000
2039	$ 333,333
2040	$ 266,667
2041	$ 200,000
2042	$ 133,333
2043	$ 66,667
2044	$ 0
Total Value	$8,000,000

Topic	Draft 1 PRDM	Initial Proposal PRDM
Up to 0.999 aMW Operational Convenience to use the Core Rate Design for load that would otherwise be Above-CHWM Load.	Specific about intent, but not specific with how this would or would not apply to a JOE.	The intent of the 0.999 aMW provision is to provide operational convenience to align with lumpy non-Federal resource shapes and whole MWh schedules. A JOE is not required to schedule or manage Above-CHWM Load by member, and thus the JOE will inherently enjoy the operational convenience intended by this provision in the PRDM the same as others. The PRDM will make clear the application of the JOE, which will be that the 0.999 aMW is applied to the JOE.
Tier 2 Long-Term Change Fee	Shall be no lower than 0.05 mills/kWh applied to Tier 1 Load for the remaining term of the CHWM Contract.	Shall be no lower than 0.05 mills/kWh and no higher than 0.10 mills/kWh, as established in each 7(i) Process, applied to Tier 1 Load for the Rate Period immediately following the election.
Tier 2 Rates		Clarify the intent that power sold at Tier 2 rates would include the cost of meeting resource planning requirements at the marginal cost of meeting those requirements. Similarly, clarify that any additional capacity services provided as a part of serving all Above-CHWM Load would be at marginal-cost capacity.
Existing Capacity Credit	Energy credited at Tier1 Composite Energy Rates	Change Tier 1 Composite Energy Rates to market-based rates. See new PRDM Attachments A & B for a complete overview.
Other Tier 1 Charges	Includes a potential example of how conservation costs could be collected from customers.	Remove example.
Tier 1 System Resources		Add clarity to the section and a "Resource Type" to the resource tables.

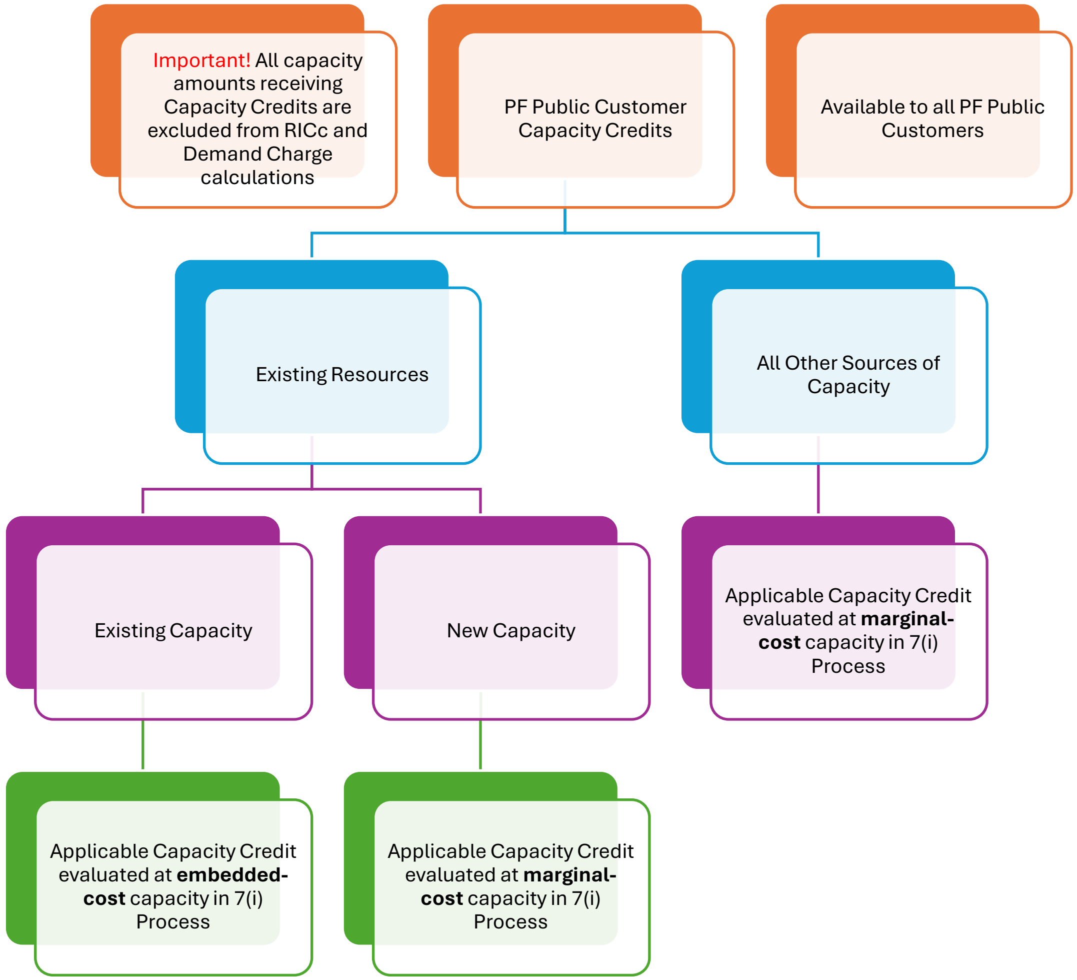
Topic	Draft 1 PRDM	Initial Proposal PRDM
Firm Surplus and Secondary Adjustment	"BPA may also propose in a 7(i) Process that portions of the Tier 1 Secondary Energy Credit be reallocated to Composite Cost Pool as supported by Section 2.1, such as when a market, operational, or other decision causes a portion of the advanced sale of secondary associated with the Slice Product to otherwise be credited to the Non-Slice Cost Pool."	No change. We believe this language provides sufficient flexibility to reallocate Tier 1 Secondary Energy Credits to the Composite Cost Pool if supported by the principles listed in Section 2.1. This would apply in situations where the Federal system is larger than CHWMs and situations where a Day Ahead Product or a Day Ahead Market causes additional value to fall into the Non-Slice Cost Pool that should be reallocated to the Composite Cost Pool.
Chapter 9 Customer Group	Customer Group means a group comprised of not less than 45 percent of the Customers (utility count).	Customer Group means a group comprised of (1) not less than 45 percent of the Customers (utility count), *or (2) not less than 45 percent of the sum of the CHWMs.*
Chapter 9 Revisions to accommodate DA market	Not explicitly called out. Revisions could fall into various categories.	Revisions to accommodate DA market participation will follow process for Unintended Consequences that Do Not Affect Others, except for revisions for Cost Recovery or Court Ruling, or Unintended Consequences that Do Affect Others (which will follow their respective processes).
Chapter 9 Irreconcilable Conflict	May allege BPA final action is in Irreconcilable Conflict with PRDM	BPA will add: May allege BPA final action *or inaction* is in Irreconcilable Conflict with PRDM.
Chapter 9 Irreconcilable Conflict	If Administrator determines Irreconcilable Conflict, "BPA will take all practicable steps to revoke…"	If Administrator determines Irreconcilable Conflict, "BPA will take all *necessary steps within its authority* to revoke…"

Topic	Draft 1 PRDM	Initial Proposal PRDM
General Cleanup		Thank you for the help in editing the document. We plan to adopt the cleanup edits provided to the Draft 1 PRDM. We will also be adding other cleanup edits that BPA Staff have found as well.
BPA Commitment		Not included in the PRDM, but BPA commits to creating PRDM-style rates using the BP-26 Final Proposal to help customers prepare to sign the PoC CHWM Contract.

Proposed PRDM Attachment B



Proposed PRDM Attachment C



Attachment 3

Total Retail Load Definition from PNGC's Regional Dialogue Contract

2.79 "Total Retail Load" means all retail electric power consumption, including electric system losses, within a PNGC Member's electrical system excluding:

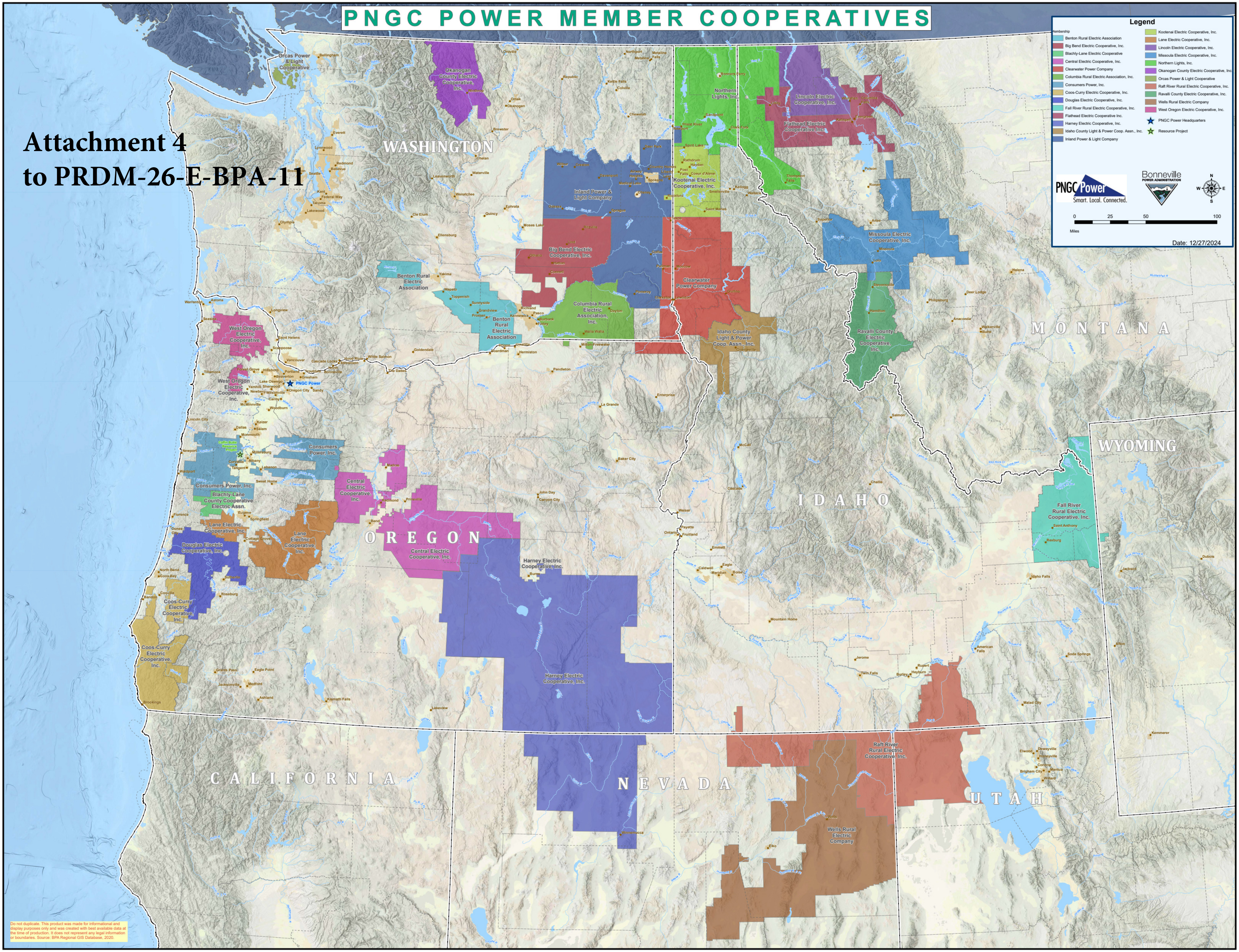
(1) those loads BPA and PNGC have agreed are nonfirm or interruptible loads,

(2) transfer loads of other utilities served by that PNGC Member, and

(3) any loads not on that PNGC Member's electrical system or not within that PNGC Member's service territory, unless specifically agreed to by BPA.

For purposes of this Agreement, "PNGC's Total Retail Load" (or "Total Retail Load" in reference to PNGC) means the sum of all Members' Total Retail Loads. PNGC does not directly serve retail load.

Attachment 4 to PRDM-26-E-BPA-11



Attachment 5

UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
BEFORE THE
BONNEVILLE POWER ADMINISTRATION

2026 PRDM PROCEEDING) BPA Docket No. PRDM-26

DATA RESPONSE OF

PACIFIC NORTHWEST GENERATING COOPERATIVE

Data Request BPA-PN-40-1 Details

Primary Filing Code	PRDM-26-E-PN-01
Request Code	BPA-PN-40-1
Requesting Party	Bonneville Power Administration
Request Directed To	Pacific Northwest Generating Cooperative
Page Number	4
Line Number	15
Requested Date	1/23/2025 3:06:57 PM
Description	Please clarify the meaning of 'modeled as a RICc not a RICj' (PRDM-26-E-PN-01 Page 4, Line 15), specifically whether: (A) PNGC is proposing an alternative calculation of the RICc and removal of the RICj, or (B) PNGC is proposing that the RICc remain unchanged but have the RICj function like the RICc by not tapering off over time. If (A), please provide the RICc formula that PNGC proposes the PRDM use and confirm that the RICj would be removed under this proposal. If (B), please confirm that the RICc would remain unchanged and provide the PNGC proposed replacement for Table 4-1 in the PRDM titled the Rate Impact Credit for the JOE Schedule and how that would or would not impact 2045.

<u>RESPONSE:</u>

PNGC is proposing that the RICc remain unchanged but have the RICj function like the RICc by not tapering off over the course of the Provider of Choice contract. The payment stream associated with the Provider of Choice contract period through 2044 is as set out in the table below. PNGC has not performed any analysis regarding what would be appropriate for a preference customer contract beyond the period of the upcoming Provider of Choice contract.

Fiscal Year	RICj Amount
2029	$1,000,000
2030	$1,000,000
2031	$1,000,000
2032	$1,000,000
2033	$1,000,000
2034	$1,000,000
2035	$1,000,000
2036	$1,000,000
2037	$1,000,000
2038	$1,000,000
2039	$1,000,000
2040	$1,000,000
2041	$1,000,000
2042	$1,000,000
2043	$1,000,000
2044	$1,000,000

OBJECTION:

To the extent the question calls for analysis that PNGC has not performed, PNGC objects pursuant to Rule 1010.12(b)(1)(ii).

SPONSOR:

Erin Erben, Chief Operating Officer, PNGC (Response)

Counsel (Objection)

DATE:

January 29, 2025

Attachment 6

Draft Proposed PRDM Changes for Rebuttal—Energy Charge Fix

4.1.2 Tier 1 Composite Energy ~~Rates~~Rate

BPA will establish ~~Tier 1 Composite Energy Rates~~ in each 7(i) Process~~. Tier 1 Composite Energy Rates are~~ either: 1) a Tier 1 Composite Energy Rate for each year of the Rate Period, or 2) a single Tier 1 Composite Energy Rate for the Rate Period. In either case, the Tier 1 Composite Energy Rate will be calculated as a single monthly rate to collect costs allocated to the Composite Cost Pool and is applicable to the Load Following, Block and Slice Products (mills/kWh). For the Load Following and Block Products, the Tier 1 Composite Energy ~~Rates will be calculated to recover costs and credits allocated to the Composite Cost Pool and~~Rate will be ~~shaped across the year, using a fixed scalar (mills/kWh)~~combined into and ~~expected market-based prices as determined~~recovered from Tier 1 Non-Slice Energy Rates as discussed in ~~each 7(i) Process. The Tier 1 Composite Energy Rates can be positive or negative values.~~

~~BPA will use a Monthly/Diurnal market-based price to shape its Energy Rates (*i.e.*, one HLH and one LLH for each of the 12 months for a total of 24 market-based prices each year) unless BPA develops a different market-based price approach in a 7(i) Process (for example, more or less granular).~~

~~Prior to shaping, the annual average equivalent of~~Section 4.1.3 below. For the Slice Product, the Tier 1 Composite Energy Rate ~~is equal to:~~will serve as a standalone flat rate across the year.

If BPA establishes a Tier 1 Composite Energy Rate for each year of the Rate Period, BPA will use the following formula:

$$T1CompositeEnergyRate = \frac{CCP_F}{\Sigma T1EBD_F}$$

where:

$T1CompositeEnergyRate$ = the ~~annual average equivalent of the~~ Tier 1 Composite Energy ~~Rates,~~Rate expressed in mills/kWh~~, before being shaped, using a fixed scalar, to the market-based price as established in each 7(i) Process~~.

CCP_F = the forecast total annual expenses and revenue credits in the applicable Fiscal Year of the Rate Period allocated to the Composite Cost Pool

~~$T1EBD_F$~~$\Sigma T1EBD_F$ = sum of forecast Tier 1 Energy Billing Determinants for Load Following, Block, and Slice Products in kWh

If BPA establishes a single Tier 1 Composite Energy Rate for the Rate Period, such rate will be calculated using the costs allocated to the Composite Cost Pool for the Rate Period in the numerator and the applicable Tier 1 Energy Billing Determinants for the Rate Period in the denominator.

4.1.3 Tier 1 Non-Slice Energy ~~Rate~~Rates

BPA will establish ~~a Tier 1 Non-Slice Energy Rate~~ in each 7(i) Process~~. The~~ either: 1) a set of Tier 1 Non-Slice Energy Rates for each year of the Rate Period, or 2) a single set of Tier 1 Non-Slice Energy ~~Rate is a rate applicable to the Load Following and Block Products~~Rates for the Rate Period. In either case, the Tier 1 Non-Slice Energy Rates (mills/kWh~~). The Tier~~

~~1 Non-Slice Energy Rate~~) will be calculated to recover costs and credits allocated to the Non-Slice Cost Pool and will be ~~a single annual rate.~~combined with the Tier 1 Composite Energy Rate as discussed in Section 4.1.2 above. The Tier 1 Non-Slice Energy ~~Rate~~ Rates are applicable to the Load Following and Block Products. Tier 1 Non-Slice Energy Rates will be shaped across the year using a fixed scalar (mills/kWh) addition or subtraction from expected market-based prices as determined in each 7(i) Process. The Tier 1 Non-Slice Energy Rates can be ~~a~~ positive or negative ~~value~~values.

BPA will use a Monthly/Diurnal market-based price to shape the Tier 1 Non-Slice Energy Rates (*i.e.*, one HLH and one LLH for each of the 12 months for a total of 24 market-based prices each year) unless BPA develops a different market-based price approach in a 7(i) Process (for example, more or less granular).

If BPA establishes a set of Tier 1 Non-Slice Energy Rates for each year of the Rate Period, the following formula is equal to the annual average equivalent of the Tier 1 Non-Slice Energy prior to shaping.

$$T1NonSliceEnergyRate = \cancel{\frac{NSCP_F}{\Sigma T1EBD_{F.NS}}} \frac{\left(NSCP_F + (T1CompositeEnergyRate \times \Sigma T1EBD_{F.NS})\right)}{\Sigma T1EBD_{F.NS}}$$

where:

T1NonSliceEnergyRate = the annual average equivalent of the Tier 1 Non-Slice Energy Rates, expressed in mills/kWh, before being shaped, using a fixed scalar, to the market-based price as established in each 7(i) Process

$T1CompositeEnergyRate$ = the Tier 1 Composite Energy Rate expressed in mills/kWh

~~$NSCP_{F.F}$~~ $=NSCP_F =$ the forecast total annual expenses and revenue credits in the applicable Fiscal Year of the Rate Period allocated to the Non-Slice Cost Pool

$\Sigma T1EBD_{F.NS}$= sum of forecast Tier 1 Energy Billing Determinants for Load Following and Block Products in kWh

~~Tier 1 Slice Energy Rate~~

If BPA establishes a single set of Tier 1 Non-Slice Energy Rates for the Rate Period, such rates will be calculated using the costs allocated to the Non-Slice Cost Pool and the Composite Cost Pool for the Rate Period in the numerator and the applicable Tier 1 Energy Billing Determinants for the Rate Period in the denominator.

4.1.4 Tier 1 Slice Energy Rate

BPA will establish ~~a Tier 1 Slice Energy Rate~~ in each 7(i) Process~~. The~~ either: 1) a Tier 1 Slice Energy Rate ~~is applicable to~~for each year of the ~~Slice Product (mills/kWh). The~~Rate Period, or 2) a single Tier 1 Slice Energy Rate for the Rate Period. In either case, the Tier 1 Slice Energy Rate will be calculated as a single monthly rate to ~~recover~~collect costs ~~and credits~~ allocated to the Slice Cost Pool and ~~will be a single rate annual rate.~~ applicable to the Slice Products (mills/kWh). The Tier 1 Slice Energy Rate can be a positive or negative value.

If BPA establishes a Tier 1 Slice Energy Rate for each year of the Rate Period, BPA will use the following formula:

$$T1SliceEnergyRate = \frac{SCP_F}{\Sigma T1EBD_{F.S}}$$

where:

$T1SliceEnergyRate$ = the Tier 1 Slice Energy Rate expressed in mills/kWh

SCP_F = the forecast total annual expenses and revenue credits in the applicable Fiscal Year of the Rate Period allocated to the Slice Cost Pool

$\Sigma T1EBD_{F.NS}$= sum of forecast Tier 1 Energy Billing Determinants for the Slice Product in kWh

If BPA establishes a single Tier 1 Slice Energy Rate for the Rate Period, such rate will be calculated using the costs allocated to the Slice Cost Pool for the Rate Period in the numerator and the applicable Tier 1 Energy Billing Determinants for the Rate Period in the denominator.

4.2.3 Tier 1 Marginal Energy True-Up Rate

A customer's Tier 1 Marginal Energy True-Up Rate is the mills/kWh difference between a flat annual block of power purchased from BPA: 1) at its Tier 1 energy rates applicable to the Non-Slice Product, including a customer's Low Density Discount (LDD), RICc and RICm, and 2) the same amount of power had it been purchased at a market-based price. The Tier 1 Marginal Energy True-Up Rate can be negative or positive, and is specific to each customer. The market-based price will be established in each 7(i) Process. The formula BPA will use to calculate the customer's Marginal Energy True Up Rate is as follows:

$$METU_R = FB_{MKT} - \cancel{\{([FB_{COMP} + NS_R] \times [1 - LDD]) + RIC_C + RIC_M\}}\{(FB_{NS} \times [1 - LDD]) + RIC_C + RIC_M\}$$

where:

$METU_R$= a customer's Tier 1 Marginal Energy True Up Rate expressed in mills/kWh for a Fiscal Year

FB_{MKT} = the mills/kWh market price of a flat annual block of power as established in each 7(i) Process

~~FB_{COMP}~~FB_{NS} = mills/kWh cost of a flat annual block of power purchased at BPA's Tier 1 ~~Composite Energy Rates~~

~~NS_R = the Tier 1~~ Non-Slice Energy ~~Rate expressed in mills/kWh for a Fiscal Year~~Rates

LDD = a customer's Low Density Discount applicable to the Fiscal Year subject to the Tier 1 Marginal Energy True-Up

RIC_C= a customer's RICc for the Fiscal Year subject to the Tier 1 Marginal Energy True-Up expressed in mills/kWh

RIC_M = a customer's RICm for the Fiscal Year subject to the Tier 1 Marginal Energy True-Up expressed in mills/kWh

Attachment 7

PRDM Appendix F—RICc Example Calculation

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Month	October	November	December	January	February	March	April	May	June	July	August	September
2	FY2029 Hours	744	721	744	744	672	743	720	744	720	744	744	720
3	FY2030 Hours	744	721	744	744	672	743	720	744	720	744	744	720
4	Example Demand Rate ($/kW/mo)	15.21	11.88	14.31	13.09	13.65	8.78	6.71	2.58	4.53	15.32	16.16	18.18
5	Example Embedded Cost of Capacity - ECC ($/kW/mo)	6.49	5.07	6.1	5.58	5.82	3.74	2.86	1.1	1.93	6.53	6.89	7.75
6	FY2029 Tier 1 Energy (kWh)	63,240,000	61,285,000	66,960,000	70,680,000	60,480,000	63,155,000	57,600,000	59,520,000	54,000,000	63,240,000	66,960,000	68,400,000
7	FY2030 Tier 1 Energy (kWh)	66,402,000	64,349,250	70,308,000	74,214,000	63,504,000	66,312,750	60,480,000	62,496,000	56,700,000	66,402,000	70,308,000	71,820,000
8	FY2029 Tier 1 Energy (akW)	85,000	85,000	90,000	95,000	90,000	85,000	80,000	80,000	75,000	85,000	90,000	95,000
9	FY2030 Tier 1 Energy (akW)	89,250	89,250	94,500	99,750	94,500	89,250	84,000	84,000	78,750	89,250	94,500	99,750
10													
11	FY2029 Greater of:												
12	FY2029 Elected Shaping Amount (kW)	15,000	15,000	22,500	31,667	10,000	4,474	-	-	-	4,474	22,500	10,556
13	FY2029 Eligible Shaping Amount Assuming 10% (kW)	8,500	8,500	9,000	9,500	9,000	8,500	8,000	8,000	7,500	8,500	9,000	9,500
14	FY2029 RICc DemandBD Value (kW)	15,000	15,000	22,500	31,667	10,000	8,500	8,000	8,000	7,500	8,500	22,500	10,556
15													
16	FY2030 Greater of:												
17	BP-29 FY2030 Elected Shaping Amount (kW)	15,750	15,750	23,625	33,250	10,500	4,697	-	-	-	4,697	23,625	11,083
18	FY2030 Eligible Shaping Amount Assuming 10% (kW)	8,925	8,925	9,450	9,975	9,450	8,925	8,400	8,400	7,875	8,925	9,450	9,975
19	FY2030 RICc DemandBD Value (kW)	15,750	15,750	23,625	33,250	10,500	8,925	8,400	8,400	7,875	8,925	23,625	11,083
20													
21	DemandRate minus ECC (row 4 minus row 5) ($/kW/mo)	8.72	6.81	8.21	7.51	7.83	5.04	3.85	1.48	2.6	8.79	9.27	10.43
22	FY2029 RICc Numerator ($)	$ 130,800	$ 102,150	$ 184,725	$ 237,817	$ 78,300	$ 42,840	$ 30,800	$ 11,840	$ 19,500	$ 74,715	$ 208,575	$ 110,094
23	FY2030 RICc Numerator ($)	$ 137,340	$ 107,258	$ 193,961	$ 249,708	$ 82,215	$ 44,982	$ 32,340	$ 12,432	$ 20,475	$ 78,451	$ 219,004	$ 115,599
24	Sum RICc Numerator ($)	$ 2,525,920											
25	Sum RICc Denominator (sum row 6 and row 7) (kWh)	1,548,816,000											
26	Customer RICc (mills/kWh)	**1.63**											

* As stated in Section 4.5.1, as an alternative to the above example calcuation, a Block or Slice Product customer can also elect, at CHWM Contract signing, to have its RICc calculated using FY2029 Peak Net Requirement data and its FY2029 weather-normalized loads as established through the BP-29 7(i) Process.

Bonneville Power Administration
DOE/BP 5416 • February 2025