UNITED STATES COURT OF APPEALS
FOR THE NINTH CIRCUIT

Form 3. Petition for Review of Order of a Federal Agency, Board, Commission, or Officer

Name of Federal Agency, Board, Commission, or Officer:

The Bonneville Power Administration

Date of judgment or order you are challenging: 05/09/2025

Fee paid for petition? ◉ Yes ○ No

List all Petitioners *(List **each** party filing the petition. Do not use "et al." or other abbreviations.)*

NW Energy Coalition, Idaho Conservation League, Montana Environmental Information Center, Oregon Citizens' Utility Board, and Sierra Club

For immigration cases:

Alien Number(s):

Is petitioner(s) detained? ○ Yes ○ No

Has petitioner(s) moved the BIA to reopen? ○ Yes ○ No

Has petitioner(s) applied to the district director for an adjustment of status? ○ Yes ○ No

Have you filed a previous petition for review from this agency? ◉ Yes ○ No

If Yes, what is the prior 9th Circuit case number? 20-73761

Your mailing address:

810 Third Avenue

Suite 610

City: Seattle State: WA Zip Code: 98104

Prisoner Inmate or A Number (if applicable):

Signature s/ Jaimini Parekh **Date** Jul 10, 2025

Complete and file with the attached representation statement and the order being challenged. See, e.g., Circuit Rule 15-4.

Feedback or questions about this form? Email us at forms@ca9.uscourts.gov

Representation Statement for Petition for Review

Petitioner(s) *(List **each** party filing the petition, do not use "et al." or other abbreviations.)*

Name(s) of party/parties:

NW Energy Coalition, Idaho Conservation League, Montana Environmental Information Center, Oregon Citizens' Utility Board, and Sierra Club

Name(s) of counsel (if any):

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Is counsel registered for Electronic Filing in the 9th Circuit? ◉ Yes ○ No

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Respondent(s) *(List only the names of parties and counsel (if known) who will oppose you in the petition. List separately represented parties separately.)*

Name(s) of party/parties:

The Bonneville Power Administration

Name(s) of counsel (if any known):

Address:

Telephone number(s):

Email(s):

To list additional parties and/or counsel, attach additional pages as necessary.

Feedback or questions about this form? Email us at forms@ca9.uscourts.gov

No. ___________

UNITED STATES COURT OF APPEALS
FOR THE NINTH CIRCUIT

NW ENERGY COALITION, IDAHO CONSERVATION LEAGUE,
MONTANA ENVIRONMENTAL INFORMATION CENTER,
OREGON CITIZENS' UTILITY BOARD, and SIERRA CLUB,

Petitioners,

v.

THE BONNEVILLE POWER ADMINISTRATION,

Respondent.

PETITION FOR REVIEW
UNDER THE NORTHWEST POWER PLANNING AND CONSERVATION ACT FOR REVIEW OF THE BONNEVILLE POWER ADMINISTRATION'S MAY 9, 2025, DAY-AHEAD MARKET POLICY AND DAY-AHEAD MARKET RECORD OF DECISION

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NW Energy Coalition, Idaho Conservation League, Montana Environmental Information Center, Oregon Citizens' Utility Board, and Sierra Club (collectively "Petitioners") hereby petition, pursuant to Fed. R. App. P. 15(a), Circuit Rule 15-3, 5 U.S.C. § 702, and 16 U.S.C. §§ 839–839h, for review of the Bonneville Power Administration's ("Bonneville") final Day-Ahead Market Policy (the "Day-Ahead Policy") and the "Day-Ahead Market Policy Record of Decision" (the "Day-Ahead ROD"), both dated May 9, 2025. A copy of the Day-Ahead Policy is attached to this petition as Exhibit A. A copy of the Day-Ahead ROD is attached to this petition as Exhibit B.[1]

Bonneville's Day-Ahead ROD and Policy do not comply with the requirements of the Pacific Northwest Electric Power Planning and Conservation Act ("Northwest Power Act"), 16 U.S.C. §§ 839–839h, the National Environmental Policy Act ("NEPA"), 42 U.S.C. §§ 4321 *et seq.*, or the Administrative Procedure Act ("APA"), 5 U.S.C. §§ 551 *et seq.*

JURISDICTION AND VENUE

1. Petitioners seek judicial review of the Day-Ahead Policy and ROD, which are a final agency action as defined by the APA and the Northwest Power Act, respectively. 5 U.S.C. § 704; 16 U.S.C. § 839f(e). This Court has

[1] In accordance with Ninth Circuit Rule 15-3.1, Petitioners are unaware of any other Petition for Review of the same order or action.

jurisdiction under 16 U.S.C. § 839f(e)(5), which provides "the United States court of appeals" with exclusive jurisdiction over "[s]uits to challenge . . . any . . . final actions and decisions taken pursuant to this chapter by [Bonneville]." Similarly, venue is properly vested in this Court as the actions giving rise to the claims occurred in this Circuit. 16 U.S.C. § 839f(e)(5).

PARTIES

2. The Petitioners are the NW Energy Coalition, Idaho Conservation League, Montana Environmental Information Center, Oregon Citizens' Utility Board, and Sierra Club. Each of the Petitioners is a non-profit organization with offices or staff located in the area served by Bonneville and whose members have legally protectable interests that are adversely affected by Bonneville's decision in its Day-Ahead ROD and Policy.

3. The NW Energy Coalition (NWEC) is an alliance of approximately 100 environmental, civic, human service organizations, utilities, and businesses from Oregon, Washington, Idaho, Montana, Alaska, and British Columbia seeking to advance clean, equitable, and affordable energy policies. As part of its mission, NWEC promotes energy conservation and renewable energy resources, consumer and low-income protection, and fish and wildlife restoration in the Northwest. NWEC's headquarters are located in Seattle, Washington.

4. The Idaho Conservation League (ICL) is a nonprofit corporation organized and existing under the laws of the state of Idaho and dedicated to ensuring protections for clean water and air, healthy families, and Idaho's unique way of life. As part of its mission, ICL advocates for actions that reduce the impact of electrical generation and transmission on natural resources and ecosystems, including, but not limited to, wild salmon and steelhead in the Columbia and Snake River Basins, while at the same time providing reliable and affordable power to all Idaho citizens.

5. The Montana Environmental Information Center (MEIC) is a non-partisan, non-profit environmental advocacy organization dedicated to ensuring clean air and water for Montana's present and future generations. Founded in 1973 by Montanans concerned with protecting and restoring Montana's natural environment. MEIC has approximately 5,000 members and supporters. MEIC seeks to promote the development of clean energy and energy efficiency, reduce energy costs to its members, insulate consumers from fuel price risk, and maximize the use of existing transmission resources to protect Montana's natural environment from harm.

6. The Oregon Citizens' Utility Board ("Oregon CUB") is an independent, statewide 501(c)(3) organization with over 40 years of experience advocating for consumers' utility interests. Oregon CUB's mission is to advocate

for affordable, accessible, reliable, and clean utilities for people in Oregon. Its core activities are to conduct economic and legal analysis of utility systems; engage with community organizations, utilities, and policymakers to address current and emerging utility issues; and advocate for fair and equitable policies that prioritize the needs of residential customers and communities.

7. The Sierra Club is a national environmental organization founded in 1892 and devoted to the study and protection of the earth's scenic and ecological resources. As part of its mission to protect these resources, the Sierra Club advocates for clean, renewable, and affordable energy from the electricity grid that is both carbon free and just. Sierra Club has 60 chapters in the United States and Canada, including chapters in Washington, Oregon, and Idaho, and a principal place of business in San Francisco, California.

8. The Respondent in this petition is the Bonneville Power Administration, a federal power-marketing agency within the U.S. Department of Energy (USDOE) that sells electricity generated by a series of federal hydroelectric dams and other resources in the Columbia River Basin and that owns an extensive electricity transmission grid in the Northwest and beyond.

BACKGROUND AND STANDING

9. Petitioners' organizations, as well as their individual members, are harmed by Bonneville's Day-Ahead ROD and Policy. The Day-Ahead ROD and

Policy set forth a final decision by Bonneville to move forward with participating in the Southwest Power Pool (SPP)'s Markets+ day-ahead electricity market ("Markets+").

10. A day-ahead electricity market is a formalized mechanism for matching electricity demand with supply on a day-ahead basis through the purchase and sale of electricity across an area larger than an individual utility's service area. This kind of organized market across utilities and geography can create opportunities for greater efficiency and lower costs for market participants like Bonneville in the purchase, sale and delivery of electricity to businesses and individuals within the day-ahead market footprint. A larger day-ahead market footprint with a more connected geography and a greater diversity of electricity generation resources (wind, solar, battery, hydropower, natural gas, and so on) will result in lower costs and improve reliability for customers of utilities within that market. This is because a larger, better connected, more diverse market provides more opportunity for the purchase and sale of electricity in ways that increase efficiency in both power generation and transmission. Increased efficiency, in turn, not only reduces costs to electricity users but it also reduces the need to build additional generating resources and transmission and, thereby, reduces impacts to natural resources and the environment.

11. Bonneville's Day-Ahead ROD and Policy set forth Bonneville's basis for choosing between two day-ahead market options, Markets+—which Bonneville has chosen—or the Extended Day-Ahead Market ("EDAM") developed by the California Independent System Operator ("CAISO"). The CAISO EDAM has a larger footprint as well as a greater diversity and extent of electrical generation resources. Further, Bonneville is better connected to the transmission grid of the CAISO EDAM because the grid is more geographically contiguous, its market participants include more of Bonneville's historic trading partners and, consequently, the transmission system is better developed than is the case for Markets+.

12. Bonneville's Day-Ahead ROD and Policy also considered a no-action alternative, wherein it modeled the costs and benefits of remaining in the Western Energy Imbalance Market (or WEIM) also operated by CAISO and in which Bonneville is already a participant, without joining any day-ahead market.[2] The CAISO WEIM is itself an organized electricity market but one that provides

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[2] In its Policy and ROD, Bonneville evaluates two scenarios in its no-action alternative. The first scenario assumes that no regional power and transmission providers join a day-ahead market. Bonneville Day-Ahead Policy at 21–22. Bonneville acknowledged this scenario was unlikely to occur. It therefore also evaluated a scenario where some regional power and transmission providers join a day-ahead market, but Bonneville does not and instead remains in the WEIM. *See* Bonneville Day-Ahead Policy at 30–31. The Policy and ROD compares the costs and benefits of joining a day-ahead market to this no-action alternative.

participants the opportunity to match power generation with demand through sale and purchase of electricity on a much shorter-term basis (an hour or less) than a day-ahead market. In order to move ahead with participation in Markets+, as Bonneville's Day-Ahead ROD and Policy indicate it plans to do, Bonneville will be required to withdraw from the WEIM and lose the benefits of participation in it.

13. Bonneville's Day-Ahead ROD and Policy are a final decision, wherein Bonneville considered the alternatives of Markets+, EDAM or remaining in the WEIM and not joining a day-ahead market. It is the culmination of a years-long decision-making process in which Bonneville repeatedly solicited input from regional stakeholders and the interested public on what market it should choose, and whether to join a day-ahead market at all. In the ROD and Policy, Bonneville made a final determination that it will "pursue participation in a day-ahead market and specifically pursue participation in Markets+." Day-Ahead Policy at 2.

14. Bonneville's choice of Markets+ over EDAM, or the no-action alternative, will have serious and adverse consequences for Petitioners' organizations as well as businesses and individuals who receive their electricity from utilities that acquire some or all of their power from Bonneville. These adverse effects include, but are not limited to, paying higher power costs for electricity if Bonneville participates in Markets+ as opposed to EDAM.

15. Bonneville's choice of Markets+ will also have further significant and harmful impacts on Petitioners and their members. These impacts include, but are not limited to, inefficient grid operations because of very complex "seams"[3] that inhibit efficient transmission of electricity between participants in Markets+ and partners outside Markets+. These seams, in turn, affect the costs of power and can affect the reliability of the transmission system by making it more difficult and expensive to transmit electricity across seams, and making it more complicated for electricity providers in the Northwest to trade with providers both within and outside the smaller and more fractured footprint of Markets+. The seams created within Bonneville's service area by two markets would also raise transaction and coordination costs for all utilities in the region and add to already steep pressure towards increased rates for all Northwest electric customers. Electricity transmission in the Northwest is already both complex and constrained, and Bonneville's decision will likely result in greater grid inefficiencies affecting regional electricity reliability and power costs.

[3] "Seams" are points at which electricity must be transmitted across boundaries between different utilities and balancing areas and require complex agreements that affect the costs and efficiency of power delivery to meet demand. Bonneville's choice of Markets+ for a day-ahead market creates especially challenging and compound seams as compared to a choice of EDAM or remaining in the WEIM.

16. Moreover, Bonneville's day-ahead market decision will likely require regional electricity providers to construct additional power generation facilities and/or increase operation of existing facilities, including natural gas, and coal plants, as a consequence of Bonneville's participation in the smaller and less efficient, less diverse Markets+. Increased reliance on generating resources powered by fossil fuels will have adverse effects on air and water quality as well as individuals living near gas and coal generation facilities. BPA did not rationally explain how joining the smaller, non-contiguous Markets+ footprint will enable it to meet its duty to promote an adequate, efficient, economical, and reliable power supply for the region that also gives priority to clean, renewable resources.

17. Bonneville's choice of Markets+ will also likely increase the risk of harmful power blackouts during periods of high or extreme electricity demand because of the many and complex seams that power must be transferred across in Markets+ as compared to EDAM or the no-action alternative, and this increased risk of blackouts will harm petitioners and their members.

18. In addition, Bonneville's choice of Markets+ will likely lead to use of available flexibility in the operation of the federal hydroelectric dams from which Bonneville markets power in ways that are harmful to salmon and other fish species in the Columbia and Snake Rivers, especially during periods of peak power demand and low water flow, or during periods where Bonneville can make

additional money by maximizing power generation within allowable operational limits but to the disadvantage of salmon and other species. These impacts are all a reasonably foreseeable consequence of Bonneville's decision to choose participation in Markets+ over EDAM, or the no-action alternative.

19. Further, as a result of Bonneville's choice of Markets+, each of the petitioner organizations will be compelled to devote increased organizational resources to monitoring, participating in and advocating for implementation of the many aspects of Bonneville's choice of Markets+ in order to reduce the potential for increased electric power costs, inefficient use of the existing transmission grid that may also result in the construction of unnecessary transmission capacity, and inefficient and harmful use of existing electricity generating resources—including but not limited to hydropower dams, natural gas and coal-fired power plants, and development of new generation resources that could have been avoided.

BONNEVILLE'S DAY-AHEAD ROD AND DAY-AHEAD POLICY VIOLATE THE NORTHWEST POWER ACT, NEPA AND THE APA.

20. On May 9, 2025, Bonneville adopted its Day-Ahead ROD and Policy for which Petitioners now seek judicial review pursuant to Northwest Power Act § 839f(e). Bonneville's Day-Ahead ROD and Policy are final agency actions that

set forth a critical and final decision about which of three alternative courses of market participation to pursue.[4]

21. As the Day-Ahead ROD and Policy make clear, through an extensive public process and after comparing market alternatives, Bonneville chose to move forward with participation in Markets+. Any future proceedings by Bonneville will not revisit the question of whether to join a day-ahead market, or if so, which day-ahead market to participate in. Rather future proceedings will be limited to actions related to implementation of the decision in the Day-Ahead ROD and Policy. As Bonneville says in its Day-Ahead ROD, the ROD "sets the direction for future proceedings," Day-Ahead ROD at 131, and in accordance with the ROD and Policy, Bonneville will "pursue participation in a day-ahead market and specifically pursue participation in Markets+[.]" Day-Ahead Policy at 2. The ROD and Policy thus have legally binding consequences for future contractual agreements, tariffs, and rate proceedings as those obligations are negotiated or renegotiated to accommodate Bonneville's participation in Markets+.

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[4] Petitioners offer this overview and summary of their claims under the Northwest Power Act, NEPA and the APA against Bonneville's Day-Ahead ROD and Policy without waiving any argument, issue or claim that may arise in the course of reviewing the administrative record, preparing and briefing this petition.

A. Bonneville's Day-Ahead ROD and Policy Violate the Northwest Power Act.

22. Bonneville has authority to join a day-ahead market pursuant to its power to contract, 16 U.S.C. § 832a(f), and its authority to investigate and join an interregional regional exchange of electric power, *id.* § 839d(l). In fact, the Northwest Power Act directs Bonneville to investigate opportunities for "mutually beneficial interregional exchanges of electric power that reduce the need for additional generation or generating capacity in the Pacific Northwest and the regions with which such exchanges may occur." 16 U.S.C. § 839d(l)(2). Consistent with the purposes of the Northwest Power Act, in considering whether to join a day-ahead market, Bonneville is also required to make a decision that would "assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply[.]" 16 U.S.C. § 839(2).

23. The Northwest Power Act requires Bonneville to prioritize the acquisition of resources that are cost-effective, consider impacts to the regional power system, pursue actions that reduce the need for additional generation or generating capacity in the Pacific Northwest, and promote acquisition of renewable power. The Northwest Power Act provides that Bonneville is authorized to acquire "mutually beneficial interregional exchanges of electric power" provided that its

decision is consistent with the Northwest Power Plan. 16 U.S.C. § 839d(l)(2)–(3).[5] The 2021 Northwest Power Plan, which is currently in effect, recognizes the importance and value that joining a west-wide day-ahead market could provide, and states that Bonneville should consider and pursue "[t]he least-cost option to maintain an adequate, cost-effective regional system[.]" 2021 Northwest Power Plan at 107. [6]

24. Similarly, the Northwest Power Act itself requires giving primary priority to "cost-effective" resources, and then prioritizing resource acquisition "first, to conservation; second, to renewable resources; third, to generating resources utilizing waste heat or generating resources of high fuel conversion efficiency; and fourth, to all other resources." 16 U.S.C. § 839b(e)(1). The Northwest Power Act also requires consideration of "(A) environmental quality, (B) compatibility with the existing regional power system, (C) protection, mitigation, and enhancement of fish and wildlife and related spawning grounds and habitat" when planning for the development or acquisition of resources. 16 U.S.C. § 839b(e)(2).

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[5] The Northwest Power Plan is developed by the Northwest Power Planning Council, a four-state entity created by the Northwest Power Act and authorized to prepare both power supply and fish and wildlife protection plans to guide power planning and development in the four-state region. *See* 16 U.S.C. § 839b.
[6] Northwest Power Planning Council, *2021 Northwest Power Plan*, at 107, https://www.nwcouncil.org/2021-northwest-power-plan/.

25. Here, however, Bonneville has dismissed the substantial cost savings that the available analyses indicate it would achieve if it had decided to move ahead with participation in the CAISO EDAM. Instead, Bonneville chose an alternative that would increase power and transmission costs for its customers and everyone in the region it serves, reduce system reliability, create numerous difficult and costly seams across the Western grid, and erode Bonneville's access to its current trading partners. Bonneville also dismissed impacts to the regional power system, including the substantial impacts that joining Markets+ would have on regional power costs and reliability, and the likelihood that a decision to join Markets+ would promote increased reliance on coal and other fossil fuel generation throughout the Western Interconnection.

26. In doing so, BPA failed to meet its public obligations to maintain a reliable, affordable energy system that promotes renewable energy development while protecting fish, wildlife and cultural resources as mandated by the Northwest Power Act. Finally, as noted below in discussing Bonneville's failure to comply with NEPA, it has failed to consider or disclose the impacts to environmental quality, including impacts to fish and wildlife, of its decision to move ahead with participation in Markets+.

27. Further, Bonneville preferentially weighted its analysis in a manner that arbitrarily favored Markets+ by, among other steps, dismissing the viability of

participation in EDAM because of Bonneville's variously stated policy concerns about EDAM governance. *See*, *e.g.*, Day-Ahead Policy at 57. By elevating these policy concerns about market governance above the factors the Northwest Power Act and the Northwest Power Plan require Bonneville to address Bonneville failed to articulate a rational basis for its action in light of its legal obligations.

28. For reasons, including but not limited to those summarized above, Bonneville violated the Northwest Power Act when it discounted factors the agency is statutorily required to consider, and arbitrarily preferred Markets+ in its consideration of which day-ahead market to move forward with participation in.

B. Bonneville's Day-Ahead ROD and Policy Violate NEPA.

29. Bonneville's Day-Ahead ROD and Policy are a final agency action and a major federal action that is likely to have significant and adverse environmental effects. These effects include, but are not limited to, the kinds of effects described in paragraphs 9 to 19 above. Bonneville, however, has failed to prepare an Environmental Impact Statement—or any other form of analysis—pursuant to NEPA for its decision to move forward with participation in Markets+, rather than moving forward with participation in EDAM or remaining in the WEIM without joining a day-ahead market. Instead, without analysis, Bonneville states that its Day-Ahead ROD and Policy are "not expected to result in *any* environmental impacts requiring analysis . . . [because the Day-Ahead ROD and

Policy] do[] not *obligate* Bonneville to join Markets+; a final decision on whether to join would be made by Bonneville at a later date. Appropriate additional NEPA analysis and documentation would be conducted prior to making that final agency decision." Day-Ahead ROD at 149 (emphasis added). While it may be true that Bonneville's Day-Ahead Policy and ROD do not "*obligate* Bonneville to join Markets+," it is also true that the ROD and Policy set forth Bonneville's final decision to move ahead with implementation of participation in Markets+.

30. Bonneville's rationale for avoiding any NEPA analysis for its Day-Ahead ROD and Policy is arbitrary and contrary to law. First, there will be significant—and different—environmental consequences that will result from Bonneville's decision to move forward with participation in Markets+ instead of EDAM or staying in the WEIM. Moreover, there is no indication that Bonneville's choice among these alternatives will be reexamined in any later decision about the details of implementing Bonneville's participation in Markest+.

31. Second, Bonneville cannot rationally truncate its consideration of the significant environmental effects of its choice among day-ahead market alternatives by mischaracterizing the effects of its Day-Ahead ROD and Policy as purely "administrative and procedural." Day-Ahead ROD at 149. The decision Bonneville made in its Day-Ahead ROD and Policy is to move ahead with participation in Markets+. And as Bonneville's extensive analysis of this choice in

both its Day-Ahead Policy and ROD plainly show, this decision will have long-term and significant economic effects for Bonneville and the utilities, businesses and individuals it serves. While Bonneville made a considerable effort to evaluate these future economic effects, it made no effort to evaluate the future environmental effects of the choices it faced. Bonneville cannot properly choose to evaluate only some of the likely future impacts of its decision to move ahead with participation in Markets+ (the economic effects) while relying on a mischaracterization of its action to avoid analysis of other future effects (the environmental consequences), especially where, as here, the failure to evaluate these environmental effects had been pointed out to the agency, and the means to make reasonable forecasts about these effects are available.

32. In fact, Bonneville has already made an irreversible commitment of its resources to participation in Markets+ without complying with NEPA. Specifically, Bonneville has provided SPP with the equivalent of a letter of credit for up to $40 million to enable SPP to secure a bank loan that is necessary to develop and implement Markets+. Under Bonneville's market development funding agreement with SPP, this financial commitment is irreversible: if Bonneville withdraws from participation in Markets+, up to the full amount of the $40 million backed by its "letter of assurances" will be immediately due and payable. It is immaterial to the irreversible nature of this financial commitment

that Bonneville would not have to actually pay $40 million in cash to SPP so long as it does not withdraw from the Markets+ funding agreement and eventually joins and participates in Markets+. In fact, those conditions confirm that Bonneville's financial commitment to Markets+ is irreversible under NEPA, its regulations and the relevant case law.

33. Finally, to the extent Bonneville seeks to rely on the interim final NEPA regulations recently published by USDOE to justify its failure to consider the environmental consequences of the challenge action, *see* Revision of National Environmental Policy Act Implementing Procedures, 90 Fed. Reg. 29676-29710, these regulations are illegal as applied to Bonneville's Day-Ahead ROD and Policy. The USDOE cannot take an action that will likely significantly affect the quality of the human environment, without considering and disclosing those affects. *See* 42 U.S.C. § 4332(c).

C. Bonneville's Day-Ahead ROD and Policy Violate the APA.

32. For reasons, including but not limited to those summarized above, Bonneville's Day-Ahead ROD and Policy are arbitrary, capricious and contrary to law in violation of the APA. 5 U.S.C. 706(a)(2).

PRAYER FOR RELIEF

Petitioners respectfully request that this Court:

A. Adjudge and declare that Bonneville's Day-Ahead ROD and Policy violate NEPA because they are a major federal action that may affect the human environment but Bonneville has failed to prepare an environmental impact statement or any other NEPA analysis for this action.

B. Adjudge and declare that Bonneville's Day-Ahead ROD and Policy violate the Northwest Power Act because the Policy and ROD fails to comport with Bonneville's obligations under the Act.

C. Adjudge and declare that the Bonneville Day-Ahead ROD and Policy violate the APA because they are arbitrary, capricious and otherwise not in accordance with law.

D. Vacate Bonneville's Day-Ahead ROD and Policy, direct Bonneville to rescind its irreversible and illegal financial commitment to Markets+, and require Bonneville to comply with NEPA, the Northwest Power Act, the APA; and,

E. Grant Petitioners such other and further relief, including equitable relief and attorneys' fees and other expenses as may be authorized by law and as Petitioners may from time-to-time request.

Respectfully submitted this 10th day of July, 2025.

s/ Jaimini Parekh
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EXHIBIT A

Bonneville's Day-Ahead Market Policy

May 9, 2025

Bonneville Power Administration

Day-Ahead Market Policy

May 9, 2025

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1. Executive Summary

The Bonneville Power Administration's Day-Ahead Market Policy (Policy) contains the policy direction of the Administrator of the Bonneville Power Administration based on the extensive stakeholder process analyzing Bonneville's potential day-ahead market participation in the California Independent System Operator's (CAISO) Extended Day-Ahead Market (EDAM) or the Southwest Power Pool's (SPP) Markets+. Bonneville conducted its stakeholder process from July 2023 through May 2025. During this time, Bonneville was, and continues to be, an active participant in both CAISO and SPP's stakeholder processes. The purpose of the Day-Ahead Market Policy is to transparently inform stakeholders about the scope of subsequent actions towards market participation.

On March 6, 2025, Bonneville issued its Day-Ahead Market Draft Policy, which proposed Bonneville should participate in a day-ahead market and pursue participation in Markets+ due to its superior market design, independent governance structure, and inclusive stakeholder process. This was followed by a 30-day formal comment period, which resulted in 1,614 comments. This Policy provides background information, addresses issues raised during the comment period and memorializes Bonneville's final direction and provides initial guidance on next steps.

After careful consideration of public input on Bonneville's evaluation principles and key considerations, governance and stakeholder processes, resource adequacy and resource sufficiency, price formation and market power mitigation, transmission and congestion rent and greenhouse gas accounting, Bonneville will adopt the recommendations in the draft policy and pursue participation in a day-ahead market and specifically pursue participation in Markets+.

Bonneville will now shift its focus to joining Markets+ by initiating a formal process to implement Markets+ participation. Bonneville will address customers' and stakeholders' impacts in future proceedings such as its rate case and tariff terms and conditions proceedings, and if Bonneville ultimately joins the market as a participant, it will address impacts in these forums as well as transmission business practice updates and a Provider of Choice power sales contract day-ahead market amendment process. Bonneville will leverage the lessons learned from its Western Energy Imbalance Market (WEIM) decision process, ultimately making a decision to go-live after reevaluating it through the implementation process, including any changes to the structure of Markets+ or underlying facts since the earlier phase of Markets+ final policy.

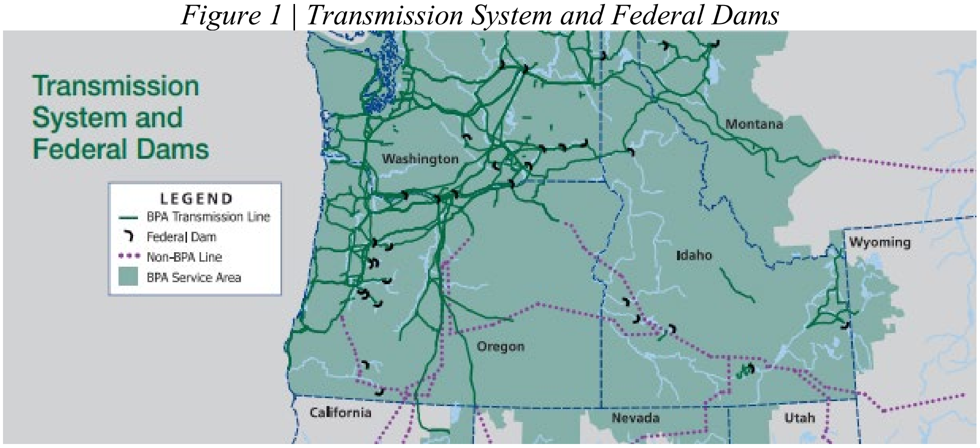
2. Introduction

In July 2023, Bonneville began to engage the region in a public process to evaluate its potential participation in a day-ahead market. As one of the largest wholesale power and transmission providers in the Western Interconnection, Bonneville's decision regarding day-ahead market participation will play a critical role in the energy and capacity market landscape for the region.

2.1. Description of the Bonneville System

Bonneville is a federal power marketing administration under the United States (U.S.) Department of Energy, is self-funding, and covers its costs by selling its products and services. Bonneville makes power sales and provides transmission service within its statutorily defined service territory in the Pacific Northwest,[1] including Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah, and Wyoming. Bonneville markets about 32% of the wholesale electric power generated in the Pacific Northwest[2] from 31 federal hydroelectric dams, one non-federal nuclear plant, and several smaller non-federal generating resources.[3] See Figure 1 for a visual of hydroelectric resources. Bonneville also operates and maintains more than 15,000 circuit miles of high-voltage transmission in its service territory, which is used to deliver power to its customers and transmit power for third-party transmission customers.

Figure 1 | Transmission System and Federal Dams



Bonneville's statutory mission is threefold: (1) to provide an adequate, efficient, economical, and reliable power supply to its firm power customers in the Pacific Northwest; (2) to provide a transmission system that is adequate to the task of integrating and transmitting power from federal and non-federal resources, providing service to Bonneville's customers, providing interregional interconnections, and maintaining electrical reliability and stability; and (3) to mitigate the impacts on fish and wildlife from the federally owned hydroelectric projects from which Bonneville markets power.

[1] In this Policy, the "Pacific Northwest" or "region" has the meaning set forth in the Northwest Power Act, 16 U.S.C. § 839a(14).
[2] Bonneville Power Administration, BPA Facts (Sept. 2024), *available at* https://www.bpa.gov/about/newsroom/fact-sheets.
[3] *Id.*; *see also* Bonneville Power Administration, 2024 Pacific Northwest Loads and Resources Study (Aug. 2024) ("The White Book"), *available at* https://www.bpa.gov/-/media/Aep/power/white-book/2024-white-book.pdf.

2.2. Development of Day-Ahead Markets in the West

As background, the Bulk Electric System in the U.S. is managed in six different regions.[4] The Western Interconnection is the largest region encompassing 38 Balancing Authority Areas (BAAs)[5] that are individually responsible for ensuring the reliable operation of the electric grid.[6] The regulatory Regional Entity approved by the Federal Energy Regulatory Commission (FERC) for the Western Interconnection is the Western Electricity Coordinating Council (WECC). The North American Electric Reliability Corporation (NERC) delegated some of its authority to create, monitor, and enforce reliability standards to WECC through a Delegation Agreement.[7] WECC promotes bulk power system reliability and security.

Historically, entities within the Western Interconnection have managed and balanced electricity supply and demand through bilateral transactions across forward contracts of varying duration, day-ahead transactions, and real-time transactions. The CAISO BAA is an exception in its role as an Independent System Operator (ISO).[8] Outside of the Western Interconnection, most regions have transitioned from a bilateral framework into ISOs or Regional Transmission Organizations (RTOs).[9] RTOs and ISOs manage about 60% of the U.S. electric power supply[10] and expand market activities through the consolidation of many BAAs into one BAA. They each maintain a single Open Access Transmission Tariff with standardized terms and conditions for transmission service and centralized transmission planning.

One component of RTOs and ISOs is the inclusion of a centrally organized market. A centrally organized market is administered by a market operator, which is a clearinghouse for bids and offers from market participants. Market participants continue to transact bilaterally on a forward time horizon but allow the market to dispatch generation and serve load across the day-ahead and real-time time horizons.[11] All centralized markets use Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) accompanied by a nodal network model with Locational Marginal Pricing

[4] For more information, see Federal Energy Regulatory Commission (FERC), Electric Power Markets, *available at* https://www.ferc.gov/electric-power-markets.

[5] A BAA is defined as "The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area." North American Electric Reliability Corp., Glossary of Terms used in NERC Reliability Standards at 5 (Jan. 7, 2025), *available at* https://www.nerc.com/pa/stand/glossary%20of%20terms/glossary_of_terms.pdf. In turn, a Balancing Authority is defined as "The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time." *Id.*

[6] BAAs are responsible for meeting North American Electric Reliability Corporation (NERC) reliability compliance standards (*see NERC*, *available at* https://www.nerc.com) and Western Electricity Coordinating Council (WECC) reliability compliance standards (*see* WECC, *available at* https://www.wecc.org).

[7] WECC, About WECC, *available at* https://www.wecc.org/about/about-wecc.

[8] FERC Order No. 888, 75 FERC ¶ 61,080, promoted the concept of ISO formation based on an earlier "power pool" concept. Several groups of transmission owners then formed ISOs, some from existing power pools Along with facilitating open access to transmission, ISOs operate the transmission system independently, and foster competition for electricity generation among wholesale market participants.

[9] In Order No. 2000, 89 FERC ¶ 61,285, FERC encouraged utilities to join regional transmission organizations (RTOs), which, like an ISO, would operate the transmission systems and develop innovative procedures to manage transmission equitably.

[10] U.S. Energy Information Administration, *About 60% of U.S. Electric Power Supply is Managed by RTOs* (Apr. 4, 2011), *available at* https://www.eia.gov/todayinenergy/detail.php?id=790#:~:text=Source:%20ISO/RTO%20Council,power%20marketers%20and%20energy%20traders.

[11] An RTO is an entity that is independent from all generation and power marketing interests and has exclusive responsibility for grid operations, short-term reliability, and transmission service within the region. Enerdynamics, Energy Knowledge Database, FERC Order 2000, *available at* https://energyknowledgebase.com/topics/ferc-order-2000.asp.

(LMP)[12] to create an "economic dispatch."[13] Section 1234 of the Energy Policy Act of 2005 defines "economic dispatch" as "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[14]

CAISO operated an organized day-ahead and real-time market solely within its BAA footprint comprising most of California until 2014. In 2014, CAISO expanded its real-time market by offering the Western Energy Imbalance Market (WEIM) as an option for other BAAs in the Western Interconnection to join.[15] Voluntarily on an hourly basis, participants offer resources for within-hour dispatch by the market to manage the difference in energy for load and resources between what was scheduled ahead of time and what materializes in real-time. The market operator uses SCED to meet the within-hour real-time energy imbalances with the most cost-effective generation offered to the market. Unit commitment is generally performed by the market participants, not by CAISO in this real-time market. WEIM balances fluctuations in supply and demand by dispatching lower cost resources and it manages congestion on transmission lines to maintain grid reliability and to support integrating new resources.[16]

WEIM now includes 21 BAA participants operating the majority of the Western Interconnection.[17] CAISO's overarching market governance is entrusted to the CAISO Board of Governors. The Board has delegated certain authority for the WEIM to the Western Energy Markets (WEM) Governing Body, subject to the Board's oversight, in a model referred to as Joint Authority.[18] The CAISO Board of Governors is appointed by the Governor of California with the consent of the California State Senate.

In 2021, SPP launched a second imbalance market offering in the Western Interconnection, the Western Energy Imbalance Service market (WEIS). The WEIS has 16 participants. SPP's independent board of directors provides ultimate oversight of the administration of the WEIS market. In its role as the market operator, SPP performs analysis to ensure each balancing authority (BA) and market participant in each BA's boundaries have enough generation in their operating plan to satisfy the load and obligations for that

[12] *See* SPP Markets+ Tariff, Attach. A § 3.2, *available at* https://www.spp.org/Documents/71376/Markets%20Plus%20Tariff%20amended%2020240405_filed%20version%202.pdf ("The LMP at a Pnode is the cost of delivering an incremental MW of Energy at that specific Pnode, while satisfying all operational constraints where such cost will include applicable Demand Curve prices if the incremental MW of Energy would result in a corresponding increase in shortage conditions. The LMP at any Pnode is the sum of three components: the marginal costs of Energy (the MEC), the marginal cost of losses (the MLC), and the marginal cost of congestion (the MCC)"). LMPs are the commonly accepted means for settling resources and loads in all centrally organized markets in the U.S. For more thorough details on the history and development of LMPs and the various considerations of how they are used within organized markets, see Harvey Scott & William Hogan, *Locational Marginal Prices and Electricity Markets* (2022), *available at* https://whogan.scholars.harvard.edu/sites/g/files/omnuum4216/files/whogan/files/locational_marginal_prices_and_electricity_markets_hogan_and_harvey_paper_101722.pdf.

[13] *See* FERC, Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations: A Report to Congress Regarding the Recommendations of Regional Joint Boards for the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005 (July 31, 2006), *available at* https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.

[14] 42 U.S.C. § 16432.

[15] *See* CAISO, Western Energy Imbalance Market (WEIM) (2025), *available at* https://www.westerneim.com/Pages/About/default.aspx.

[16] *See* CAISO, How the Markets Work (2025), *available at* https://www.westerneim.com/Pages/About/HowItWorks.aspx.

[17] *See* CAISO, Western Energy Imbalance Market (WEIM) (2025). *available at* https://www.westerneim.com/Pages/About/default.aspx.

[18] *See* CAISO, Governance (2025), *available at* https://www.westerneim.com/Pages/Governance/default.aspx.

market participant and BA.[19] The WEIS accommodates a diverse set of resource types. This helps ensure the market operates as efficiently as possible and can take advantage of the capabilities of different resources.[20] As of 2022, WEIS balanced the demand for real-time energy and the power produced by more than 150 generating units in its multi-state footprint.[21]

Both CAISO and SPP have developed proposals to develop day-ahead markets that would manage a significant increase in the volume of transactions. CAISO began development of EDAM in 2019,[22] and SPP began development of Markets+ in 2022.[23,24] A day-ahead market is designed to optimize a participant's loads, resources, and transmission within the market footprint using a security constrained unit commitment and economic dispatch on a day-ahead basis with hourly granularity coupled with the underlying real-time market. In the real-time WEIM and WEIS markets, participants can submit voluntary bids for the next hour in sub-hourly (15-minute or five-minute) increments. In contrast, in a day-ahead market, participants can bid generation capacity and load for every hour in the day-ahead timeframe, which is then optimized by the unit commitments and economic dispatch accounting for constraints, including transmission availability and congestion. A day-ahead market continues to include a real-time market component, including voluntary submissions of any remaining real-time energy, much like the existing WEIM and WEIS.

Notably, CAISO and SPP employed different stakeholder participation models to develop the EDAM and Markets+ proposals. CAISO designed and authored the EDAM market offering, and Bonneville participated in stakeholder meetings, reviewed proposals, and provided written comments. CAISO ultimately determined which stakeholder suggestions to address and incorporate into the final EDAM design. Certain key issues that Bonneville raised were not fully addressed. In contrast, while SPP developed the initial conceptual framework for Markets+, stakeholder workgroups developed the Markets+ design elements to reflect the operational characteristics of the Western Interconnection. Bonneville participated in the committees, work groups, and task forces that developed Markets+ tariff language and business protocols. The collaborative design framework of Markets+ better addressed the many issues raised by Bonneville and other stakeholders.

2.3. Why is Bonneville Considering Joining a Day-Ahead Market?

Bonneville joined CAISO's WEIM in May 2022, eight years after its inception, after the market had grown into a large footprint and matured in its design elements. With FERC approval of two day-ahead market offerings, Bonneville expects day-ahead markets to gain a foothold, particularly with some states requiring utilities to transition to organized markets.[25] Based on its experience as a later entrant to the WEIM, Bonneville believes that early day-ahead market involvement will better meet its customer and stakeholder

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[19] *See* SPP, A Proposal for the Southwest Power Pool Western Energy Imbalance Service (WEIS) (2019), *available at* https://www.spp.org/documents/60104/a%20proposal%20for%20spp's%20western%20energy%20imbalance%20service%20market.pdf.

[20] *See* SPP, Western Energy Imbalance Service Market (2025), *available at* https://www.spp.org/western-services/weis/.

[21] SPP, Annual Report 2022 at 4, *available at* https://spp.org/documents/70194/2022%20annual%20report%20-%209.26.23.pdf.

[22] *See* CAISO, Initiative: Extended day-ahead market, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.

[23] *See* SPP, Markets+, *available at* https://www.spp.org/western-services/marketsplus/.

[24] SPP is also developing RTO West in the Western Interconnection, with the corresponding tariff approved by FERC on March 20th, 2025. See *Southwest Power Pool, Inc., 190 FERC ¶61,169 (2025)*. RTO West is a separate offering from Markets+ and is not co-optimized with the Markets+ footprint.

[25] FERC Office of Public Participation, Western Energy Markets Explainer (Jan. 2025), *available at* https://www.ferc.gov/OPP/western-markets-explainer.

objectives because the first years of a market greatly influence development and maturation of the market design. The following are some categories of benefits that are associated with day-ahead market participation.

Continued Access to Trading Partners via a Liquid Market

Bonneville has observed a strong interest in day-ahead market development across the West, and many entities have already indicated their intent to pursue participation in the coming years. Today, Bonneville transacts bilaterally to ensure it meets its load service and operational obligations and to maximize the value of net-secondary revenue to keep rates low for customers. As entities joined the WEIM, Bonneville and others outside of the WEIM noticed reductions in the liquidity of the hourly bilateral market. Similarly, Bonneville expects that organized day-ahead market growth may result in reduced liquidity in both the day-ahead and real-time bilateral markets.[26] The expected result is fewer options for bilateral purchases of power or fewer counterparties to sell to, which could result in operational impacts and increased financial hurdles associated with these transactions. Participation in a day-ahead market will allow Bonneville continued access to a range of trading partners, without increasing hurdles and barriers to transact, so it can continue to carry out its objectives in the day-ahead and real-time horizons.

Optimization

An organized day-ahead market brings together a variety of resources and loads and enables an optimization to dispatch those resources to serve loads at the least cost. Both buyers and sellers can achieve economic benefit. Dispatched resources are compensated at their bid or higher for the energy they offered to supply. Resources that are not dispatched are given a concrete price signal to either conserve their resource for future periods of higher demand or offer a more competitive bid if they wish to be awarded. Loads can economically bid in day-ahead to indicate a price at which they are willing to purchase energy, and all loads are ultimately served in real-time through the least-cost economic dispatch. The optimization allows for a broader and more transparent exchange of pricing information. Compared to the bilaterial world of today, where there are numerous information asymmetries, a market optimization can provide participants, including Bonneville, with access to a more transparent picture of regional operations and tradeoffs, which aids both financial transactions and operational awareness.

In addition, joining a day-ahead market will give Bonneville better access to resources and loads across a broader footprint compared to bilateral markets. This allows for more flexible resources to respond to the needs of loads across that footprint. For resources with significant ramping capabilities, such as Bonneville's hydro resources, the more granular awards and dispatches of an organized market benefit both customers and the region more broadly.

Reliability

As a BA and a Transmission Operator (TOP), Bonneville is tasked with operating the electric grid in a reliable manner. Bonneville may utilize participation in an organized day-ahead market to reliably operate the grid. The market operator has a much wider view of transactional activity and grid operation compared to that of each individual BAA. Prior to real-time, the day-ahead market operator can forecast load needs and transmission constraints (i.e., areas on the transmission grid that may end up operating at their maximum transfer capacity based on expected system conditions), and award resources in a manner that honors those constraints in the day-ahead and real-time horizons. The market operator can also redispatch generation to reliably and most economically serve load (e.g., by supplying energy from a different resource

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[26] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment (Sept. 2020), *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

that relieves a transmission constraint).[27] This ability of the market operator may reduce the likelihood and magnitude of transmission curtailments by Transmission Service Providers (TSP)/TOP.

Energy Resources

Bonneville has pledged to respond to customers' requests for integration of energy resources through the Evolving Grid initiative.[28] According to WECC's 2024 State of the Interconnection report, entities in the Western Interconnection plan to build close to 172 gigawatts (GW) of resources in the next 10 years. Addressing the changing resource mix and load shapes will be more successful through improved operation and coordination among many BAAs. An organized day-ahead market offers broader access to a larger portfolio of resources, which will enhance reliability because the market operator may dispatch resources within the broader market footprint.[29]

Timeliness

While many commenters have called for a delay in Bonneville's day-ahead market policy decision, for reasons including for additional time to comment, to allow EDAM governance to continue to develop, to conduct government-to-government consultation, and to conduct further economic analysis, Bonneville must declare a policy direction now. Strategically, Bonneville's timeline allows better coordination with other Bonneville efforts such as Provider of Choice, allows Bonneville an "early seat at the table" for participation in Markets+, places Bonneville on a similar timeline to other entities in the West who are joining day-ahead markets, and maintains two viable market options. In addition, it is necessary for Bonneville to provide clear expectations to its customers, sovereigns, and stakeholders now to mitigate uncertainty and to collaborate on next steps.

2.4. Day-Ahead Market Framework

A day-ahead market is a centrally organized financial and physical electricity market where participants submit hourly resource offers and bids for load. The market optimization combines all offers and bids to determine the least cost energy dispatch to serve load while recognizing physical system constraints. If the market optimization determines the offers and bids to be economical, the participant receives a financially binding award. The resource offers can be updated with the market operator to reflect operational changes, with the ultimate real-time dispatches of resources serving all load economically given physical system conditions. Market participants ultimately receive settlements from the market operator for all resources and loads cleared through the market.

The market operator uses a SCUC and SCED[30] accompanied by a nodal network model with locational marginal pricing to create an optimized dispatch plan.[31] "Unit commitment" determines the optimal

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[27] *See* Mareldi Ahumada-Paras, Michael Mastrandrea, and Michael Wara, Stanford Climate and Energy Policy Program, *Grid Regionalization in the West: Reliability Benefits from Increased Cooperation in Electricity Markets and Operations* (Aug. 2024), *available at* https://woodsinstitute.stanford.edu/system/files/publications/Woods_Grid_Regionalization_White_Paper_v05_WEB.pdf.

[28] *See* Declaring a National Energy Emergency, Exec. Order No. 14156, 90 Fed. Reg. 8433, 8434 (Jan. 20, 2025).

[29] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment (Sept. 2020) at 3, *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

[30] As a reminder, SCUC stands for security-constrained unit commitment and SCED stands for security-constrained economic dispatch.

[31] *See* FERC, Security Constrained Economic Dispatch: Definitions, Practices, Issues, and Recommendations: A Report to Congress Regarding the Recommendations of Regional Joint Boards for the Study of Economic Dispatch Pursuant to Section 223 of the Federal Power Act as Added by Section 1298 of the Energy Policy Act of 2005, *available at* https://www.ferc.gov/sites/default/files/2020-05/final-cong-rpt.pdf.

combination of resources to bring online from those that are available for some or all of the operating day.[32] "Economic dispatch" determines the optimal output of all committed resources relative to bid-in or expected load and other resource output forecasts to minimize total cost to serve load.[33] To ensure that the unit commitment and economic dispatch are feasible, the optimization is "security-constrained," which means that the optimization must adhere to certain limits (known as "constraints") such as flow across transmission elements and maximum ramp rate of generators. For instance, if increasing the output of a generator that is otherwise economic to serve load would cause flow on a transmission element to exceed its limit, the optimization will instead increase the output of the next least-cost resource that does not cause the flow on that element to exceed its limit.

To incorporate these constraints into the optimization, the market operator has a full nodal network model showing the locations and relevant characteristics of all transmission elements and generation resources of a certain size as well as approximations to represent load across the area. The market operator receives updated constraint information in day-ahead and real-time data submittals from market participants and reliability entities. Transmission Operators and BAs update constraint information on the elements or system areas that have new or existing limitations. Resource Owners/Operators submit hourly offer information about the minimum and maximum amount of generation they are willing to sell and the associated price between those output levels, as well as resource limitations (e.g., ramp rate, minimum or maximum run time when committed, etc.).

For day-ahead optimization, the SCUC and SCED solve simultaneously across all 24 hours of the next operating day. For real-time optimization, the SCED solves for a set number of sub-hourly intervals for the applicable operating hour. In between the day-ahead optimization and the real-time optimization, the market operator runs additional SCUCs.[34] These intra-day SCUCs are used to ensure enough generation is online and available to serve expected load as input information changes, such as load forecast increases or an unexpected outage on a previously committed generation resource.

Finally, the market produces financial settlements for all energy traded and load ultimately served. Settlements are for all location-nodes for day-ahead and real-time resources generated and load demand, as well as other associated payments or charges. All centrally organized markets in the U.S. settle based on LMPs, which generally represent the incremental cost to serve another megawatt (MW) of load at a given location. LMPs are composed of the following pricing components: energy, losses, and congestion. In a day-ahead market framework, the award from the day-ahead solution is settled at the day-ahead LMP and is used as the financial reference point for settlement of energy in the real-time solution.

3. Public Process

In July 2023, Bonneville started its public process to evaluate day-ahead market participation including hosting 11 public workshops (see below for a list of workshops and their respective topics) to share and discuss potential benefits and risks. A high priority for Bonneville is ensuring that customers and stakeholders understand the day-ahead market proposals and have multiple opportunities to provide substantive feedback on the decision. Bonneville has accepted public comments and concerns and posted all the written comments on its day-ahead market process website.[35] Stakeholder comments have provided valuable information about concerns and issues and have had a direct impact on the decision process. Bonneville appreciates the robust engagement and the feedback it has received.

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[32] CAISO, Technical Bulleting 2009-06-05, Market Optimization Details § 2 (Nov. 19, 2009), *available at* https://www.caiso.com/Documents/TechnicalBulletin-MarketOptimizationDetails.pdf.

[33] *Id.* § 3.

[34] Referred to as "Reliability Unit Commitment" in Markets+ and "Residual Unit Commitment" in EDAM.

[35] Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.

Additionally, Bonneville coordinated with customers in the Provider of Choice public process to design power products that will be compatible with a day-ahead market for October 1, 2028 through September 30, 2044 contract period.[36]

Topics covered in the public workshops include:

No.	Meeting Date	Topics
1	July 14, 2023	• Why are we exploring day-ahead market participation? • Overview of public engagement for establishing a Bonneville policy direction on potential day-ahead market participation • Discussion on drafting Bonneville day-ahead market evaluation principles • Overview of day-ahead markets
2	September 11, 2023	• Update on day-ahead market development & update on developing GHG accounting in a day-ahead market • Bonneville will continue to supply electric power to customers in a day-ahead market • Draft day-ahead market evaluation principles • Review of comments received • Section 5(b) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act)[37] (Section 5(b))/day-ahead market compatibility • Tabletop scenario work with the Public Power Council
3	October 23, 2023	• Energy and Environmental Economics (E3) overview of Western Market Exploratory Group (WMEG) cost/benefit study • Initial takeaways from WMEG Result • Considerations for Bonneville's day-ahead market business case analysis
4	November 29, 2023	• Discussion of Section 5(b) obligations/day-ahead market compatibility • Review of Bonneville's policy direction public process • Considerations for Bonneville's day-ahead market business case • GHG Update and consideration of GHG business case
5	February 1, 2024	• Update on Bonneville's decision process and timeline for CY 2024 • Review of Bonneville's day-ahead market evaluation and decision criteria • Update on Bonneville's day-ahead market public comment tracking • Responses to public comments at this workshop
5.5	May 3, 2024	• Tabletop scenario refresh (from workshop 2) • Workshop 6 scenarios
6	May 8, 2024	• Review of Bonneville's Staff Recommendation on Day-Ahead Market Participation; update on decision process and timeline for CY 2024 • Baseline process and scenario discussions

[36] *See* Bonneville Power Administration, Provider of Choice (Post-2028), *available at* https://www.bpa.gov/energy-and-services/power/provider-of-choice.
[37] 16 U.S.C. § 839c(b).

7	June 3, 2024	• Review of Bonneville's comments on Pathways April 10 proposal and legal analysis • High-level congestion rent scenario • Congestion rent design • Congestion revenue scenario with congestion rights
8	July 18, 2024	• Update on the Pathways initiative • Day-ahead market from the transmission perspective
9	November 4, 2024	• Timeline update and key dates for CY 2025 • Update on Markets+ FERC filing and EDAM engagement • Transmission update • Bonneville's continued decision process • Evaluation of market governance developments • Bonneville's supplemental production-cost analysis/result interpretation
10	January 29 & 30, 2025	• Review of Bonneville's day-ahead market decision process • E3 Case Result – Hydro Operational Limitations Scenario • Expected transmission revenue impact • Day-ahead market participation & implementation fees • Day-ahead market seams, reliability and operational impacts
11	March 19, 2025	• Opportunity to ask clarifying questions of the draft policy

Based on stakeholder feedback, Bonneville also considered potential day-ahead market participation through the lenses of firmness of power supply and certainty of delivery. This Policy addresses firmness of power supply in section 6.2, focusing on ensuring adequate supply through resource planning. Certainty of delivery is addressed in section 6.7, which describes how a day-ahead market paradigm would build upon existing constructs. Section 5.2.5 on GHG accounting addresses how market designs can provide for transparent accounting of environmental attributes.

4. Day-Ahead Market Evaluation Process

Bonneville has been evaluating potential day-ahead market participation based on eight evaluation principles. This section provides further detail for each evaluation principle.

4.1. Discussion of Evaluation Principles

While potential benefits, like those listed in section 2.3, are an important part of Bonneville's evaluation, there are additional considerations for Bonneville to weigh in its evaluation. In its decision process, Bonneville is assessing the business case for day-ahead market participation based on both quantitative and qualitative evaluation components. Bonneville assessed day-ahead market participation based on the following evaluation principles. These principles were shared with stakeholders in public workshops and include revisions based on stakeholder feedback:

- Statutes – Bonneville meets its statutory, regulatory, and contractual obligations.
- Reliability – Bonneville maintains efficient, economical, and reliable delivery of power and transmission service to its customers.
- Reliability – Market design includes resource sufficiency and/or resource adequacy frameworks that ensure reliability.
- Business – Bonneville's participation is supported by a sound business rationale.

- Strategy – Bonneville's participation is consistent with Bonneville's 2024-2028 Strategic Plan.
- Governance – The market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Decision-making and stakeholder engagement occur in a transparent and inclusive manner.
- Customers – Bonneville's evaluation of day-ahead market participation includes transparent consideration of the commercial and operational impacts on its products and services.
- GHG – Bonneville will evaluate how participation will impact GHG emissions attributed to the federal system and its regional firm power customers' ability to comply with applicable state carbon programs. Participation must maintain the value of the low-carbon nature of the federal system to the extent possible.

The sections below highlight how a day-ahead market meets our evaluation principles.

4.1.1. Statutes – Bonneville meets its statutory, regulatory, and contractual obligations.

Bonneville has not identified any legal barriers to day-ahead market participation. See Appendix A for a discussion of Bonneville's statutory authority to participate in Markets+.

4.1.2. Reliability – Bonneville maintains efficient, economical and reliable delivery of power and transmission service to its customers.

Maintaining the reliability of the power and transmission systems for all of Bonneville's customers is one of the most important aspects of Bonneville's various roles. Indeed, reliability is foundational to accomplishing many of the other principles, objectives, and goals upon which Bonneville focuses.

Day-ahead markets and market operators do not assume any of the reliability roles of a utility. Bonneville will retain its reliability roles, such as Transmission Planner, BA, and TOP, and remain responsible for compliance with applicable NERC reliability standards. Further, Bonneville and its federal generating partners maintain full control of federal resources, including authority to manage output and make energy available to the market. Thus, Bonneville will continue to serve its direct role in operation of the federal power and transmission systems and maintaining system reliability.

As described in Section 2.3, participating in a day-ahead market will provide Bonneville opportunities to support or improve reliability due to system optimization and geographic diversity benefits. As Bonneville moves into a day-ahead market implementation phase, Bonneville will continue to assess any potential reliability concerns, identify and design necessary mitigations, and work with the market operators to ensure the markets are able to support those mitigations where necessary.

4.1.3. Reliability - Market design includes resource sufficiency and/or resource adequacy frameworks that ensure reliability.

Bonneville believes that it is important for a day-ahead market to address long-term Resource Adequacy (RA) as well as short-term resource sufficiency. Resource sufficiency generally refers to resources' availability to produce power (energy and capacity) to serve the expected load in the short term (e.g., moving into the next week, day or hour). RA generally refers to long-term planning and acquisition of resources, if needed, to serve the expected peak or critical load in a season or upcoming year. RA aims to have enough "steel in the ground" (resources built and accessible) to serve a forecasted peak load, while resource sufficiency considers the current operational landscape (e.g., outages or derates, up-to-date variable generation and load forecasts, etc.). The two concepts work in concert to minimize scarcity, emergency, or loss-of-load events.

In a day-ahead market, market participants continue to be responsible for their own RA and sufficiency, and thus they are obligated to bring a resource portfolio (including power purchases) able to meet their expected load to the market; the market is then able to optimize the dispatch of resources, along with any independently-offered resources, creating a more efficient and economical load service plan reflecting the current system landscape. Market design frameworks try to ensure that market participants are held accountable for this responsibility to receive the shared benefits of an integrated market through penalties or limitations on market access.

Both day-ahead market options include an evaluation for resource sufficiency. EDAM has a set of resource sufficiency evaluation tests and Markets+ has a must-offer obligation, both of which compare an entity's day-ahead load and uncertainty requirements to its available resources to ensure they have sufficient resources to meet their loads or are held accountable. However, as explained further in section 5.2.2, Bonneville prefers the design in Markets+, primarily because it also includes a long-term RA requirement. Markets+ includes a standardized RA requirement, requiring all load responsible entities (LREs)[38] to participate in the Western Resource Adequacy Program (WRAP) administered by the Western Power Pool. While the CAISO BAA has its own RA framework, this framework is not extended to other entities outside of CAISO's BAA in general, and the EDAM design does not include a requirement for entities to participate in any RA program. Bonneville believes that Markets+ requiring participation in WRAP, a standardized RA framework, will better meet this principle.

4.1.4. Business - Bonneville's participation is supported by a sound business rationale.

With the emergence of day-ahead market offerings by both CAISO and SPP, most entities in the Western Interconnection are evaluating participation in an organized day-ahead market. While economic value is an important factor, a decision about day-ahead market participation encompasses many considerations beyond just economic value.

Production Cost Modeling (PCM) provides an initial analysis of various simulations. Bonneville joined WMEG and contracted with E3 to explore the economic possibilities. In Section 5.1 Bonneville describes the benefits and limitations of the PCM studies. However, for the evaluation of a day-ahead market, a sound business rationale must encompass factors beyond the short-term economic results. The long-term industry trends must also be considered. These trends could include more entities joining day-ahead markets, new variable energy resources integrating into the system which causes power purchase changes, and the potential development of an RTO. Joining a day-ahead market allows Bonneville to continue to align with the majority of the industry on the business of power markets.

4.1.5. Strategy - Bonneville's participation is consistent with Bonneville's Strategic Plan.

The "Evolving Grid" sets the agency's path for the Pacific Northwest, including the use of Bonneville's transmission system. Through the evolution, Bonneville will maximize the value of the federal hydropower and transmission systems. As the needs of its customers evolve, so must the products and services it offers. Bonneville must address customer demand for more renewable generation and amplifying RA concerns brought about by a changing resource mix. An objective in meeting this goal is fostering market evolution to enhance the delivery of cost-effective, reliable power and transmission service while modernizing business systems and processes. The flexible and reliable power of the Federal Columbia River Power System (FCRPS), coupled with the expansive high-voltage transmission grid, is the bedrock Bonneville will build on to meet these future needs.

4.1.6. Governance – The market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Decision-making and stakeholder engagement occurs in a transparent and inclusive manner.

Bonneville performed a rigorous assessment of day-ahead market offerings from a governance perspective because insufficient independence and limitations on stakeholder engagement pose risks to creating a fair

[38] A Load Responsible Entity (LRE) is an entity directly responsible for ensuring an electrical load is served.

and equitable market that brings equitable value to all participants. Risks arise from market governance that retains authority for a single state, entity, or customer class.

At the highest level, the decision-making body for the market must be free of disproportionate obligation to the policies of a single state, entity, or customer class to ensure that market design is on an equal footing for all participants, including Bonneville. In CAISO markets, Bonneville has observed disadvantages for market participants outside of California during market design development and in times of outlier events.[39] The staffing and process for decision development and stakeholder engagement should equitably weigh the policies or priorities of all states, entities, and customer classes. Bonneville finds that the governance structure for Markets+ meets that standard.

As it engaged in the stakeholder processes for the development of both markets, Bonneville strongly advocated for the inclusion of sound independent governance principles in market design. Bonneville believes its efforts have positively impacted the governance structures of both EDAM and Markets+.

4.1.7. *Customers - Bonneville's evaluation of day-ahead market participation includes transparent consideration of the commercial and operational impacts on its products and services.*

Bonneville has conscientiously considered the needs of its large customer base as it evaluated joining a day-ahead market, including public customer/stakeholder workshops[40] exploring how a decision to participate in day-ahead markets may impact different customer types and how its various power and transmission products and services may work in a day-ahead market. Bonneville also collaborated with customers to design a long-term power sales contract[41] that includes provisions to adapt to potential day-ahead markets to ensure the flexibility to meet a changing landscape. Further, in the public processes for EDAM and Markets+ development, Bonneville advocated for policies and designs to unlock additional value from the federal hydropower and transmission systems that benefit Bonneville and its customers.

Bonneville expects to continue holding day-ahead market public workshops. It will also work through various day-ahead market specifics in its rate cases and tariff terms and conditions proceedings, contract negotiations, business practice change forums, etc., as appropriate. Throughout these various processes, Bonneville will continue to comprehensively address the impacts of day-ahead market participation on the products and services it offers to customers.

4.1.8. *GHG - Bonneville will evaluate how participation will impact GHG emissions attributed to the federal system and our regional firm power customers' ability to comply with applicable state carbon programs. Participation must maintain the value of the low-carbon nature of the federal system to the extent possible.*

Bonneville is not subject to any state GHG programs in the region. However, Bonneville customers have repeatedly expressed the importance of the low-carbon attributes of their power purchases from Bonneville.[42] Bonneville markets power from the federal hydropower system, Columbia Generating station,

[39] Examples include wheel through priorities in August 2020 and greenhouse gas allocation market design.
[40] Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.
[41] Bonneville Power Administration, Provider of Choice (Post-2028), *available at* https://www.bpa.gov/energy-and-services/power/provider-of-choice.
[42] Examples of customer comments related to GHG emissions can be found in Bonneville's Final Energy Imbalance Market Close-Out Letter § 5.2.3 (Sept. 2021), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalance-market/final-eim-close-out-letter.pdf (full comments available at https://publiccomments.bpa.gov/CommentList.aspx?ID=421); Bonneville's Provider of Choice Policy Record of Decision § 8 (Mar. 2024), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/2024-rod/rod-20240321-bonneville-power-administration-provider-of-choice.pdf (full comments available

and other resource acquisitions and market purchases. Today, market purchases are the only resources in the federal system to which state programs attribute emissions. These purchases are an important component of Bonneville's power supply and have historically comprised 3 to 10% of the FCRPS.

Organized markets change GHG accounting dynamics because, absent a GHG accounting design, the market does not specify which resources are dispatched to meet a particular load. For example, when Bonneville joined the EIM in May 2022, the volume of unspecified purchases included in Bonneville's federal system fuel mix slightly increased. This was due to increased transfers of energy to meet load imbalance between Bonneville's BAA and other BAAs, which states accounted for at an unspecified emission factor. Currently, WEIM only employs a GHG accounting mechanism to support implementation of California's cap-and-trade program.

Both EDAM and Markets+ developed mechanisms to support the implementation of carbon pricing programs generally including California's program and Washington's cap-and-invest program. Over 60% of Bonneville's long-term power sales are to customers in Washington and are subject to the state's cap-and-invest program as well as the state's Clean Energy Transformation Act. Bonneville also has customers in Oregon that are subject to Oregon's GHG reporting requirements. Bonneville has participated in day-ahead market GHG accounting conversations mindful of impacts to customers in those states with the goal of ensuring customers can continue to claim low-carbon attributes associated with power purchases from Bonneville. As discussed in section 5.2.5, Bonneville believes the Markets+ design better reflects environmental attributes related to its firm power sales to its customers.

5. Day-Ahead Market Participation Evaluation

Bonneville has spent over two years evaluating whether to join a day-ahead market, and if so, which of the two available day-ahead markets options Bonneville should join. With the principles described in Section 4 in mind, Bonneville has considered quantitative analyses, market design elements, footprint, and other relevant information in its evaluation. On the whole, Bonneville finds that joining a day-ahead market will result in benefits to its customers.

Bonneville contracted with E3 to analyze economic costs and benefits using PCM. The initial PCM results depicted a wide range of economic benefits for day-ahead market participation. Bonneville's assessment is that the forecasted benefits justify participation in either EDAM or Markets+. Subsequent sections of this document further discuss the initial PCM results as well as supplemental analysis Bonneville contracted for with E3.[43] These results should not be viewed with the expectation of achieving specific forecasted revenues. The PCM results are forecasts that can be influenced by other factors that may alter the projected outcome. For example, modifications to market design items such as Congestion Rent, Scarcity Pricing, or LMP computation can impact benefits. PCM models also do not account for qualitative elements such as differences in market governance structure that can also produce quantitative impacts.

Overall, the PCM results showed:

- Participation in the EDAM market produces the highest net cost benefit in the cases studied.
- Markets+ offers the lowest cost to serve load but also forecasts reduced generation revenue.

at https://publiccomments.bpa.gov/CommentList.aspx?ID=480); and in customer comments received to-date in Bonneville's Day-Ahead Market process (comments available at https://www.bpa.gov/learn-and-participate/projects/day-ahead-market).

[43] Energy and Environmental Economics, WMEG Cost Benefit Study (CBS), BPA Day-Ahead Market Participation Workshop presentation (Oct. 23, 2023), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/e3-wmeg-benefits-study.pdf; Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf.

- Although the net cost looks favorable, remaining a WEIM-only participant carries significant risk not easily reflected in the quantitative case result.

As mentioned in section 4, one of the eight evaluation principles is governance. Bonneville is specifically looking for a market that has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Bonneville's evaluation considers the relevant factors associated with governance structures under both Markets+ and EDAM to identify the best governance structure available for Bonneville's decision regarding day-ahead market participation. RA and resource sufficiency are included in the reliability evaluation principle in market design. RA aims to have enough physical resources (both transmission and generation) to serve a forecasted peak load well into the future (often years or multiple months), while resource sufficiency considers the current operational landscape (outages or derates, up-to-date variable generation and load forecasts, etc.).

Price formation and market power mitigation ensures that market rules provide appropriate price signals, which compensate resources at prices that reflect both the value of the services that resources provide to the market and the operational conditions under which the resource is awarded. EDAM and Markets+ are broadly similar in the way they model constraints and manage transmission, with some key differences, particularly regarding allocation of congestion rents, which are described in section 5.2.4. The market design for GHG accounting—how resources and their associated emissions are assigned to market participants—is critical to ensuring Bonneville's customers can continue to claim the low-carbon attributes of their federal system power purchases for applicable state programs or for their own utility purposes.

This section discusses the economic and market design benefits associated with Bonneville's Policy direction to participate in Markets+ with emphasis on governance, RA and resource sufficiency, price formation and market power mitigation, transmission and congestion rent, and GHG.

5.1. Economic Costs/Benefits Analyses

As part of its day-ahead market evaluation, Bonneville assessed costs and benefits using PCM. PCM is an industry-standard approach for analyzing costs and revenues associated with energy trading and load service. PCM is explained below in section 5.1.1.1.

Many entities in the Western Interconnection, including Bonneville, employ PCM in their evaluations of day-ahead markets, in integrated resource planning, and when assessing long-term transmission expansion costs. Bonneville also included consideration of the economic impact to its Power and Transmission business lines, reflecting both the PCM results and additional considerations. Further, Bonneville has considered the implementation costs (both internal to the agency and those paid to the market operator) as well as on-going participation fees associated with the day-ahead market options. These analyses and considerations are discussed in this section.

5.1.1. Production Cost Modeling

Bonneville was part of two separate cost-benefit analyses using PCM as part of its day-ahead market evaluation. Bonneville joined the WMEG in the summer of 2022. WMEG is a group of 25[44] BAAs within WECC that came together to examine participation in day-ahead market offerings. WMEG hired E3 to provide PCM analysis for each respective BAA across varying market footprints and varying years (2026,

[44] The 25 WMEG members represented are AEPCO, APS, Avista, Balancing Authority of Northern California (BANC), Black Hills Energy, Bonneville, Chelan County PUD, El Paso Electric (EPE), Grant County PUD, Idaho Power Company, Los Angeles Department of Water & Power (LADWP), NV Energy, PacifiCorp, Public Service of new Mexico (PNM), Platte River power Authority, Public Service of Colorado (PSCO), Puget Sound Energy (PSE), Salt River Project (SRP), Tacoma Power, Tucson Electric Power (TEP), Tri-State Generation and Transmission Authority (TSGT), and Western Area Power Administration (WAPA), which was modeled in 5 separate areas (SNR, CRCM, LAP, WALC/DSW, and WAUW). The rest of the WECC was represented as non-WMEG.

2030, 2035). Following the WMEG analysis, Bonneville contracted directly with E3 in 2024 for supplemental analysis using the WMEG data set to test additional market footprints and sensitivities of a number of other variables. This section discusses both sets of PCM analyses.

5.1.1.1. What is Production Cost Modeling?

PCM is an industry standard simulation software tool that attempts to model a day-ahead market by producing a least-cost dispatch to serve load based on a set of static input data. PCM incorporates SCUC and SCED, which are the processes the day-ahead market uses to optimize participants' loads, resources, and transmission.[45] The analysis produces hourly generation dispatches and associated electricity production costs to serve load based on numerous operational inputs. Such inputs include loads, generation resources, weather, fuel, and transmission connectivity/constraints.

There are many underlying assumptions that must be made to model such a complex system. In particular, the study results are highly dependent on the composition of the market footprint (i.e., which load, generation, and transmission are included in the market optimization). Identifying a market footprint requires assumptions about which market a utility may choose to join. The footprint composition brings together the resources that will be optimized to serve load at the least cost and is constrained by the transmission connectivity that is utilized by the market to deliver all the footprint resources to load. Adjusting the market participants, and therefore changing the footprint, can offer additional load to be served, additional generators to serve load, and new transmission connectivity that expands the possible solutions of the market optimization. Therefore, the composition of the market is an important and influential component in PCM.

PCM must also assume the cost associated with transmission within a market (usually assumed to be zero) and transmission and other incremental "friction" between markets (sometimes called the "hurdle rate"). Hurdle rates represent the "friction" between markets, which could come in the form of actual costs associated with sales across markets, or as a representative cost representing the inefficiency of two separate optimizations (one for each footprint) as opposed to a single optimization. This could show up as price divergence between markets such that the price in one market must be high enough to incentivize exporting from the other market. Much like the footprint composition, the adjustment (i.e., reduction and variation) in the hurdle rate also proved to be a notable operational model input.

PCM is a powerful tool that relies on a range of assumptions to produce modeling results that provide direction and magnitudes of market participation outcomes. PCM comes with both strengths and limitations. It produces simulations that optimize dispatch of resources to meet demand at the lowest possible cost, facilitate long-term planning and investment decisions, inform policy making and potential regulatory impacts, and provide insight for market dynamics and analysis to help understand price trends and identify opportunities for cost savings. The limitations of PCM are discussed further in the section below.

5.1.1.1.1. Production Cost Modeling Limitations

PCM is a useful industry-standard tool, however, it is accompanied by certain limitations. In PCM, a range of assumptions are required to produce effective modeling. While PCM results are useful in providing market participation outcomes, these results do not represent an exact expected outcome. Moreover, while PCM is a valuable industry standard method to simulate friction and hurdle rates, it is prudent to acknowledge that actual real-world values of friction and hurdle rates may differ from simulated results because of the inherent complexity, uncertainty, and variability associated with the assumptions and data quality in the model. For example, some entities view long-term firm transmission cost as a sunk cost and therefore do not include it in their price evaluation in their decision of whether they transact between

[45] For information on day-ahead market processes, see section 2.4 above.

markets. Further, there is not a single value that uniformly represents the risk that sellers are willing to take on, and thus a modeled hurdle rate can never perfectly represent reality.

In the supplemental analysis, E3 ran case studies to simulate scarcity events through the application of stressed conditions.[46] Specifically, E3 applied stressed conditions to the following market footprints 1) Business-as-usual, 2) West-wide market, 3) Alt Split 4A (current market declarations). In the results of these cases, net costs showed a minimal decline and prices in the model did not rise nearly as significantly as would be expected.

The minimal change in forecasted benefits in the PCM results stand in stark contrast to real-world outcomes from recent events such as the 2024 Martin Luther King, Jr. (MLK) holiday weekend winter storm. During that short period of time, the region faced significant competition for available resources to meet load accompanied by hourly prices exceeding the WECC soft-offer cap of $1,000 per megawatt-hour (MWh). There was also significant congestion on key transmission paths and congestion revenues within WECC exceeded $100 million dollars. The 2024 MLK weekend event represents an extreme outlier that a PCM cannot replicate. A typical scarcity outlier, experienced over a few days to a week, will likely see multi-hour, peak load block prices rise to triple digits. Frequently, evening hourly prices will rise above this into the mid-to-high hundreds, sometimes exceeding the WECC soft-offer cap, as loads are peaking and renewable resources are ramping down. The pricing levels reflected in the PCM captured neither the extreme event like a 2024 MLK, nor the more typical scarcity event of sustained elevated prices. The PCM pricing outputs simply do not reach the magnitude nor the daily sustained level of pricing that we would expect to see, even under the stressed load parameters. The minimal decline in net cost results for stressed conditions in the PCM study demonstrates that the financial impacts of a scarcity event are not captured in the modeling. Regardless of day-ahead markets, such events occur, and Bonneville simply acknowledges that these risks are not fully represented in the PCM study.

Additionally, PCM studies do not reflect various market design elements such as GHG pricing programs, market power mitigation, out-of-market actions, and market bid caps. Lastly, PCM results cannot account for market design changes and modifications to market rules influenced by the market's governance structure. Bonneville explores a number of these design elements in section 5.2.

5.1.1.2. WMEG Study

Bonneville participated in WMEG with 24 other BAAs in a joint exploration of day-ahead market participation. The WMEG group sought economic analysis results that would help forecast costs and benefits associated with day-ahead market participation for each BAA participating in the study. E3 used PCM to develop categorical results, discussed below in section 5.1.1.2.2, for each BAA. The categorical results were summed together to create a single "net cost" number, which was intended to indicate whether costs or benefits were likely for a given BAA's participation in a day-ahead market. The PCM studies were modeled across three different time horizons of 2026, 2030, and 2035. The 2026 scenarios depicted initial day-ahead market launch. The 2030 scenarios assumed maturation of the day-ahead market by layering on some BAA consolidation and an ancillary services market. The 2035 scenarios modeled a full RTO, which consisted of a single consolidated BAA (however, it did not include any estimates of transmission cost savings). Load, generation, and transmission were also augmented in future cases, reflecting anticipated growth in each category. Each participating BAA received only their respective results, though they were free to share their results on a wider basis. Bonneville publicly released its WMEG PCM results in the fall

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[46] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation at 4, 11 (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf (Task 3: Low Water Year (+ Stressed Load)).

of 2023 in public workshop 3.[47]

5.1.1.3. WMEG Data Elements

Each WMEG member provided generation, transmission, and load data to E3 for use in the PCM to model market activity and calculate categorical costs and benefits. This data was retained by E3 following the completion of the initial WMEG study and used in the supplemental analysis that Bonneville requested.

5.1.1.3.1. WMEG Cost Benefit Categories

The PCM results consisted of eight distinct categories: load costs, generation costs, reserve costs, reserve revenue, generation revenue, wheeling revenue, congestion revenue, and GHG revenue. It is important to emphasize that the results are reported such that costs are represented as positive numbers and revenues are represented as negative numbers (as indicated by the positive or negative sign in the category list below). The eight categories were then added together to create a "net cost," which indicated whether the WMEG member should expect a cost or benefit. Again, a positive "net cost" indicated cost to the WMEG member because of day-ahead market participation, and a negative "net cost" indicated benefits to the WMEG member because of day-ahead market participation.

Net Variable Cost = Load Cost + Generation Cost + Reserve Cost – Reserve Revenue – Generation Revenue – Wheeling Revenue – Congestion Revenue – GHG Revenue

The following are the categories from the PCM results accompanied by their applicable sign:

PCM Results Categories (as defined in E3's Western Markets Exploratory Group: Western Day -Ahead Market Production Cost Impact Study)*[48]*

1. Load Costs (+)

Entities incur a cost to serve load based on (a) the hourly quantity of load (in MWh) that the entity is obligated to serve in each zone of the model times (b) the hourly zonal energy price

2. Generation Costs (+)

The model reports variable production costs for each generating unit as the sum of fuel costs, startup costs, and variable O&M cost for that resource. Generation Costs are attributed to each entity as (a) the total variable production cost of the unit times (b) the percentage share of that unit that is owned or contracted to the entity.

3. Reserve Costs (+)

In the Business-as-Usual (BAU) Case, E3 enforces ancillary service reserve requirements at the BAA level but does not settle these products at a market clearing price. For all the market cases, day ahead forecast error reserves are enforced at the level of a subregion within each market (e.g. the Northwest portion of Markets+), and each entity is assigned a Reserve Cost responsibility based on of (a) the hourly quantity of reserves that entity needs times (b) the hourly market price for reserves within that market sub-region.

4. Reserve Revenue (-)

Each entity is also awarded Reserve Revenue from the market based on (a) the quantity of reserves that are contributed by generators owned or contracted by the entity times (b) the hourly market price for reserves

[47] For results, see Bonneville Power Administration, Day-Ahead Market, *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market (*see* Workshops, Oct. 23, 2023, WMEG Materials).

[48] Energy and Environmental Economics, Western Markets Exploratory Group: Western Day Ahead Market Production Cost Impact Study at 9-11 (June 2023), *available at* http://www.oasis.oati.com/woa/docs/NEVP/NEVPdocs/3._E3_WMEG_Western_Day_Ahead_Market_Production_Cost_Impact_Study_-_Final.pdf.

within that market subregion. In the 2030 and 2035 CBA cases, Reserve Costs and Reserve Revenues are calculated separately for each reserve product (spinning reserves, non-spinning reserves, and regulating reserves, as well as day ahead forecast error reserves)

5. Generation Revenue (-)

Generation Revenue is first calculated for each resource based on (a) the hourly energy produced by the generator, times (b) the hourly price at the generator's zone. This Generation Revenue is then attributed to each entity based on the percentage share of each resource that is owned or contracted to the entity

6. Wheeling Revenue (-)

Wheeling revenue is revenue that transmission providers earn by selling transmission service. In the BAU Case, total Wheeling Revenue is calculated in the model for each entity based on the product of (a) the amount of energy exported over transmission lines connected to that entity, times (b) the OATT rate or market wheeling rate applicable that BAA or transmission entity, plus an additional $/MWh charge for bilateral day ahead market friction. In the RT stage of the BAU Case, wheeling is not charged for transactions between entities in the WEIM or WEIS market. In the DA markets cases, total wheeling revenue is first determined at a market-footprint level based on the (a) amount of energy flowing exported over transmission lines connected to each market footprint times (b) the load-weighted average of OATT rates of zones participating in that market, plus an additional $/MWh charge for transactional friction on seams between the markets. This total market wheeling revenue is then distributed among market participants based on each participant's percentage share of total load in the market (load-ratio share basis).

7. Congestion Revenue (-)

Price differentials between zones due to transmission constraints creates congestion between entities, resulting in loads paying higher prices than remote generators receive on the other side of congested interface. The value of this difference is assigned back to the entities in the BAU case and for lines within each market footprint. Congestion on the border of each market is allocated among all participants in that market on a load ratio share basis.

8. GHG Revenue[49] (-)

Revenue associated with any MW of generator output that was attributed as an import into a state with a pricing program (CA/WA). The way Bonneville elected to model its resources in the E3 studies resulted in minimal attribution of imports.

9. Net Cost (+) OR (-)

The difference between the Net Variable Costs for an entity in a market case compared to that entity's Net Variable Revenues.

5.1.1.3.2. Bonneville's Modified Calculation of Net Cost

As Bonneville examined the PCM results, it became evident that certain categories could be set aside, and a net cost could be recalculated with the remaining categories. Bonneville set aside generation cost, reserve cost, and reserve revenue because they were a static or negligible value, meaning there was zero or almost zero difference among scenarios. Further, after some conversation with E3 regarding wheeling revenue, Bonneville and E3 determined that the study approach did not attempt to capture existing transmission contracts. Instead, it assumed that all transactions outside of or between markets required incremental purchase of transmission and that all transactions within a market required no purchase of transmission. These assumptions do not approximate likely transmission purchase patterns for Bonneville customers and therefore do not appropriately reflect a likely outcome of market participation. Therefore, Bonneville

[49] The text of Result Category No. 8 has been modified from the E3 report for clarity.

removed the wheeling revenue category from the net cost computation when analyzing the PCM results.[50] Based on the negligible value category exclusions and wheeling revenue exclusion, the results discussed throughout the rest of this document focus on PCM results for load costs, generation revenue, congestion revenue, and GHG revenue, and a net cost summing those four categories (reported as "Net Cost without Wheeling" for clarity). Bonneville separately provides an analysis of the potential impact to transmission revenues in section 5.1.1.7.

Net Cost = Load Cost – Generation Revenue – GHG Revenue – Congestion Revenue

5.1.1.3.3. WMEG Footprints

Of the 38 BAAs in WECC, spanning from Canada to Mexico, 25 participated in the WMEG study. In all cases except for a "business as usual" (BAU) case, each BAA in WECC was designated to fall within one of two categories to comprise a day-ahead market footprint:

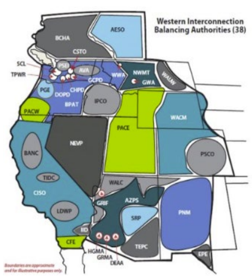
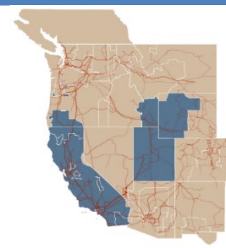
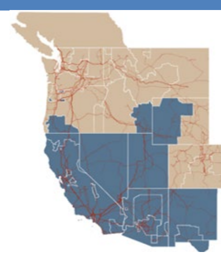
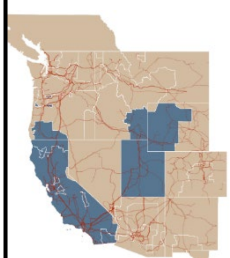
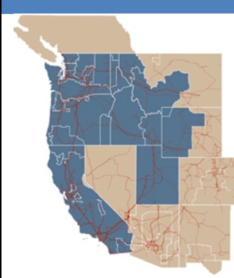
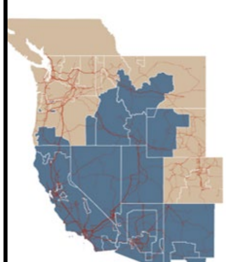
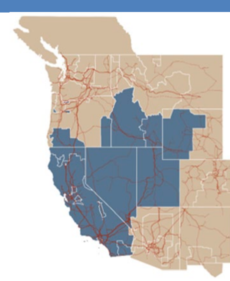
1) The BAA participates in EDAM,

2) The BAA participates in Markets+

During the initial 2023 PCM analysis, WMEG members designed a number of footprint scenarios representing the footprints that they determined were most plausible to test the impacts of different market footprints on the benefits. WMEG also included a BAU scenario to represent continued bilateral trading without any entities joining a day-ahead market. These footprints are shown in Table 1 on the next page.

[50] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation at 20.

Table 1 | Footprints used in WMEG studies

Business-as-Usual	Main Split
 This footprint was intended to model the operational and trading world as it exists today. Bilateral trading (no centralized market) in day-ahead; EIM & EIS cover most of WECC in real-time stage	 PacifiCorp (PAC) + all of California (including Western Area Power Administration Sierra Nevada Region (WAPA SNR)) in EDAM; rest of WECC in Markets+
EDAM Bookend	**Alternative Split 1**
 All US WECC in EDAM; British Columbia Hydro only in Markets+	 PAC + California (excluding WAPA SNR) + SW (AZ + NM + NV) in EDAM; rest of WECC in Markets+
Markets+ Bookend	**Alternative Split 2**
 PAC, CAISO, Los Angeles Department of Water & Power. Turlock Irrigation District, Balancing Authority of Northern California (BANC) (not WAPA SNR) in EDAM; rest of WECC in Markets+ (including WAPA SNR)	 PAC + California (including WAPA SNR) + NW (WA, OR, ID, NWMT) in EDAM; rest of WECC in Markets+
Alternative Split 3	**Alternative Split 4**
 PAC + California (excluding WAPA SNR) + SW + ID + NWMT in EDAM; rest of WECC in Markets+	 PAC + California (excluding WAPA SNR) + ID + NV in EDAM; rest of WECC in Markets+ [Same as Markets+ Bookend, but NV & ID move to EDAM]

5.1.1.3.4. Bonneville's WMEG PCM 2023 Results

Table 2 shows a summary of Bonneville's results across the footprint scenarios. The top half of the table reflects the categorical results as absolute costs (positive numbers) or revenues (negative numbers). The bottom half calculates the delta result for each scenario relative to the BAU scenario. Again, a positive number represents an increased cost or a decreased revenue (and is accompanied by a red dot), and a negative number represents a decreased cost or an increased revenue (and is accompanied by a green dot).

The full set of Bonneville's initial WMEG results are available on Bonneville's website.[51]

Table 2 | Bonneville's WMEG Results (Fall 2023, units in millions of dollars)

	A	B	C	D	E	F	G	H	I	J
1	**Footprint**									
2		**Cost/Benefit Category**	**BAU (2026)**	**EDAM Bookend (2026)**	**Main Split (2026)**	**Markets Bookend (2026)**	**Alt Split 1 (2026)**	**Alt Split 2 (2026)**	**Alt Split 3 (2026)**	**Alt Split 4 (2026)**
3	**Category Value**	Load Costs	921	944	924	902	919	982	840	861
4		Gen Costs	131	131	131	131	131	131	131	131
5		Gen Revenues	-1341	-1490	-1370	-1329	-1360	-1515	-1152	-1220
6		Congestion Revenues	-50	-60	-53	-53	-48	-49	-51	-48
7		GhG Revenues	0	0	-1	-1	-1	0	-1	-1
8		**Net Costs w/o Wheel**	**-339**	**-475**	**-369**	**-349**	**-359**	**-451**	**-233**	**-277**
9	**Δ Category vs. BAU**	Δ Load Cost		23	3	-19	-2	61	-81	-60
10		Δ Gen Revenue		-149	-29	12	-19	-174	189	121
11		Δ Congestion Revenue		-10	-3	-3	2	1	-1	2
12		Δ GhG Revenue		0	-1	-1	-1	0	-1	-1
13		**Δ Net Cost w/o Wheel**		**-136**	**-30**	**-10**	**-19**	**-112**	**107**	**62**

Green = Benefit Greater than BAU **Red = Increased Cost from BAU**

Starting with the top half of the table, the PCM results forecast Bonneville to achieve net benefit in each of the eight cases in Table 2 (see row 8). Moving to the bottom half of the table, benefits greater than BAU are achieved in five out of seven footprints (all footprints except Alt Split 3 and Alt Split 4). Alt Splits 3 and 4 results forecast reduced benefits relative to BAU. While those footprints project significant cost savings in serving load,[52] the reduction in projected benefits relative to BAU is driven by generation revenues declining[53] more than the load costs decline. The generation revenue declines are driven by lower marginal prices observed in these footprints, as Bonneville is a net exporter in the generation data provided, resulting in the impact to revenue outweighing the savings to load.

Notably, Bonneville determined that the BAU scenario studied by E3 assumes all utilities forgo day-ahead market participation and cannot account for what entities will do in the long term. As discussed above in section 5.1.1.2.4, the BAU case fundamentally assumes continued use of bilateral trading activity as the primary tool for energy trading and limited organized market activity (i.e., real-time only). With many entities in WECC evaluating participation and declaring intent to join organized day-ahead markets, the bilateral world, as it is today, is not expected to persist. Bonneville included modeled costs and benefits relative to BAU to provide a sense of the magnitude, and the direction of the impact day-ahead market participation has relative to today. BAU does not represent a realistic future scenario.

5.1.1.4. Bonneville's Supplemental Cost/Benefit Analysis 2024

Bonneville engaged E3 to perform additional supplemental analysis to enhance its modeling and assumptions for its evaluation of potential day-ahead market participation. Following the release of the WMEG PCM results and review of stakeholder comments on Bonneville's WMEG results, Bonneville requested E3 to assess additional market footprints and identified scenarios or variables. For the supplemental tasks that used years 2030 and 2035, there were no market maturation pieces layered on the analysis. The new studies applied only load growth, modifications to generation resources (e.g., new builds and retirements), and additions to the transmission grid (e.g., new transmission lines) to the respective year-based cases. The additional PCM analyses are listed below. The full set of Bonneville's PCM results are

[51] Bonneville Power Administration, Day-Ahead Markets *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.
[52] Alt Split 3 Load Cost reduced by $81m as shown in cell I9; Alt Split 4 Load Cost reduced by $60m as shown in cell J9.
[53] Alt Split 3 Gen Rev declines by $189m as shown in cell I10; Alt Split 4 Gen Rev declines by $121m as shown in cell J10.

available on Bonneville's website.[54]

Note: During the development and execution of the supplemental analysis, Bonneville and E3 identified an issue regarding data underlying the "generation revenue" category. The generation values supplied by Bonneville to E3 were reflective of all generation, including generation applicable to the Slice product. Bonneville and E3 decided to apply a 15% reduction to generation revenue results in the supplemental analysis to ensure generation revenue more accurately reflected Bonneville's estimated share of generation. This reduction was discussed with all stakeholders during the public workshop on November 4, 2024.[55]

5.1.1.4.1. Supplemental Analysis Tasks

1) (Single West-wide Market) | Compute PCM cost benefit values for Bonneville for the EDAM Bookend Footprint for 2030 and 2035.
2) Lower Market to Market Hurdle Rates | Adjust the Market-to-Market hurdle rates by running three sensitivities that progressively reduce the hurdle rates.
3) Low Water Year (& Stressed Conditions) | Compute PCM cost benefit values for Bonneville for reduced hydro resources due to poor rain and snowpack. Model increased loads to mimic stressed conditions resulting from a multi-day heat and multi-day cold event.
4) Bonneville WEIM-Only | Compute PCM cost benefit values for Bonneville where Bonneville decides not to participate in a day-ahead market but remains a participant in CAISO WEIM. Neighboring and adjacent BAAs proceed with day-ahead market participation.
5) Additional Transmission Capacity | Compute PCM cost-benefit values for Bonneville where transmission connectivity between the Pacific Northwest and the Desert Southwest is increased.
6) Potential Capacity Value | Estimate the range of potential capacity benefits associated with day-ahead market participation.
7) Market Seam at California Border | Compute PCM cost benefit values for Bonneville where only entities lying within the state boundary of California participate in EDAM.
8) Alt Split 4A – Market Declarations | Compute PCM cost benefit values for Bonneville utilizing a two-market footprint that reflects the current market declarations and leanings.
9) Alt Split 2NV Pacific Northwest & Nevada join | Compute PCM cost benefit values for Bonneville where the Pacific Northwest, California, Nevada, and PAC BAAs are modeled as participants in EDAM while the Desert Southwest BAAs are modeled in Markest+.

Supplemental Analysis that was identified but unable to be modeled in PCM - No results were provided by E3

1) Market Interactions with WRAP | Understanding the potential difference in ability of either market's rules & practices to enable realization of RA benefits.
2) GHG Regulation | Understanding the impact that Markets+ vs. EDAM rules regarding GHG import treatment and pricing specific to the treatment of resources contracted to load in a GHG zone.

5.1.1.4.2. Supplemental Analysis Footprints

The supplemental analysis used several of the initial WMEG footprints in conjunction with the new footprints in Table 3. Each new footprint was added for a specific reason. Alt 2NV was designed to represent a more realistic scenario in which Bonneville is in EDAM while the Desert Southwest, which is unlikely to

[54] Bonneville Power Administration, Day-Ahead Markets *available at* https://www.bpa.gov/learn-and-participate/projects/day-ahead-market.
[55] *Id.*

join EDAM, is in Markets+. Alt 4A was designed to reflect utilities' market declarations and publicly stated leanings available at the time of the analysis. The Non-California West-wide Market footprint was added to see what west-wide benefits could be realized without the complexities presented in attempting to address CAISO's governance. These three additional footprints were used in various combinations with some of the above tasks, but not all additional footprints were tested for every task above.

Table 3 | Updated footprints for additional E3 studies

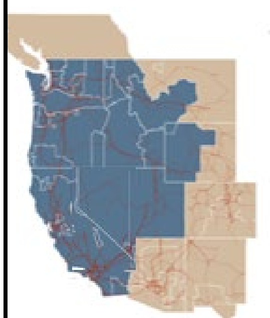
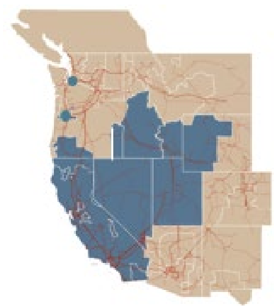
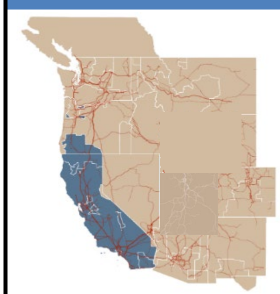
Alternative Split 2NV	Alternative Split 4A
 **EDAM:** California, PacifiCorp, NV Energy & all Pacific Northwest BAAs **Markets+:** BAAs located in the Desert Southwest and Rockies	 **EDAM**: California, PacifiCorp, NV Energy, Idaho Power, Portland General Electric, Seattle City Light **Markets+:** Rest of US WECC and British Columbia ***Reflects current day-ahead market declarations & leanings***
Non-CA Westwide Markets+	
 **EDAM:** California LSE's Only **Markets+:** Rest of US WECC and British Columbia	

Table 4 | Supplemental PCM Case Results[56]

- Section 1 of the table shares the raw case results by category for each of the supplemental analysis cases supplied by E3.
- Section 2 calculates the delta for each category of each case against anchor point BAU.
- Section 3 calculates the delta for each category of each case against anchor point Alt Split 4A.
- Positive numbers are costs and negative numbers are benefits.
- Red dots indicate a cost increase between the case and the anchor point.
- Green dots indicate a benefit increase between the case and the anchor point.

Table 4 | E3 Supplemental PCM results | Δ Supplemental case vs BAU | Δ Supplemental case vs Alt Split 4A

Supplemental Analysis

	Cost/Benefit Category	BAU (2026)	T9 | Alt Split 4A (2026)	T2 | Alt Split 4A M2M (2026)	T2 | Alt Split 4A M2M2 (2026)	T2 | Alt Split 4A M2M3 (2026)	T2 | Main Split M2M (2026)	T2 | Main Split M2M2 (2026)	T2 | Main Split M2M3 (2026)	T3 | BAU Low Water (2026)	T3 | BAU Low Water & Stressesd Loads (2026)
E3 Supplemental PCM Results	Load Costs	921	739	818	874	910	961	981	983	1104	1132
	Gen Costs	131	131	131	131	131	131	131	131	131	131
	Gen Rev**	-1140	-835	-987	-1097	-1166	-1231	-1365	-1279	-1201	-1218
	Congestion Rev	-50	-65	-59	-56	-57	-52	-54	-57	-30	-30
	GhG Rev	0	0	0	0	0	-1	-1	-1	0	0
	Net Cost w/o Wheel	**-138**	**-30**	**-98**	**-148**	**-182**	**-192**	**-208**	**-222**	**4**	**15**
Δ BAU vs Supplemental Case	Δ BAU | Load Cost		-182	-103	-47	-11	40	60	62	183	211
	Δ BAU | Generation Rev		305	153	43	-26	-91	-125	-139	-61	-78
	Δ BAU | Congestion Rev		-15	-9	-6	-7	-2	-4	-7	20	20
	Δ BAU | GhG Rev		0	0	0	0	-1	-1	-1	0	0
	Δ BAU | Net Cost w/o Wheel		**108**	**41**	**-10**	**-44**	**-54**	**-69**	**-84**	**142**	**153**
Δ Alt Splits 4A vs Supplemental	Δ Alt 4A | Load Costs	182		79	136	171	222	242	245	366	393
	Δ Alt 4A | Gen Rev	-305		-152	-262	-331	-397	-430	-445	-366	-384
	Δ Alt 4A | Congestion Rev	15		6	9	8	13	11	8	35	35
	Δ Alt 4A | GhG Rev	0		0	0	0	0	0	0	0	0
	Δ Alt 4A | Net Cost w/o Whee	**-108**		**-67**	**-118**	**-152**	**-161**	**-177**	**-192**	**35**	**45**

	Cost/Benefit Category	T3 | Alt Split 4A Low Hydro (2026)	T3 | Alt Split 4a Low Hydro & Stressed Loads (2026)	T3 | EDAM Bookend Low Water (2026)	T3 | EDAM Bookend Low Water & Stressed Loads (2026)	T4 | Alt Split 4A BPA EIM ONLY (2026)	T4 | Alt Split 4A BPA EIM ONLY Low Hydro Stress Load (2026)	T4 | EDAM Bookend BPA EIM ONLY Low Hydro Stress Load (2026)	T5 | Alt Split 4A Straw (2026)	T5 | Hypothetical New Additional TX (2026)	T10 | Non-CA WestWide M+ (2026)	T11 | Alt Split 2NV (2026)
E3 Supplemental PCM Results	Load Costs	957	1001	1043	1067	908	1109	1018	780	811	890	873
	Gen Costs	131	131	131	131	131	131	131	131	131	131	131
	Gen Rev**	-1032	-1067	-1184	-1201	-1129	-1203	-1203	-1104	-977	-1182	-1156
	Congestion Rev	-39	-39	-39	-38	-69	-31	-31	-58	-88	-46	-44
	GhG Rev	-1	-1	0	0	0	0	0	0	0	0	0
	Net Cost w/o Wheel	**16**	**26**	**-50**	**-42**	**-160**	**5**	**14**	**-61**	**-123**	**-207**	**-195**
Δ BAU vs Supplemental Case	Δ BAU | Load Cost	36	80	122	146	-13	188	97	-141	-110	-31	-48
	Δ BAU | Generation Rev	108	73	-45	-62	11	-63	36	226	163	-42	-15
	Δ BAU | Congestion Rev	11	11	11	12	-19	19	19	-8	-38	4	6
	Δ BAU | GhG Rev	-1	-1	0	0	0	0	0	0	0	0	0
	Δ BAU | Net Cost w/o Wheel	**154**	**164**	**89**	**96**	**-22**	**143**	**152**	**78**	**15**	**-69**	**-57**
Δ Alt Splits 4A vs Supplemental	Δ Alt 4A | Load Costs	218	262	305	328	169	371	280	42	72	151	134
	Δ Alt 4A | Gen Rev	-198	-232	-350	-367	-294	-369	-270	-79	-142	-347	-320
	Δ Alt 4A | Congestion Rev	26	26	26	27	-4	34	34	7	-23	19	21
	Δ Alt 4A | GhG Rev	0	0	0	0	0	0	0	0	0	0	0
	Δ Alt 4A | Net Cost w/o Whee	**47**	**56**	**-19**	**-12**	**-129**	**36**	**44**	**-30**	**-92**	**-177**	**-165**

Green = Benefit Greater than anchor point   Red = Increased Cost than anchor point

**Generation Revenue has been reduced by 15% to reflect slice revenue reduction

Table 5 | Consolidated supplemental case results for Alt Split 4A, Alt Split 4A WEIM Only, Alt Split 2NV, Alt Split 4A M2M, Alt Split 4A M2M2, and Alt Split M2M3

[56] During the development and execution of the supplemental analysis, Bonneville and E3 identified an issue regarding the "Generation Revenue" category. The load values provided by Bonneville to E3 reflected the preference load that Bonneville serves. The Generation values supplied by Bonneville to E3 were reflective of all generation including generation applicable to the Slice product. Bonneville and E3 decided to apply a 15% reduction to Generation Revenue results in the supplemental analysis to ensure Generation Revenue reflected Bonneville's estimated share of generation. This reduction was discussed with all stakeholders the public workshop 9 on November 4, 2024.

	A	B	C	D	E	F	G
	BPA Day-Ahead Market →	Markets+	No DAM Market WEIM-Only	EDAM	Markets+	Markets+	Markets+
1		Alt Split 4A (2026)	Alt Split 4A BPA WEIM-Only (2026)	Alt Split 2NV (2026)	Alt Split 4A M2M (2026)	Alt Split 4A M2M2 (2026)	Alt Split 4A M2M3 (2026)
2	Cost/Benefit Category				Declining Hurdle Rates		
3	Load Costs	739	908	873	818	874	910
4	Gen Rev	-835	-1129	-1155	-987	-1097	-1166
5	Gen Costs	131	131	131	131	131	131
6	Congestion Rev	-65	-69	-44	-59	-56	-57
7	GhG Rev	0	0	0	0	0	0
8	**NC w/o Wheel**	**-30**	**-160**	**-196**	**-97**	**-148**	**-182**
9	Δ Alt 4A | Load Costs	--	169	134	79	136	171
10	Δ Alt 4a |Gen Rev	--	-294	-320	-152	-262	-331
11	Δ Alt 4A |Congestion Rev	--	-4	21	6	9	8
12	Δ Alt 4A | GhG Rev	--	0	0	0	0	0
13	**Δ Alt 4A |Net Cost w/o Wheel**	**--**	**-130**	**-166**	**-67**	**-118**	**-152**
14	**Δ Alt 4A M2M's vs Alt Split 4A WEIM-Only Net Cost w/o Wheel**	--	--	--	**63**	**12**	**-22**
15	**Δ Alt 4A M2M's vs Alt Split 2NV Net Cost w/o Wheel**	--	--	--	**99**	**48**	**14**

These PCM cases were the most stakeholder-cited cases in responses to the Draft Policy.

Supplemental Case Results[57]

On the next page, Bonneville discusses the results from the supplemental analyses. In each case, the figures show raw case results and do not reflect differences against any other study case, though the original BAU result is plotted for reference. Negative numbers represent forecasted benefit, and positive numbers represent forecasted costs.

Figure 2 | All Supplemental Case Results

Figure 2 plots each of the supplemental case results together on a single chart. 2026 case results are depicted with circles, 2030 case results are depicted with triangles, and 2035 case results are depicted as diamonds. Yellow and orange denote dry water years and dry water years accompanied by stressed loads. Purple shades denote modifications to hurdle rates in the model.

[57] Energy and Environmental Economics, BPA WMEG Follow-up Analysis presentation (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf.

Figure 2 | E3 PCM results

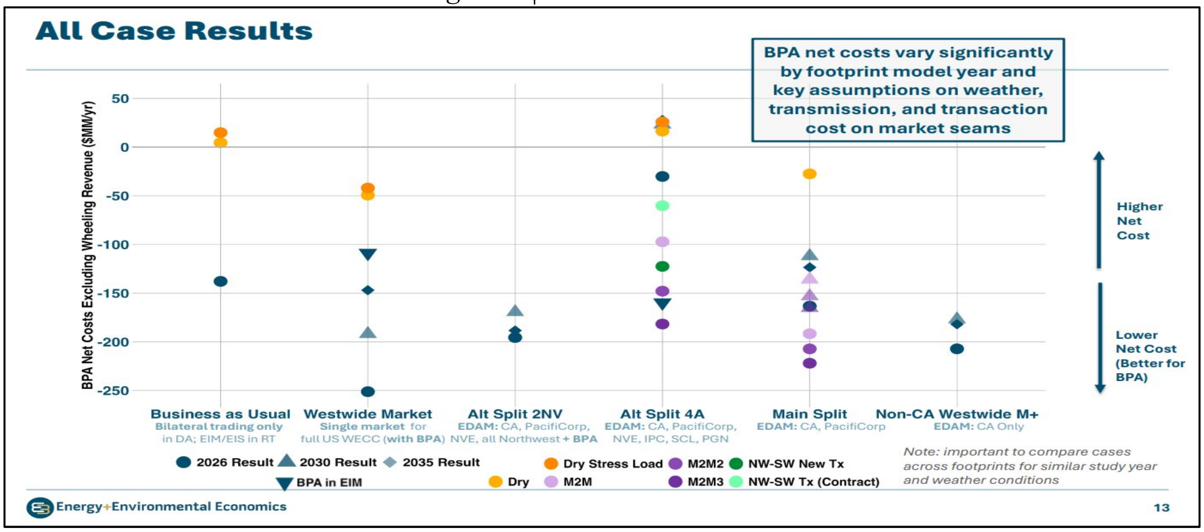


***Figure 2 Takeaway*:** Range of possible outcomes depending on various factors.

This graph shows the comparative impact of individual variables against each other. The graph illustrates an array of potential outcomes impacted by footprint composition, transmission connectivity, and other tested sensitivities. While Figure 2 plots all supplemental case results, not all case results are discussed in detail in the following sections. West-wide Market, Main Split, and Non-CA West-wide M+ are not feasible footprints due to market participation declarations already issued by BAAs.

Figure 3 | 2026 Base Footprint Results

Figure 3 plots 2026 supplemental case results including the new footprints as defined above plotted against some of the original WMEG footprints. We see that both the Alt Split 2NV case and the Non-California West-wide Market result in benefits above the BAU case, whereas Alt Split 4A results in benefits less than the BAU case.

Figure 3 | E3's 2026 Results

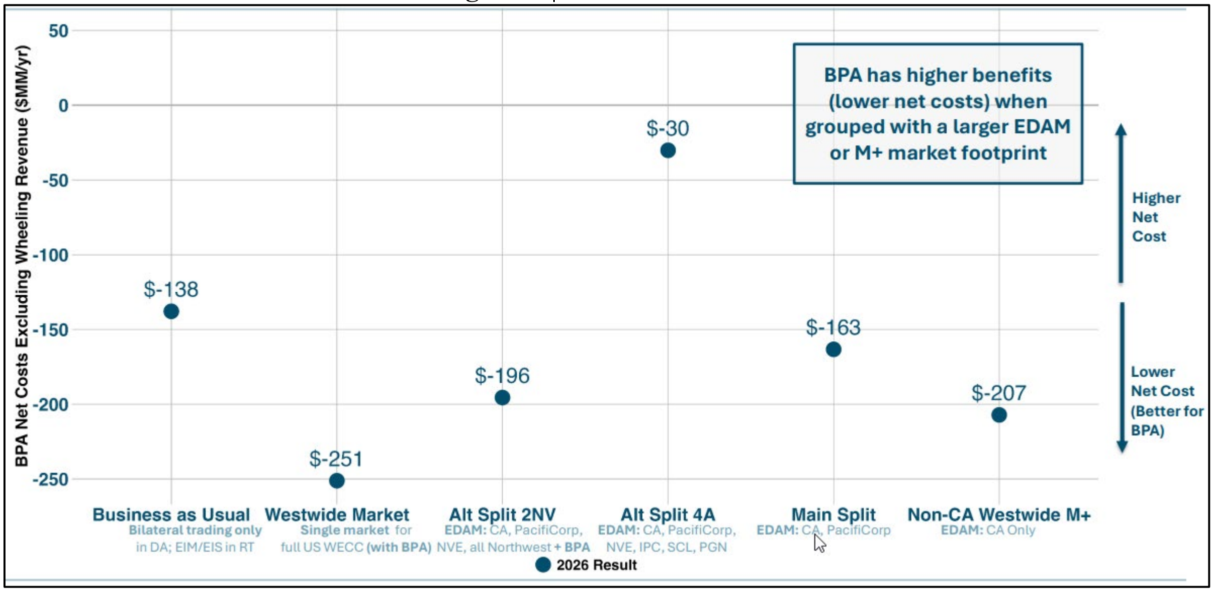


Table 6 | Alt Split 4A vs BAU

	N	O	R
1			
2	Cost/Benefit Category	BAU (2026)	T9 | Alt Split 4A (2026)
3	Load Costs	921	739
4	Gen Costs	131	131
5	Gen Rev	-1140	-835
6	Congestion Rev	-50	-65
7	GhG Rev	0	0
8	**Net Cost w/o Wheel**	**-138**	**-30**
9			
10	Δ BAU | Load Cost		-182
11	Δ BAU | Generation Rev		305
12	Δ BAU | Congestion Rev		-15
13	Δ BAU | GhG Rev		0
14	**Δ BAU | Δ Net Cost w/o Wheel**		**108**

Table 7 | Alt Split 2NV vs BAU

	N	O	AK
1			Supplemental
2	Cost/Benefit Category	BAU (2026)	T11 | Alt Split 2NV (2026)
3	Load Costs	921	873
4	Gen Costs	131	131
5	Gen Rev	-1140	-1155
6	Congestion Rev	-50	-44
7	GhG Rev	0	0
8	**Net Cost w/o Wheel**	**-138**	**-195**
9			
10	Δ BAU | Load Cost		-48
11	Δ BAU | Generation Rev		-15
12	Δ BAU | Congestion Rev		6
13	Δ BAU | GhG Rev		0
14	**Δ BAU | Δ Net Cost w/o Wheel**		**-57**

<u>*Figure 3 Takeaway*: Footprint is a primary driver of results.</u>

As discussed previously, the PCM results are highly dependent on the market footprint. Because Bonneville is a net exporter in the generation input data provided, footprints with higher LMPs, particularly during times of surplus hydro, result in increases to generation revenue that outstrip the increases to load cost. We see this in the Alt Split 4A results, where load costs go down by $182 million (see cell R10), but generation revenues go down by more ($305 million, see cell R11). Alt Split 2NV seems to balance this impact. The results show a smaller decrease to load costs than Alt Split 4A ($48 million, see cell AK10), but an increase to generation revenue ($15 million, see cell AK11). This is likely due to the timing of price fluctuations.

It is not possible to predict with absolute certainty which footprint will ultimately materialize. As seen in Figure 2 and Table 2, the initial and supplemental PCM analyses resulted in a range of cost or benefit outcomes. Given that there are two day-ahead market options in the region, both with substantial support from various entities across the West, Bonneville determined that it is best to look at the results for footprints with multiple markets. Based upon the information and the modeled footprints available, Bonneville sees Alt Split 4A (see Table 6) as the most realistic footprint with Bonneville in Markets+ and Alt Split 2NV (see Table 7) as the most realistic footprint with Bonneville in EDAM.

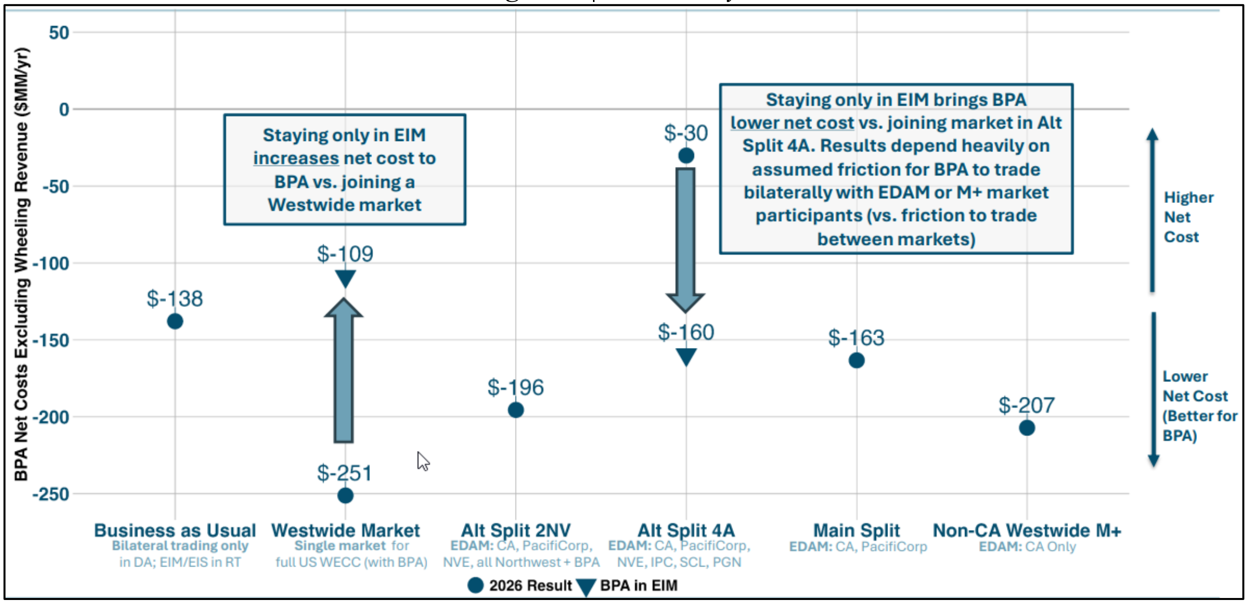
Alt Split 4A is a two-market scenario that divides participation between EDAM and Markets+. Geographically, Markets+ is divided into two regional areas. The first being the Pacific Northwest and the second being the Desert Southwest. EDAM participants are forecasted to lie between these two regional areas, creating a geographic division. The Net Cost without Wheeling Revenue forecast is an annual benefit of $30 million (as noted in Table 2 T9 – Alt Split 4A 2026), which is a decrease from the BAU case. The decline in benefit appears to be driven by a notable drop in Generation Revenue. Interestingly, this case also forecasts significant savings in Load Cost. Both the Generation Revenue decline and Load Cost savings are the product of lower locational marginal prices in Markets+ (relative to BAU). This footprint demonstrates the dichotomy between seeking the lowest cost to serve load and seeking to maximize value for surplus generation. Bonneville must weigh the challenges of seeking the greatest revenue value for surplus generation, while recognizing that customers may also benefit from the lowest costs to serve load.

Alt Split 2NV is a two-market scenario in which Bonneville, the Pacific Northwest, California, Nevada, and PacifiCorp's service territory are depicted as EDAM participants. Entities located in the Desert Southwest are modeled as Markets+ participants. This footprint creates geographical division, but, unlike in Alt Split 4A, each market maintains contiguous transmission connectivity. The Net Cost without Wheeling Revenue forecasts a benefit of nearly $200 million. When compared to BAU, Alt Split 2NV forecasts to be nearly $60 million better. Examining the categorical differences between cases shows that $48 million in Load Cost savings is driving the forecasted benefit.

Figure 4 | Base Footprint Results & WEIM-Only Results

Figure 4 plots 2026 supplemental case results and layers on the two WEIM-only scenarios that were modeled. In the WEIM-only cases, Bonneville remains outside day-ahead markets while continuing to be a WEIM participant, and the other entities in WECC participate in the day-ahead market in varying footprints. The WEIM-only option was evaluated for the West-wide Market footprint and Alt Split 4A footprint. (Note that Bonneville had not yet developed the Alt Split 2NV footprint for use in this task, so it was not modeled.) The arrows indicate the change in benefit to Bonneville of remaining a non-day-ahead market participant in the respective cases. Specifically, benefits for the West-wide market footprint decline from $251 million to $109 million. Conversely, Alt Split 4A sees an increase in benefit from $30 million to $160 million should Bonneville remain solely a WEIM participant. These are raw case results and do not reflect differences against any other study case.

Figure 4 | WEIM-only scenario



***<u>Figure 4 Takeaway</u>*: <u>WEIM-only benefits appear positive but the analysis does not consider long-term viability questions.</u>**

The results suggest Bonneville achieves benefit remaining outside of a day-ahead market, depending on the footprint. Compared to BAU, Bonneville would achieve benefits slightly greater than those in the current bilateral world if the Alt Split 4A footprint otherwise materializes. Comparing this WEIM-only case to that of Bonneville participating in Markets+ suggests that Bonneville achieves greater benefit by staying out of a day-ahead market. Alternatively, if the West-wide Market footprint materializes and Bonneville remains WEIM-only, Bonneville is modeled to see less benefit than being in EDAM and less benefit than BAU. However, these results cannot be viewed in a vacuum. Bonneville stresses that a significant limitation in these results is the assumption of a simple hurdle rate to access either market, which does not reflect the potential for decreased liquidity in the bilateral markets or increased friction to access either market as those markets grow. In addition, the reduction in access to trading partners may significantly degrade these results and make remaining a WEIM-only participant an unsustainable option in the long term.

Figure 5 | Base Footprint Results & Changing Hurdle Rates

Figure 5 plots 2026 supplemental case results testing multiple sensitivities of market-to-market (M2M) hurdle rates. The hurdle rates cases are noted in shades of purple (with lighter color representing a higher hurdle rate and darker color representing a lower hurdle rate) and were applied to Alt Split 4A and the Main Split footprints. The arrows indicate change in benefit for the respective cases. Both footprints demonstrate increased benefit as the hurdle rates are lowered. These are raw case results and do not reflect differences against any other study case.

As a reminder, hurdle rates are costs affiliated with transacting from one market to another. If no hurdle rate existed in the model, the market dispatch results would effectively be co-optimized results (like a single market footprint). This case study proposed to progressively lower the market-to-market hurdle rates with each new sensitivity. This was simulated through adjustment to transmission costs.

Table 8 | Hurdle Rate Descriptions & Value for M2M Cases

Hurdle Rates - Markets+ Footprint Exports						
WMEG	Supplemental Analysis					
	M2M		M2M2		M2M3	
Weighted Average OATT Rate of Market + Friction + Congestion Risk	DA	Weighted Average OATT +$6 adder	DA	Weighted Average OATT + $3 adder	DA	50% of Weighted Average OATT + $3 adder
	M2M DA = $10.50/MWh		M2M2 DA = $7.50/MWh		M2M3 DA = $5.25/MWh	
	RT	Weighted Average OATT + $3 adder	RT	Weighted Average OATT + $3 adder	RT	50% of Weighted Average OATT + $3 adder
$14.50 /MWh in DA & RT	M2M RT = $7.50/MWh		M2M2 RT = $7.50/MWh		M2M3 DA = $5.25/MWh	

**** Adder encompasses value for Friction & Congestion Risk***

Figure 5 | Hurdle Rate Sensitivities

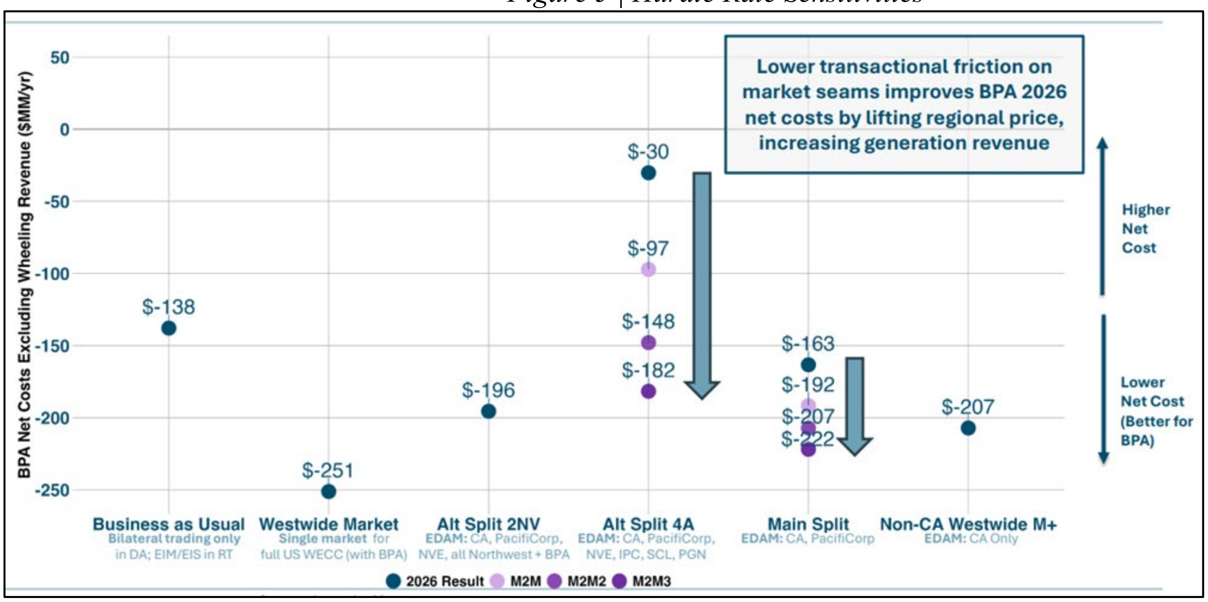


***Figure 5 Take-away*: Hurdle rates drive differences in footprint benefits; Bonneville can achieve benefits above BAU, including with the current expected Markets+ footprint.**

In both footprints tested, Bonneville's results improve with each reduction in the hurdle rate. For the Alt Split4A footprint, all three sensitivities forecast benefits for Bonneville. Two of the three cases forecast benefits greater than BAU. This suggests that Bonneville can achieve incremental net benefits in Markets+ in the Alt Split 4A footprint if it can still access EDAM with minimal friction, and that Bonneville would benefit from working to minimize that friction with both market operators. FERC recently noted that while seams are sure to materialize the market operators, BAAs, and stakeholders should coordinate to develop solutions that minimize friction at the seams. Bonneville concludes that lower hurdle rates are more likely than those initially modeled in the WMEG studies, providing better information that participating in Markets+ participation will result in benefits above business-as-usual.

Figure 6 | Base Footprint Results & Changing Timeline

Figure 6 plots 2026 supplemental case results and layers on future year scenarios which include augmentation of load, generation, and transmission (but do not include any changes to market design). Results for 2030 are plotted with triangles and results for 2035 are plotted with diamonds.

Figure 6: Cases over time 2026-2035

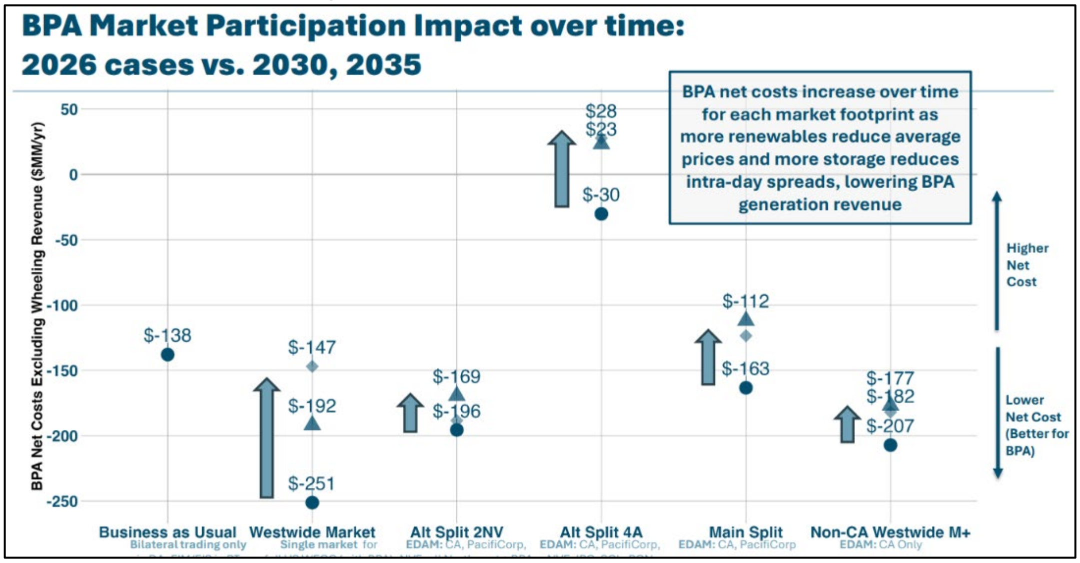


***Figure 6 Takeaway*: Changing regional resource mix may result in declining benefits over time.**

The supplemental PCM analysis also produced study case results for future years of 2030 and 2035. An interesting trend emerged when comparing the case study footprints from 2026 to 2035. In each footprint tested, forecasted Net Costs increase for Bonneville. As time progresses, benefits continue to decline. E3 identified this trend as the result of continued renewable resource participation and the expansion of storage resources. These resource additions result in reduced intra-day price spreads, limiting the value of shapeable hydro. Bonneville would see increased competition from those additional resources within the market and is unable to capture the same amount of Generation Revenue as depicted in early case results.

5.1.1.5. Concluding thoughts on PCM results

PCM results provide general direction (i.e., cost or benefit) and magnitude around market participation. The models offer an array of outcomes that are strongly impacted by the modelled footprint and hurdle rate.

Context for Magnitude of Benefits

To put these numbers in context, Bonneville's Fiscal Year 2026 Power Revenue Requirement is $3,451,708,000,[58] and provides the basis for recovering generation-related costs associated with the Federal Columbia River Power System (FCRPS), including the federal investment in hydro generation, fish and wildlife, conservation costs, non-federal power supply, and market purchases.[59] Bonneville's Fiscal Year 2026 Transmission Revenue Requirement is $1,626,696,000,[60] and provides the basis for rates to Federal Columbia River Transmission System (FCRTS) costs, including recovery of the federal investment in transmission and transmission-related assets, operations and

[58] Power Revenue Requirement Study Documentation - BP-26-E-BPA-02A Table 1A.
[59] Power Revenue Requirement Study - BP-26-E-BPA-02.
[60] Transmission Revenue Requirement Study Documentation - BP-26-E-BPA-09A TABLE 1-1.

maintenance and expenses associated with transmission and ancillary services.[61]

Bonneville's Power revenue uncertainty, largely driven by its power net secondary revenue uncertainty, has a standard deviation of approximately $250 million per year and a range of $2.2 billion.[62] This is not to diminish the significance of potential increased costs to Bonneville, but it is an important frame to place around the overarching strategic decision, the various other market design considerations, and the highlighted limitations of the PCM results. The general range of potential costs or benefits generated by Bonneville's PCM results of ~$150 million. This amounts to roughly +/- 3% of Bonneville's annual revenue requirement. This falls within Bonneville's range of Bonneville's net secondary revenue uncertainty.[63]

Participation in EDAM

Participation in EDAM produces the highest Net Cost benefit in the cases studied. However, examination of the sub-categories comprising the Net Cost illustrates that there are tradeoffs. Higher locational marginal prices drive up Generation Revenues in EDAM cases. The higher prices also result in greater cost to serve load. While Bonneville aims to maximize secondary revenue from surplus generation, it also aims to serve load at the lowest cost. Further, there is no guarantee Bonneville will continue to have significant surplus generation available to market, so the higher projected costs to serve load in EDAM may not always be offset by higher revenue associated with surplus.

Remaining a WEIM-only participant

Remaining a WEIM-only participant, which would require continued reliance on bilateral trading in all time-horizons prior to real-time, carries risks not easily reflected in the PCM. As discussed in section 2.3, staying outside a day-ahead market as other participants join presents risks to bilateral liquidity and introduces additional barriers to access trading partners.[64] Market participating entities are expected to focus on trading in their respective day-ahead markets and may be unwilling to or limited in the extent they can transact outside the market in the day-ahead time frame. Bonneville anticipates that convincing trading partners to trade bilaterally, instead of offering their resource to the market, may require a premium. This dynamic makes the longevity of remaining solely a WEIM participant unclear.

Participating in Markets+

Markets+ offers lower cost to serve load but also forecasts reduced Generation Revenue. Similar to participating in EDAM, there is tension created between the objectives of serving load at least cost and maximizing surplus revenue. The market hurdle rate sensitivity cases add further context, as they indicate that in the right conditions, Bonneville may achieve benefits greater than BAU.

Overall Takeaways

These PCM results provide good indicators of direction and magnitude regarding day-ahead market participation. However, these results should not be viewed with the expectation of achieving specific forecasted dollars. The PCM results are forecasts that can be influenced by other factors that may alter the projected outcome. For example, modifications to market design items such as Congestion Rent, Scarcity Pricing, or Locational Marginal Price

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[61] Transmission Revenue Requirement Study - BP-26-E-BPA-09A. BP-26-E-BP-05A.

[62] BP-26-E-BP-05-CC01, Power and Transmission Risk Study, at 89 Table 1: Rev Sim Net Revenue Statistics for FY 2026 through FY 2028; *see also* Transmission Revenue Requirement Study Documentation, BP-26-E-BP-05A.

[63] Power and Transmission Risk Study, BP-26-E-BPA-05-CC01, at Table 1 (RevSim Net Revenue).
Power and Transmission Risk Study, BP-26-E-BP-05-CC01, at 89, Table 1 (Rev Sim Net Revenue Statistics for FY 2026 through FY 2028); *see also* Transmission Revenue Requirement Study Documentation, BP-26-E-BP-05A.

[64] *See* WECC, Reliability Implications of Expanding the EIM to Include Day-Ahead Market Services: A Qualitative Assessment, *available at* https://www.westernenergyboard.org/wp-content/uploads/WECC-report-reliability-implications-of-expanding-EIM-to-include-day-ahead-market-services.pdf.

computation can impact benefits. PCM models also do not account for qualitative elements such as differences in market governance structure, nor do they account for the way in which governance structure can impact market design, which impacts quantitative outcomes.

Bonneville views the PCM results as one component of a much larger decision framework for day-ahead market participation. While the PCM results are useful, they alone do not lead to a direct conclusion about which market participation decision Bonneville should make. These PCM results must be used in conjunction with the principles that Bonneville has proposed to inform a day-ahead market decision. The market design aspects discussed in section 5.2 provide important considerations for the broader potential benefits of Markets+ participation.

As explained earlier, one limitation of PCM is that it does not account for impacts to various types of power and transmission customers. The next section discusses Bonneville's proposed direction to continue assessing economic impacts.

5.1.1.6. Business Line Economic Impacts

Day-ahead market growth in the region is expected to impact Bonneville's costs, revenues, trading activity, and net secondary revenue volatility. While Bonneville's decision around day-ahead market participation will affect these impacts, changes are expected to occur regardless of whether Bonneville pursues day-ahead market participation. Bonneville is unable to forecast the financial impact around rates, products, and the volatility for any option prior to issuing its day-ahead market Policy.[65] This is because the specifics needed to conduct financial analysis, such as final market design, footprint, seams agreements, etc. are not yet known. Inventory and market price risk represent key drivers of overall financial risk to Bonneville, which exist in both bilateral and organized markets.

Most of the quantitative economic analysis on day-ahead market options were performed by E3 using PCM that produce a cost-benefit analysis. This analysis provides insight into the potential economic effect of different day-ahead market footprint options and a high-level evaluation of the overall economic effect on Bonneville. While informative, it does not provide the full range of inputs needed for Bonneville's finance models to show the full impact to setting and modeling rates nor the risk around those costs and revenues. Quantitative evaluation and modeling within both Power and Transmission Services also inform the range of financial impacts to both business lines, and to Bonneville as a whole. However, given what was modeled, Bonneville can understand some of the large drivers for costs and revenues.

5.1.1.7. Power Services

Joining a day-ahead market means that all resources and loads are served through the market clearing process. If customers or other utilities join a day-ahead market as their own market participant (Markets+) or Scheduling Coordinator (EDAM), they will bid and settle their own resources with the market and will have their load settled with the market operator directly. If a Bonneville customer is not a direct market participant, they will not be directly exposed to the day-ahead market settlements; instead, any financial impacts would be passed on through Bonneville rates.

In the context of what that means for cost-based rates, Bonneville will continue to conduct rate proceedings as described in Appendix A, and forecasted Net Secondary Revenue (NSR) will remain a meaningful component of calculating rates. The two main drivers of Bonneville's NSR forecasts in rates are Riverware modeling (forecasted hydro inventory) and Aurora modeling (forecasted energy prices). Aurora modeling results are frequently driven by price expectations for natural gas, and the fuel for frequent marginal resources in the modeling runs. These key drivers of NSR expectations will not be affected by Bonneville's decision to join a day-ahead market, as they will be subject to the same fundamentals regardless of day-ahead market participation. For example, the key drivers that influence prices, such as load demand, hydro inventory, and natural gas prices are fundamental conditions that will drive prices in bilateral markets as well as organized markets. Therefore, the forecasting of these drivers of NSR,

[65] See sections 5.1.1.6 and 5.1.1.7 below for a discussion of impacts to Power and Transmission customers.

which feed into rate proceedings, are not expected to change with a day-ahead market decision.

NSR represents a forecast of what Bonneville reasonably expects or targets for revenue outside of its long-term contract sales to preference customers (see section 6.7). In addition to continuing to provide long-term contracts, Bonneville expects that it will continue to conduct some level of bilateral forward transacting, however, frequency, volume, and terms may change with the evolution of markets within the region. Instead of bilateral trading in the day-ahead timeframe, Bonneville will see resources and loads cleared through the day-ahead market. As is the case today, actual NSR will deviate from rate case expectations, with the difference being reflected as an increase or decrease to Bonneville's financial reserves. Any financial impacts from day-ahead market participation will be a non-itemized portion of NSR to ensure consistency with the Bonneville objective of maximizing the value of its entire generation portfolio by optimizing across all market options.

The key area of difference introduced is that instead of bilateral transactions in the day-ahead timeframe, Bonneville will trade through the market, introducing financial settlements for resources and loads. In the same way that Bonneville must manage inventory and market price risk presented by regional fundamentals, Bonneville will continue to optimize the system through both commercial and operational actions, while minimizing risks. This will continue to be managed closely to minimize costs and maximize revenue for customers, as done today in the bilateral markets.

5.1.1.8. Transmission Services

The evolution of markets in the Pacific Northwest is ushering in day-ahead markets that will impact Bonneville as a BA and TSP. Just as the WEIM required Tariff, Rates, and Business Practice changes, the day-ahead market will require changes as well. This will affect both Network Integration Transmission Service (NITS) customers and Point-to-Point (PTP) transmission service customers. Bonneville needs to ensure that customers continue to receive reliable service. Bonneville's transmission customers rely on Bonneville for delivery of resources to load, whether in Bonneville's BAA or as a path to another BAA.

As Bonneville has seen two day-ahead markets developing, it has become reasonably certain that several of Bonneville's current transmission customers will be in BAAs that have joined a day-ahead market, even if Bonneville does not move to the same or any day-ahead market. Because Bonneville's transmission will be used in day-ahead, real time, and bilateral markets, Bonneville recognizes concerns about potential transmission cost shifts between these different markets. Bonneville will propose changes to its rates, tariff, and business practices to align cost impacts with cost-causation and ensure customers are informed to adjust their respective future business models as needed to account for the new market paradigm.

Both CAISO and SPP realize that day-ahead markets introduce a potential reduction of both short-term and long-term transmission revenues to participating TSPs.[66,67] This potential reduction results from the market design principle that all transmission of a participating TSP is available for the market to use, unless that transmission has been explicitly removed from the market's calculations. Because the market has access to all of the TSP's transmission, there is less incentive for entities to purchase transmission.

The E3 PCM analysis attempted to quantify the impact to transmission revenue, but Bonneville removed it from its PCM assessment.[68] Instead, Bonneville performed its own analysis on the potential impact that day-ahead market participation may have on its transmission revenue. Bonneville focused on PTP transmission because those customers mainly purchase PTP to wheel through Bonneville's BAA, while NITS customers mainly take service and remain in the Bonneville BAA. Bonneville assumed that sales of NITS transmission would remain the same.

[66] *Cal. Indep. Sys. Operator*, FERC Docket No. ER23-2686, Transmittal Letter at 22-23 (Aug. 23, 2023) ("CAISO EDAM Filing").
[67] *Sw. Power Pool*, FERC Docket No. ER24-1658, Transmittal Letter at 9-10 (Mar. 29, 2024).
[68] For more information on the removal of the "Wheeling Revenue" category from the PCM analysis, see section 5.1.1.2.3 above.

Bonneville estimated potential bookends for a potential decrease in transmission sales from $20 million to $200 million over time.[69] Fortunately, both Markets+ and EDAM have a mechanism to help the TSP recover some of the lost transmission revenues due to the day-ahead market; however, they are slightly different approaches.

Markets+ encourages transmission customers to retain and purchase long-term firm transmission rights through its congestion rent design that includes an allocation to transmission rights holders. This allocation allows a transmission customer to directly receive congestion rents if the customer holds firm PTP rights of monthly duration or longer or NITS rights (see section 5.2.4). The EDAM design does not provide the same direct allocation between OATT rights and congestion rents (see section 5.2.4), resulting in a less direct incentive for maintaining long-term transmission rights.

In addition to congestion rent, there are other incentives to maintain long-term firm transmission rights. These include transmission for load service, to meet the WRAP firm transmission requirement, and for interchange transactions importing, exporting, and wheeling through market footprints.

Furthermore, Bonneville has over 65 GW of long-term transmission service requests in its transmission queue, indicating significant demand that could mitigate potential losses of long-term firm sales. Although these customers can remove their requests, Bonneville has not experienced a reduction in its queue. If Bonneville did see a significant reduction of long-term revenues, Markets+ has a robust stakeholder process and governance model that would allow stakeholders to bring concerns up for review.

For the potential revenue loss associated with short-term transmission revenues, both the EDAM and Markets+ day-ahead market designs include a transmission revenue recovery mechanism allowing a participating TSP to recover the potential revenue loss resulting from releasing unsold available transfer capability (ATC) to the market. In Markets+, the Market Transmission Use (MTU) charge mitigates for short-term firm revenue losses, by allowing the TSP to recover the difference between its historical short-term revenue requirement and current short-term revenues.[70] The EDAM Access Charge provides a recovery mechanism for short-term revenue reductions, potential lost short-term revenues associated with future transmission capacity, and potential wheeling revenue shortfalls.[71] The MTU will be applied in the same manner for all TSPs in Markets+. The EDAM Access Charge, however, will be applied differently for CAISO than for other EDAM Entities because of differences in transmission service offerings.[72]

In summary, although participation in day-ahead markets may potentially reduce transmission revenues, both day-ahead market designs have mechanisms that help participating TSPs mitigate this impact. In addition, after entry into a day-ahead market, Bonneville will continue to monitor actual transmission revenue recovery and, if needed, advocate through the market stakeholder process for additional market design adjustments to mitigate any potential loss of transmission revenues.

5.1.2. Participation and Implementation Cost Estimates

Both EDAM and Markets+ have participation and implementation fees. Further, there would be implementation work associated with participation in either option. Cost estimates of each option are provided below. These are

[69] *See* Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation – Workshop 10 at 15 (Jan. 29-30, 2025), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/dam-workshop-10-presentation-20250129.pdf.

[70] SPP Markets+ Tariff, Attach. A § 7.11 (Market Transmission Use).

[71] CAISO EDAM Filing, Attach. A-2 (Clean Tariff) § 33.26.1 (EDAM Access Charges).

[72] For example, for potential wheeling revenue shortfalls "the EDAM transmission owner[] will be compensated for the transmission use that supports the excess wheeling at the EDAM transmission owner's non-firm hourly point-to-point transmission rate or the CAISO participating transmission owner will be compensated for excess wheeling through transmission use at the applicable wheeling access charge transmission rate." *Cal. Indep. Sys. Operator*, 187 FERC ¶ 61,154, at P 20 (2024).

based on Bonneville's BAA. Bonneville assessed implementation and participation costs from CAISO, SPP, and internal projections based upon the best available estimates in early 2025.

5.1.2.1. Market Operator Implementation Fee Estimates

EDAM Implementation Fees

CAISO's EDAM transmittal letter to FERC discusses implementation fees.[73] CAISO estimates the standard fee to be $1.2 million for each BAA that elects to join EDAM.[74] Fees can be larger due to the complexity and size of the joining entity, or if an entity seeks additional market simulation or parallel operations time.[75] CAISO projects typical implementation to take 18 months for each BAA. The timeline can be extended beyond 18 months to accommodate additional market simulation and parallel operations.

Bonneville is one of the largest transmission providers and BAAs in the Western Interconnection and expects a higher than standard implementation fee and a longer than average implementation timeline. If Bonneville were to elect to join EDAM, CAISO estimates the implementation fee to be between $2.5 million and $3 million, and the implementation time frame to be between eighteen and twenty-four months.[76]

Markets+ Implementation Fees

Based on Bonneville's proportional share among all likely funding participants, the estimated share of Phase 2 costs is approximately $26.8 million.[77] The implementation costs to join Markets+ are higher than those for EDAM because Markets+ will have its own software separate from SPP's other markets, whereas EDAM is an extension of the current CAISO day-ahead market, and WEIM and is implemented with the same software.

5.1.2.2. Ongoing Market Participation Fee Estimates

EDAM On-Going Fees

CAISO has annual operating fees to run the market. These fees cover the staff, tools, and applications needed for the market. These fees are collected through CAISO's Grid Management Charge (GMC). The GMC is charged to each EDAM transaction. Bonneville requested that CAISO provide a forecast of the annual GMC fees assuming that entities who have made declarations or provided market leanings are included in the EDAM footprint. CAISO projected that Bonneville could anticipate $29 million annually in GMC.

Markets+ On-Going Fees

Markets+ will also have an annual operating fee. This fee will cover staff, tools and applications needed to run and operate the market. The operating fee will be collected based upon the volume of transactions for each respective market participant. Bonneville contacted SPP to request a forecast of Bonneville's anticipated portion of these annual operating expenses. SPP estimated that Bonneville's expense could be between $13 and $15 million annually.

[73] CAISO EDAM Filing, Transmittal Letter at 105-07.
[74] CAISO, Extended Day-Ahead Market Final Proposal at 126 (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.
[75] CAISO EDAM Filing, Transmittal Letter at 105.
[76] *See* Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation - Workshop 10 presentation at 18-19 (Jan 29-30, 2025), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/dam-workshop-10-presentation-20250129.pdf.
[77] *Sw. Power Pool*, FERC Docket No. ER25-1372, SPP Markets+ Phase 2 Funding Agreement at 24 (Feb. 21, 2025).

Table 9 | Estimated Fees Paid to the Market Operator ($M)

Estimated Fees for Bonneville	**On-going Participation Fee (Paid to MO)***	**One-time Implementation Fee (Paid to MO)***
EDAM	~$29M /year	~$3M
Markets+	~$15M /year	~$26.8M
*BAA value/Bonneville share based on Load/Resource Activity		

Table 9 provides a summary of the on-going participation fees (based on footprints reflecting the current declarations and leanings) and the one-time implementation fees for EDAM and Markets+. While EDAM's implementation fee is quite low at $3 million, the recurring annual fee is double that of Markets+. The ongoing market participation fees above were provided by each respective market operator in early 2025. These are only preliminary estimates based on the information currently available. These estimates can be subject to change. The fees and cost allocations for each market may evolve as each market operator refines their annual market operating expense.

Bonneville has determined that the higher upfront Markets+ implementation fees are justified by the anticipated market benefits, including the superior design elements (discussed primarily in Section 5.2) and lower ongoing participation fees.

5.1.2.3. Internal Implementation Cost Estimates

Joining a day-ahead market would change the operations and systems for Bonneville across Power and Transmission Services. Bonneville performed an initial estimate of the costs to implement either day-ahead market. This assessment was separate from the E3 PCM cost-benefit analysis, which did not evaluate implementation costs. Any assignment of implementation costs to a particular business line will be done as part of an integrated program review process.

To develop the estimate for the implementation cost of joining a day-ahead market, Bonneville identified projects across the agency that would be required for implementation (e.g., metering, outage management, schedule submission, bid curve development, and settlements). The implementation cost of each project was then estimated based on the complexity in project execution. The cost estimate for each market is further broken into the non-labor and the labor components. The non-labor component reflects initial costs for software and hardware upgrades needed for supporting the technological or operational requirements for joining a day-ahead market, while the labor component reflects the incremental staffing costs. Non-labor costs are provided as a range to reflect the uncertainty around the ongoing EDAM and Markets+ design and development.

Bonneville's estimated implementation costs for EDAM and Markets+ are as follows in Table 10[78] :

Table 10 | Internal Implementation Costs ($M)

Market	**Non-Labor**	**Incremental Labor**	**Total Cost (Non-Labor + Incremental Labor)**
EDAM	$11.6M - $19.7M	$18.3M	$29.9M - $38M
Markets+	$26.8M - $47.3M	$26.9M	$53.7M - $74.2M

[78] CAISO's and SPP's one-time market implementation fees and annual operating fees are not included.

The estimated implementation cost for EDAM is about half of Markets+, as a large portion of Bonneville's existing infrastructure built for the WEIM could likely be used in EDAM. SPP has been developing Markets+ consistent with SPP's existing systems and processes, which are different than CAISO's and will require system modifications to enable Bonneville's market participation. Additionally, the higher estimate of the Markets+ implementation cost is also driven by an assumption that Bonneville may choose to switch Bonneville's Reliability Coordinator (RC) from CAISO RC West to SPP RC Services. While the RC change is included in the estimated costs for transparency, the change is not certain and would depend on future policy development.

5.2. Market Design Considerations

Bonneville has thoroughly evaluated various day-ahead market design elements and participated in the design development process for both EDAM and Markets+. While much of the design is similar between the two markets, there are several differences that Bonneville considers significant in its evaluation. These elements are discussed below.

5.2.1. Governance

Independent market governance continues to be paramount to Bonneville's Policy direction towards participation in Markets+. Bonneville defines its governance principle for market participation as "the market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders" and that "decision-making and stakeholder engagement occurs in a transparent and inclusive manner."[79] Joining a day-ahead market would represent a significant change to how Bonneville operates. The electric industry is grappling with complex issues, and there will surely be additional difficult issues and circumstances in years to come. While Bonneville can never eliminate all risk, Bonneville believes a governance model tailored to support collaborative, unbiased decisions on current and future issues will mitigate risk inherent to the evolution of the industry. It is not possible to quantify a dollar value for the attributes of independent governance, but substantial value comes through in the decision process for market design and Bonneville's ability to influence that design. As noted, current examples include, but are not limited to congestion revenue, fast start pricing and GHG accounting.

Through its public discussion of market participation and consideration of market platforms, Bonneville has heard near-consensus agreement that independent governance is a core principle for regional market design.[80] Bonneville's evaluation considers the relevant factors associated with governance structures under both Markets+ and EDAM to identify the best governance structure available for Bonneville's decision regarding day-ahead market participation. While entities may disagree about what level of governance is sufficiently independent, Bonneville wants the decision-making body for a market to be free of disproportionate obligation to the policies of a single state, entity or customer type. Ideally, management and operations of the market would be independent of any single state or participating entity. In the near term, at the management level, the staffing and process for decision development and stakeholder engagement should equitably weigh the policies or priorities of all states, entities, and customer classes. Finally, the market's design and policies should be equitable in its consideration of the approaches established by all states with participating entities. The following discussion explains the evaluation under each of these factors.

Independence of the decision-making body

In its consideration of EDAM and Markets+, Bonneville evaluated the independence of their respective decision-

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[79] Section 4.1.6 above.

[80] *See, e.g.*, Letter from Western State Utility Regulators to the Western Interstate Energy Board (July 14, 2023), *available at* https://www.westernenergyboard.org/wp-content/uploads/Letter-to-CREPC-WIEB-Regulators-Call-for-West-Wide-Market-Solution-7-14-23-1.pdf.

making bodies.

Today, governance for EDAM is entrusted to the CAISO Board of Governors. The Board has delegated certain authority to the Western Energy Markets (WEM) Governing Body, subject to the Board's oversight, in a model referred to as Joint Authority.[81] The CAISO Board of Governors is appointed by the Governor of California with the consent of the California State Senate. Board members oversee CAISO in both its role as the market operator and largest BAA in the market. Members of the WEM Governing Body are nominated from stakeholder sectors and approved by current members of the Governing Body. The Governing Body acts on recommendations developed under the CAISO stakeholder process, which is largely CAISO staff driven. CAISO utilizes working groups to develop the initial stages of policy initiatives then proposals are developed by staff with open comment opportunities for all stakeholders.

The Governor of California's selection of the CAISO Board of Governors risks undue influence of a single state over EDAM. In addition, California law establishing authority for the CAISO Board of Governors requires it to act in the interests of the people of California.[82] While these governance elements were reasonable for the original CAISO market that only operated within California, they are significant flaws in the governance of a regional market that includes participants in other states. These flaws require mitigation that is currently only proposed.

As addressed in Appendix B, a number of regional entities have acted in pursuit of this objective through Pathways,[83] which will be discussed in more detail. Pathways has continued development of proposals for a new entity with an independent governance structure that is capable of overseeing an expansive suite of West-wide wholesale electricity markets and related functions. In 2024, the CAISO Board of Governors and the WEM Governing Body jointly approved additional governance changes that were recommended from Step 1 of Pathways. These changes placed the sections of the CAISO Tariff for WEIM and EDAM under the primary authority of the independent WEM Governing Body. WEM Governing Body decisions will be reviewed by the CAISO Board of Governors on a consent agenda. If the Board disagrees with the Governing Body's decision or vice versa, CAISO will prepare and submit dual filings to FERC on behalf of each body. The CAISO Board of Governors may exercise sole authority for FERC filings in exigent circumstances. Critically, the day-to-day management of policy development and market operations remains with CAISO management who ultimately report to the CAISO Board of Governors. Additionally, the Board's considerations as a BA have the potential to influence its decisions as the market operator.

In contrast, Markets+ will be governed by the Markets+ Independent Panel (MIP).[84] MIP members must be independent of market participants. They are selected through a nomination process of the Markets+ Governance and Nomination Committee and confirmed by the Markets+ Executive Committee. One independent member of the SPP Board of Directors serves on the MIP. The SPP Board of Directors retains authority for specific financial oversight of Markets+. The independent board acts on recommendations developed through a transparent process involving all market participants and stakeholders. The participants and stakeholders collaborate in working groups that have proven effective to build consensus and, where consensus is elusive, to frame the different perspectives for the independent board's consideration in its decisions.

Markets+ decision-making will be under the authority of the MIP whose members, save one representative of the SPP Board, are selected by the Markets+ participants. Additionally, Markets+ is separate from the SPP RTO, so its only focus is on being a market operator. From this comparison, Bonneville finds that the independence of the

[81] *See* CAISO, Governance (2025), *available at* https://www.westerneim.com/Pages/Governance/default.aspx.
[82] Cal. Pub. Utils. Code § 345.5 (2025).
[83] *See* Western Interstate Energy Board, West-Wide Governance Pathways Initiative (2025), *available at* https://www.westernenergyboard.org/wwgpi/.
[84] SPP Markets+ Tariff, Attach. O (Markets+ Governance) § 4.2 (Markets+ Independent Panel). Pending initiation of operations as Markets+, this independent board role is exercised by the Interim Market Independent Panel (IMIP) of three members of the SPP Board. References to the ongoing role of the Markets+ independent governing board will be to the MIP.

Markets+ decision-making body is superior to that of the EDAM and is more likely to result in decisions that create a fair and equitable market that allows Bonneville to meet its load service, power marketing, and transmission obligations.

Decision development and stakeholder engagement

In Bonneville's experience, a market's structure for both stakeholder engagement and decision development are critical to ensuring fair and equitable decision outcomes. Bonneville places great weight on the supporting structure for market decision development through market operator staff and the roles of participants and stakeholders in policy development. This structure is critical to ensure that Bonneville's interests are heard and adequately addressed in the decision process. The difference is not theoretical; Bonneville has been an active participant in both EDAM and Markets+ stakeholder processes and has experienced the difference in terms of decision-making for agenda priorities, collaborative process, and consensus decisions.

Bonneville has observed that the Markets+ structure has a proven track record of effectiveness. Notably, the structure delivered the complete tariff design on an abbreviated schedule through 2023. The structure involved working groups and task forces of market participants and stakeholders who conducted their discussions in publicly noticed and accessible meetings. The structure uses "indicative voting" to document support and opposition from participating stakeholders individually and by sectors. The use of indicative voting promoted collaboration among participants and built confidence in the outcomes. A prime example of the success of the Markets+ governance structure is the development of a mechanism for GHG accounting that meets customer compliance obligations for multiple states and pricing approaches while not adversely affecting states without those obligations.

Bonneville proposed and obtained consideration of its statutory and contractual obligations through the Markets+ process. The working group processes are publicly accessible and consider perspectives from utilities, states, and independent organizations. Stakeholders themselves can set the agenda for issues to be considered by the Interim MIP (IMIP). SPP staff provide appropriate facilitation and technical support roles while respecting the decision-making roles of market participants. The Markets+ Executive Committee (MPEC) ultimately votes on decisions to be brought before the MIP, providing a final opportunity for input from the sectors. Decisions reflected negotiation and compromise, with the IMIP returning issues to the MPEC when insufficient consensus had been reached.

The Markets+ governance structure relies on the time and abilities of market participants and stakeholders to develop market design proposals and deliberate on recommendations. Bonneville acknowledges concerns about that level of commitment. From Bonneville's perspective, this time is well invested for the value of collaboration among participants, shared understanding of the issues and tradeoffs involved, and for durable outcomes. The experience to date has been demanding, to be certain. However, it has yielded unparalleled engagement in the complex challenge of establishing a market. As the market moves into implementation, the cadence of participant work should be more manageable and provide opportunities for entities to combine their efforts.

Bonneville has not experienced the same depth of balanced stakeholder consideration in the staff-driven CAISO engagement model. Bonneville acknowledges the knowledgeability of CAISO staff and CAISO's efforts to develop a more participatory stakeholder engagement process. Bonneville appreciates and respects the professionalism and expertise that CAISO staff routinely display in their stakeholder process. This process, however, could be enhanced through increased stakeholder leadership in policy and implementation development, evaluation, and decision processes. The CAISO governance model also continues to present challenges in resolving contentious regional issues. CAISO must navigate competing priorities for staff and management time on regional issues versus the demands for attention to its own BAA and participating transmission owners.

Bonneville concludes that the Markets+ decision development and stakeholder engagement process is the best approach to ensure a fair and equitable market across multiple states and fair consideration of Bonneville's objectives and obligations.

Reasonable harmonization of state policies

The influence of an individual state in market design can manifest in the obligation of the market to incorporate that state's regulatory or policy design as predetermined conditions. Bonneville, especially from its role as serving utility customers in seven states, seeks a governance model that fosters harmonizing differing state policies.

The structure of the Markets+ policy process supports treatment of different state policies on an equal basis. The policy development process invites market participants to bring their state compliance obligations to the market design and includes the active participation of state representatives. Bonneville observes that this structure has allowed consideration of different state policy designs to arrive at a high degree of consensus on designs that serve the goals of multiple states and the utilities that serve them.

By contrast, CAISO market design rests on a foundation of California state policies. In the design of a regional wholesale market, this approach carries forward to a choice that either California's policy design, for example in GHG accounting, must be accepted as the market standard, or that the market must develop and incorporate alternative designs for those participants outside California.

Bonneville determines that the equivalent consideration of state policies by the Markets+ governance design is superior to that of the EDAM. Currently, there are two FERC approved day-ahead market tariff options available to Bonneville but one—Markets+—is superior with respect to stakeholder engagement, decision-making, and overall market governance.

5.2.1.1. Impact of Pathways on Bonneville's -Day-Ahead Markets Decision

Bonneville has assessed the progress made by Pathways in evaluating its day-ahead market alternatives. Through the Pathways engagement, Bonneville has supported the option for creation of an independent entity with independent administration and operation. While Pathways has made progress in advancing the governance of the WEIM and EDAM, the initial structure proposed in the Step 2 final proposal does not meet Bonneville's standards for independent governance as discussed in detail in Appendix B. The proposed approach is also dependent on legislation successfully passing in California to enable the Regional Organization (RO) structure as proposed, and allowing expansion to greater independence as described in the Step 2 proposal. California Senate Bill540 seeks to enable the Pathways Step 2 recommendation. The legislation would authorize the CAISO and California investor-owned utilities to participate in voluntary energy markets governed by an independent regional organization. Proposed legislation responds to a delicate balance between the interests of parties outside of California, including Bonneville, that the independent regional organization be wholly separated from undue influence of California state government; and the interests of parties in California that the regional organization support California energy and environmental policies. To achieve this balance, the current legislation seeks to reassure California that there are adequate safeguards for respecting California policies through providing for rights of withdrawal as ordered by the California Public Utilities Commission (CPUC). The proposed legislation provides that the CPUC may order California IOUs to withdraw in response to market rules or operations that it deems "detrimental to California consumers or California procurement, environmental, reliability, or other public interest policies." While presented as a "savings" provisions representing current CPUC authority, this scope of authority is made explicit by the proposed legislation. In continuing legislative committee discussions, the bill author and legislators have discussed adding more "guardrails" to ensure market respect for a broad list of California policies and adding requirements for additional legislative review of the RO structure and functions. In emphasizing these authorities as a means of reassuring California policy leaders, it causes reasonable and substantial concern for entities outside of California. Entities outside of California, including Bonneville, will be in a difficult negotiating position within the regional organization governance structure when any proposed rule or business practices can be referred to the CPUC or Legislature for a determination that the proposal will be "detrimental" to a broad and general set of policies. The legislation does leave available improvements in the stakeholder process and market design process to make it more equitable for parties inside and outside of California. Nevertheless, Bonneville is concerned that the legislation as drafted may not meet Bonneville's governance requirement. At the time of this Policy direction, uncertainty remains regarding whether 5B 540 will ultimately be passed and, if so, in what form.

5.2.2. Resource Adequacy and Resource Sufficiency

As discussed in section 4.1.3, a primary aspect of reliability impacted by market design is resource sufficiency and by extension, RA. RA generally refers to long-term planning and procurement of resources to serve expected peak or critical load in a year or season. Resource sufficiency generally refers to procurement of enough resources to serve expected load in the short term (e.g., moving into the week/day/hour). In considering generation and transmission, RA aims to have enough physical resources (e.g., long term expected generation output, new generation or transmission construction) to serve a forecasted peak load well into the future (often many months or years), while resource sufficiency considers the current operational landscape (e.g., outages or derates, up-to-date variable generation and load forecasts, etc.). The two concepts work in concert and are both vital to minimizing scarcity, emergency, or loss-of-load events. The market operator does not take on the role of LRE in either day-ahead market option.[85] All day-ahead market participants are still responsible for their adequacy and sufficiency, and thus obligated to enter the day-ahead market timeframe with a resource portfolio (including power purchases) that can meet their expected load.

Markets+ contains both an RA and resource sufficiency requirement. As a prerequisite to joining Markets+, entities that are LREs must participate in WRAP.[86] WRAP is a regional RA program that increases transparency into the resources and transmission needed to reliably supply power to meet a participant's existing and future load demands. Participation in WRAP requires consistent planning from all participants (which is measured using common RA metrics applied consistently to all participants), to help prevent any entity from leaning on the power supplies of others. Current WRAP participants include most utilities within the Western Interconnection outside the state of California.[87] For long- and short-term planning, the WRAP Forward Showing program requires entities to demonstrate that they have the available generation capacity needed to meet its forecasted peak P50 obligations plus an established planning reserve margin, and 75% of the transmission (as firm transmission) needed to bring generation to load.[88] While Markets+ participation is not required to be a WRAP member, Markets+ is the only day-ahead market choice in the West that requires participants to be in a common RA program, in this case, WRAP.

WRAP feeds into Markets+ via the market's day-ahead and real-time Must Offer Obligations. The Must Offer Obligations require all entities to bring at least the amount of generation needed to meet their forecasted load. If an entity fails to meet its Must Offer Obligation, that entity is financially penalized to discourage failures in the future, but physical market transfers and the optimization of the market footprint are not impacted. This simplified approach is supported by the Markets+ common RA metrics provided by universal WRAP participation because market participants are not only checked for day ahead and real-time sufficiency, but are also assessed for RA much farther out than real time. The inclusion of WRAP and the potential charges for failure to be resource adequate disincentivizes utilities who do not have adequate resources from leaning on other market participants in order to serve load in a manner that is stronger than the EDAM design, which, as explained below, relies only on penalties in the operational timeframe.

The EDAM design does not propose a uniform RA metric nor require EDAM entities to participate in an RA program. EDAM does leverage a Resource Sufficiency Evaluation (RSE) to ensure its footprint is adequate heading into the day-ahead and real time operating periods. EDAM's design leverages the WEIM design which calls for the limiting of an entity's BAA-BAA market transfers for entities that ultimately fail the real time RSE unless entities elect to accept

[85] A Load Responsible Entity (LRE) is an entity directly responsible for ensuring an electrical load is served.

[86] SPP Markets+ Tariff, Attach. A § 5.1.1; *id.* Appendix 3 (Attestation Regarding RA and Participation in WRAP).

[87] Western Power Pool, WRAP Participant Map (last mod. Dec. 30, 2024), *available at* https://www.westernpowerpool.org/news/wrap-area-map.

[88] Western Power Pool, WRAP Tariff § 16.3 (FS Transmission Requirement), *available at* https://www.westernpowerpool.org/private-media/documents/WRAP_Tariff_Effective_1.27.25.pdf ("The FS Transmission Requirement must be met with NERC Priority 6 or NERC Priority 7 firm point-to-point transmission service or network integration transmission service, from such Participant's Qualifying Resource(s) or from the delivery points for the resources identified for its Net Contract QCC or for its RA Transfer to such Participant's load.").

energy transfers through Assistance Energy Transfers, which include an associated penalty charge.[89]

The Markets+ Must Offer Obligation and the EDAM RSE serve a similar purpose, which is to evaluate whether each entity has procured enough resources to support its anticipated demand for the coming day, but the Markets+ integration of WRAP helps ensure equal and prudent planning and resource acquisition in the longer term. By leveraging the WRAP Forward Showing Program through its day-ahead and real-time Must Offer Obligations, Markets+ standardizes, simplifies, and solidifies each market participant's requirements to bring sufficient resources to the market to serve its loads. The more simplified resource sufficiency tests that Markets+ employs in the day-ahead and real-time also have the potential to provide benefits to Bonneville and other Markets+ participants. WRAP participation and the Markets+ Must Offer Obligations ensure sufficiency in a manner that sends strong financial signals that disincentivize future failure to bring sufficient capacity to the market and compensate those who make up any shortage, while still allowing all entities, and the market as a whole, to maintain a reliable, optimized footprint.[90]

While some California utilities are subject to RA requirements under the CPUC jurisdiction, these metrics may be different than those used in WRAP. Further, EDAM participants outside of California may be participants in WRAP, but they are not required by the EDAM market to participate in any RA program. EDAM's lack of common RA metrics makes it difficult to assess whether the footprint as a whole will be resource adequate in the planning horizon. While the EDAM RSEs are intended to prevent market participants from leaning on other market participants by failing to provide sufficient resources to meet their own loads absent market optimization, there are limited options in the day-ahead timeframe for addressing footprint wide sufficiency issues. A lack of a common RA program leaves the task of disincentivizing leaning solely to the EDAM RSE. Limiting transfers for entities that fail the real time RSE is suboptimal for all market participants, and the AET rate alone does not provide as robust an incentive for participants to maintain resource adequacy or resource sufficiency as the design of Markest+.[91] As long as EDAM entities find it more economical or convenient to pay the AET, they can lean on other EDAM entities as a substitute for effective long-term planning to meet their load obligations. The combination of both WRAP charges and the Must Offer Obligation makes such a determination less likely in Markets+.

As concerns continue to grow about RA in the Western Interconnection,[92] the Markets+ design is objectively superior to EDAM because it combines a common long-term RA metric with short-term resource sufficiency obligations, ensuring adequate supply, reliability, and fair compensation. Therefore, Bonneville views Markets+ as the superior day-ahead market choice for supporting regional RA.

5.2.3. Price Formation and Market Power Mitigation

Appropriate price formation ensures that market rules provide appropriate price signals, which compensate resources at prices that reflect both the value the resources provide to the market and the operational conditions that drive the need to procure certain energy or capacity products. Price formation should also ensure that resources respond appropriately and accurately to dispatch instructions from the market. Key aspects of price formation[93] issues can include: uplift payments (including bid cost recovery which can undermine actionable price signals), offer caps and offer mitigation usage, scarcity pricing, fast start pricing, and operator actions (and any associated impacts, or lack thereof, on pricing).

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[89] CAISO, Extended day-ahead market resource sufficiency evaluation discussion at 8 (Oct. 21, 2022), *available at* https://www.caiso.com/Documents/ExtendedDay-AheadMarketResourceSufficiencyEvaluation-Presentation-Oct21_2022.pdf. CAISO, WEIM Resource Sufficiency Evaluation Enhancements – Phase 2 (November 7, 2022), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-ResourceSufficiencyEvaluationPhase2-Nov7_2022.pdf.

[90] SPP Markets+ Tariff, Attach. A §§ 5.1.1(C), 5.1.2(C).

[91] CAISO, Extended day-ahead market resource sufficiency evaluation discussion at 8.

[92] WECC, 2024 State of the Interconnection (Sept. 2024), *available at* https://feature.wecc.org/soti/index.html.

[93] For more information see FERC, Energy Price Formation (June 17, 2020), *available at* https://www.ferc.gov/industries-data/electric/electric-power-markets/energy-price-formation.

Related to price formation and necessary for a well-functioning electricity market, is the monitoring and mitigation of market power. The exercise of market power is when one or more entities reduce output below competitive levels so as to raise market-clearing prices.[94] Due to the nature of the deregulated electricity industry, with several large suppliers, who are regionally concentrated and loads with limited ability to exercise price sensitive demand, there is a possibility for the exercise of market power by certain entities. While organized markets are structured to encourage competitive and efficient outcomes through their formation, structural or behavioral issues may allow exercises of market power, which can be mitigated by design. Market power mitigation tests and rules, when effectively implemented, ensure that resources can bid their marginal costs, but are not able to exercise market power. Both market operators and market monitoring departments are committed to monitoring for and mitigating the exercise of market power, though they have different methodologies for assessing the market.

In EDAM, the Market Power Mitigation (MPM) assessment is an extension of the existing WEIM methodology, which looks to address structural market power in participating BAAs. BAA-level MPM uses a dynamic competitive path assessment to evaluate whether the available generation within the participating BAA can competitively meet its own demand without additional transfer imports. If the dynamic competitive path assessment conditions are deemed non-competitive, then all participating resources in the affected BAA are adjusted to the competitive locational marginal price or a lower value of their submitted bid or applicable Default Energy Bid (DEB).

Under the pivotal supplier assessment for MPM, large entities flowing on constrained paths are more likely to be considered a pivotal supplier and face price mitigation measures, by the nature of their structural location, leading to potential over-mitigation. Given the geographical structure of western BAAs, the mitigation assessment based on the pivotal supplier is determined on the participant's potential ability to exercise market power, rather than on the participant's observed behavior. Bonneville appreciates that CAISO is reviewing this aspect of the market design in its Price Formation Enhancements initiative.

In contrast, the Markets+ design leverages the conduct and impact framework for MPM which is used in other organized markets.[95] The conduct test evaluates whether a resource offer is significantly higher than the reference cost of energy, and the impact test determines whether that offer would significantly impact the market prices. If suppliers have been found to fail both conduct and impact tests, then mitigation measures can be applied. Under this framework, resource offers are actively assessed and a negative outcome to the market must occur in order to be considered an exercise of market power. Basing mitigation assessments on the perceived potential to exert market power, as EDAM does, particularly during times of scarcity, creates misaligned incentives and market signals which can prevent appropriate market outcomes. The Markets+ conduct and impact approach is more effective because it mitigates based on the exercise of observed market power, not the potential for market power, thus minimizing over mitigation.

In addition to the assessment for MPM, a key aspect of the market design is to ensure that the reference price calculation, the offer price used when a resource is mitigated, is appropriate. The methodology to determine the reference price for a mitigated offer curve will vary by resource type. For resources such as storage hydro, a key aspect is the opportunity costs associated with future generating periods. For storage hydro, the Markets+ and EDAM are very similar, as the Markets+ design was built upon the approach utilized in WEIM. Bonneville's internal opportunity cost estimation, a component of bid formulation, is dynamic and based on non-public information, making independent verification impossible, though both markets attempt to approximate Bonneville's

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[94] For more information see Scott Harvey and William Hogan, Market Power and Withholding (Dec. 20, 2001), *available at* https://scholar.harvard.edu/files/whogan/files/market_power_withholding_harvey-hogan_12-20-01.pdf.

[95] *See* SPP Markets+ Tariff, Attach. B (Market Power Mitigation Plan) & Attach. C (Market Monitoring Plan); *see also* SPP Markets+ Protocols § 11 (Market Monitoring and Mitigation), *available at* https://www.spp.org/Documents/73199/MarketsPlus%20Protocols%20-%20Combined%20-%20MPEC%20Approved%20as%20of%2020250131.pdf.

cost for mitigation purposes. Imperfect cost verification (conduct verification) further reinforces the important role of an impact test to reduce inappropriate over-mitigation.

In EDAM, CAISO employs the DEB model for hydroelectric resources. The DEB uses a formula to estimate the opportunity cost of hydro, focused on three main pricing components: a gas-price floor, short-term energy prices, and a long-term geographic floor. This approach specifically tailors the DEB of a participating resource to its geographic location. Markets+ stakeholders worked with SPP's Market Monitoring Unit to develop the Seasonal Hydroelectric Offer Curve (SHOC) framework. The SHOC is very similar to the DEB but also accounts for a hydro project or aggregation of projects' seasonal storage horizon as part of the opportunity cost calculation.[96] Both designs do their best to account for the flexibility of the system, allowing participants to preserve the value of hydro for future months when appropriate for their resource(s), helping other market participants benefit from the flexible nature of these resources. Bonneville prefers the Markets+ SHOC approach because it distinguishes between hydro resources with and without significant storage availability.

CAISO has undertaken stakeholder initiatives, such as the Day-Ahead Market Enhancements (DAME) and Price Formation Enhancements, to review and address changes to products and prices within its market. During its DAME[97] effort, CAISO created the Imbalance Reserve Product, which recognized the need to procure additional flexible products that can be economically awarded to help provide additional capacity and reduce out-of-market actions by the market operator. The CAISO/EDAM footprint had a demonstrated need for this product due to the uncertainty swings in the load-resource balance caused by the variable renewable resource mix within the footprint and the need for dispatchable resources that are deliverable and can ramp between fifteen-minute intervals[98]. While Bonneville was initially very supportive of this product, the final product design changed significantly in the final stages of the stakeholder process, at which point Bonneville identified a number of significant areas of concern, as did other stakeholders[99]. While Markets+ does not include a comparable product, WRAP includes financial incentives to ensure equitable procurement of capacity to prevent leaning on the capacity of others, as well as compensation for holdback and energy deployment. Bonneville accepted the position that developing a similar product in Markets+ without a demonstrated need could impose additional and unnecessary costs to load service and agreed to move the topic to the Markets+ "parking lot" for consideration after go-live. Bonneville will monitor its participation in Markets+ and consider whether it feels a similar product would be necessary and/or beneficial to the Markets+ design. Bonneville is confident that the Markets+ stakeholder process will address any concerns that arise.

In the Price Formation Enhancements initiative,[100] scarcity pricing and fast-start pricing are critical elements because they can ensure resources are appropriately incentivized and compensated for the attributes they bring to a market dispatch, while reducing the need for out-of-market actions. In addition to ensuring accurate prices in the short term, price formation can help send better price signals for developing supply to meet future demand. Transparent and equitable price formation is an important step toward increasing market efficiency through increased competition, potentially ensuring supplier cost recovery while reducing the cost load pays.

CAISO has mechanisms for implementing a level of scarcity pricing when the system is low on reserves and

[96] *See* SPP Markets+ Tariff, Attach. B (Market Power Mitigation Plan) & Attach. C (Market Monitoring Plan); *see also* Markets+ Protocols § 11.

[97] See the CAISO Day-Ahead Market Enhancements Initiative page for more details on these efforts and for Bonneville-submitted comments, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.

[98] *Id.*; *see also* CAISO, Day-Ahead Market Enhancements Stakeholder Technical Workshop presentation at 6 (June 20, 2019), *available for download at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.

[99] *See* CAISO, Day-Ahead Markets Enhancements Initiative (comments submitted by Western Power Trading Forum, Vistra, The Energy Authority, and Powerex) *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.

[100] *See id.*

network modeling needs to solve for tighter bid-supply conditions, but it does not currently have a design that includes compensation for fast-start pricing. Fast start pricing allows a generator's commitment costs, in addition to marginal fuel costs, to be considered in economic bid evaluation and directly captured in LMPs paid to all resources. CAISO is currently reviewing these topics as part of its Price Formation Enhancements initiative, in which Bonneville is actively engaged, although many stakeholders continue to oppose the adoption of fast start pricing. The absence of fast start pricing in CAISO reduces costs for California load by reducing fair and transparent compensation for generation in both California and throughout the West, including Bonneville's generation. In contrast, Markets+ incorporates fast-start as well as scarcity pricing into its day-ahead market design, which Bonneville believes helps to ensure accurate, fair compensation for all suppliers of flexible and reliable generation.

Bonneville's position on price formation and market power mitigation assessments has not changed from the April staff recommendation.[101] These are cornerstones of organized markets. Markets+ design elements ensure that resources can efficiently respond to market signals and be appropriately compensated, while avoiding over mitigation and ensuring transparent market pricing. Therefore, Markets+ design is more aligned with Bonneville's perspective regarding MPM and price formation, which can help improve outcomes for both resources and loads.

5.2.4. Congestion Modeling and Congestion Rent

Generally, the overall transmission design between EDAM and Markets+ is similar. Both day-ahead market frameworks rely upon transmission made available by market participants, TSPs, and transmission customers to facilitate the transfer of energy across the market footprint.[102] Market participants and participating TSPs in EDAM and Markets+ must make their transmission available for market use as a condition of participation, unless specifically opted out according to the respective market's rules. The CAISO EDAM Tariff allows participating entities to let transmission customers designate any of the transmission rights they hold as non-participating. The EDAM design intends for the EDAM Entity to make the ultimate decision to enable this market feature in its BAA.[103] The SPP Markets+ Tariff includes the opt-out of transmission from the market as part of the market design and has already established a communication process to opt-out transmission. In addition, both markets are designed to recognize market participants' existing transmission rights that can still be exercised in the day-ahead and real-time horizons. This is further explained in Section 6.8.

Physical Congestion Modeling

Ultimately, both EDAM and Markets+ will model constraints and manage transmission similarly. From a BAA perspective, each market will have to ensure that each participating and adjacent BAA can continue to calculate its

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[101] Bonneville Power Administration, Staff Recommendation on Day-Ahead Market Participation (Apr. 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/02-day-ahead-market-attachment-1-staff-recommendation.pdf.

[102] SPP Markets+ Tariff, Attach. D (Markets+ Transmission) § 1.0 (General); CAISO EDAM Filing, Tariff Appendix B.33 (EDAM Transmission Service Provider Agreement (EDAMTSPA)).

[103] The CAISO EDAM tariff provides:

> **Transmission Not Available in the Day-Ahead Market**. If the CAISO is informed through the prospective EDAM Entity implementation process or by the EDAM Entity Scheduling Coordinator for the EDAM Transmission Service Provider that accommodation of incremental intra-day schedules in the Real-Time Market should be unavailable in the Day-Ahead Market according to the EDAM Transmission Service Provider tariff, the CAISO will accept a notification from the EDAM Entity Scheduling Coordinator associated with the EDAM Transmission Service Provider and will adjust Day-Ahead Market availability of the impacted transmission elements and the associated transmission service rights.

Cal. Indep. Sys. Operator Corp., FERC Docket No. ER23-2686, Transmittal Letter, Attach. A-2, Tariff § 33.18.3.3 (Aug. 23, 2023).

Net Scheduled Interchange (NSI), Net Actual Interchange, manage area control error (ACE)[104] in real-time, and perform After the Fact (ATF) energy accounting. Further, capacity or energy transfers from each BAA (EDAM and Markets+) must accurately account for Bonneville transmission rights that were used to facilitate the transfers. At times, these BAA-to-BAA rights and transfer accounting models in each market may end up being constrained and produce congestion revenue which will need to be allocated. Further, each market will also be able to model physical constraints (e.g., flowgates, paths, or lines). When the physical limit (or allocation of a physical limit) is reached in either the day-ahead or real-time, each market will attempt to honor the limit and potentially produce congestion revenue. Any congestion revenue would be allocated under the market tariff or under the participating BA's tariff in the case of EDAM, as described below.

Congestion Rent Allocation

Congestion rents[105] are payments to participants that occur within a market when the types of constraints described above become limiting (i.e., when congestion occurs). When congestion occurs at a constraint, the least-cost energy cannot be awarded to be delivered to all loads while respecting the constraint limits. The price to serve an incremental MW of load on either side of the constraint is different, resulting in different costs to serve demand in different locations.

To illustrate, a hypothetical generator clears at $25/MW and some portion of its output is serving load across a constraint. Due to congestion, it cannot send an incremental MW of energy across the congested element. Another resource offers $35/MW. The load will pay $35/MW rather than $25/MW because its incremental MWs are served by the other resource offering $35/MW. In this scenario, the market operator will have received more money than it distributed due to the congestion that caused price separation between LMPs.[106] The market operator must then allocate these congestion revenues in some manner to ensure that it remains revenue neutral. Methodologies for how a market allocates this congestion revenue vary, but generally the aim is to return it to the loads and to the transmission rights holders.

n most RTOs and ISOs, this allocation is effectuated by the conversion of physical OATT rights to Congestion Revenue Rights (CRRs) or similar path-specific financial rights, which can also be procured through auctions. However, neither Markets+ nor EDAM will rely on these financial instruments. Congestion rent is instead dictated by the respective market design and as applicable, the participating TSP OATT. The congestion rent designs and allocation methodologies for the proposed day-ahead markets are quite different.

EDAM breaks all congestion rents into two categories: congestion revenue and transfer revenue. In EDAM, congestion revenues are allocated to the BA where the binding constraint is modeled.[107] Transfer revenue is

[104] Area Control Error (ACE) is a real-time calculation performed by every BAA's Automatic Generation Control (AGC) system that indicates when something has changed and the BAA or interconnection is not balanced, such as: BAA load deviated from forecast, generator deviated from schedule, interchange deviated from schedule, or interconnection frequency deviated from schedule. ACE is measured in megawatts (MW).

[105] Congestion management includes all operational actions taken by grid/transmission operators to **proactively** and efficiently manage congestion, maintain the smooth flow of energy, and minimize the need to take operator actions in real-time. One aspect of congestion management is ensuring that a Market Operator honor the operational limits provided by TSPs and TOPs and that these operational limits are reflected in the market dispatch. Respecting these operational limits can result in price separation between loads, which results in congestion revenue or rent. Congestion revenue or rent is the money collected by the market operator due to the operational limitations that result in price separation between load and generation. Congestion rent is the term used in Markets+ and how we will refer to this topic generally. EDAM specifically differentiates between congestion revenue and transfer revenue as two components of the allocation of these congestion rents.

[106] To see a more detailed example of congestion, please see Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 7 presentation (June 3, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-7-presentation-060324.pdf.

[107] *See* CAISO EDAM Filing, Tariff § 33.11.1.2 (Congestion Revenue).

collected when the net EDAM Transfer scheduling limit is reached in the day-ahead market, representing price separation between neighboring BAs in EDAM.[108] The transfer revenue is allocated equally between the two BAs, unless there is an alternative commercial arrangement.[109] An EDAM transfer rights holder that makes capacity available to CAISO is eligible to receive transfer revenue and congestion revenue settlements through the Scheduling Coordinator.[110] The allocation of congestion revenue and transfer revenue collected by the EDAM entity will be suballocated according to that EDAM BAA's OATT. The suballocation of congestion rents is thus subject to the individual rules of the transmission service provider's Tariff. This can present undue complexity for customers by producing a wide set of outcomes depending on the tariff or tariffs to which a customer is subject.

A fundamental challenge Bonneville sees with the EDAM approach to congestion rent is the allocation being based on BAs, rather than a footprint-wide allocation which focuses on rights attributable to key constraints. A transaction occurring inside of EDAM, even a scheduled delivery that exists entirely within one BA, could be exposed to congestion that occurs elsewhere within the EDAM footprint. Per the EDAM design, the revenues of this transaction would be solely distributed to the BA where the congestion is binding. Due to the nature of physical flows, this could be a frequent occurrence. Without the means to recover revenue from congestion that may have occurred in a neighboring BAA, entities are presented with the potential to be exposed to congestion charges without the means to adequately hedge or recover revenue from the costs incurred by load. When the congestion revenue occurs within the BAA, there is no guarantee that the BA's OATT will allocate congestion by constraint within their BAA, presenting additional risk that loads will be exposed to costs and unable to recover offsetting congestion revenue.

Issues with the EDAM design and concerns regarding parallel flows became apparent when PacifiCorp filed its Tariff revisions with FERC to enable its participation in EDAM.[111] Protesters raised concerns that the EDAM design did not allow for "a sufficient congestion hedge to transmission customers exercising their transmission rights."[112] In response to these protests, CAISO initiated an expedited stakeholder initiative to address these concerns. CAISO's proposal is "to allocate parallel flow congestion revenues to the EDAM balancing area where these revenues accrue associated with the exercise of long-term firm and monthly firm Point-to-Point and Network Integration Transmission Service rights based on submitted day-ahead balanced source and sink self-schedules."[113] While this proposed change presents a better hedge than the current design, Bonneville's concerns regarding the BAA sub-allocation design and the lack of direct hedging by constraint remain. In addition, proposed tariff revisions of entities pursuing participation in EDAM require self-scheduling in order to receive congestion rent.[114] Incentivizing self-scheduling significantly reduces economic participation in the market and limits optimization benefits.

Markets+ takes a very different approach to the allocation of congestion rents. It does not differentiate between congestion occurring within BAAs or between BAAs, but rather it evaluates allocations across the entire footprint, specifically the rights associated with individual constraints. The allocation of eligible rights by physical constraint across the entire footprint, rather than allocating by BAA, mitigates the concerns with the EDAM design highlighted above. In Markets+, congestion rents associated with physical constraints are allocated directly and proportionally to the transmission rights holders of firm and conditional firm PTP transmission service, network integration

[108] *See id.* § 33.11.1.1 (Energy Transfer Revenue). This language allows for either a 50/50 allocation or another pre-existing commercial arrangement.
[109] *See id.*
[110] *See id.* § 33.18.4 (CAISO Transmission at EDAM Interties).
[111] *PacifiCorp*, FERC Docket No. ER-25-951-000.
[112] *Draft Final Proposal: EDAM Congestion Revenue Allocation* at 3 (April 16, 2025) (available at: https://stakeholdercenter.caiso.com/InitiativeDocuments/Draft-Final-Proposal-EDAM-Congestion-Revenue-Allocation-April-16-2025.pdf.
[113] *Id.* (parentheticals omitted).
[114] *Portland Gen. Elec.*, FERC Docket No. ER-25-1868-000, Transmittal Letter at 17 (April 3, 2025); *PacifiCorp*, FERC Docket No. ER-25-951-000, Transmittal Letter at 18-19 (Jan. 16, 2025).

transmission service, and legacy transmission service of monthly or longer service increments whose rights are associated with that physical path, who have not opted these rights out of Markets+.[115]

Under the Markets+ design, PTP eligibility will be based on the eligible transmission service request (TSR), while NITS eligibility is tied to an allocation cap based on the customers' monthly peak load and the allocation across paths is based on the designated network resources offered to serve their loads.[116] However, if NITS customers use secondary NITS service, the Markets+ design does not include secondary service in the direct congestion rent allocation. In these cases, there may be congestion revenue, but SPP will not allocate it directly to the Market Participant. SPP will allocate any undistributed congestion revenue to the TSP, and the TSP will allocate those revenues according to its tariff.[117] In addition, the congestion revenue design will be monitored by the Markets+ stakeholders, with an emphasis on ensuring equity between customer types, and evaluated for potential changes in the future that may result in updates to the Markets+ design if appropriate[118]. If participants require an allocation between two binding BAAs to be enabled, similar to what is done for transfer revenue in EDAM, the Markets+ Tariff allows for an allocation between binding BAAs.[119]

Based on an assessment of these two approaches, Bonneville believes that the Markets+ constraint-level congestion rent design is more robust because it better recognizes the topology of the market footprint and directly aligns with how Bonneville models and manages transmission constraints. For this reason, along with the concerns regarding the EDAM design methodology for allocation of congestion revenue, Bonneville strongly supports the congestion revenue allocation methodology of Markets+.

5.2.5. Greenhouse Gas Accounting

Bonneville is not subject to any state GHG programs in the region. However, it is important to many of Bonneville's customers to maintain the low-carbon attributes of the federal system. The market design for GHG accounting—how resources and their associated emissions are assigned to market participants—is critical to ensuring Bonneville's customers can continue to claim the low-carbon attributes of the federal system to comply with various state-mandated GHG programs or for their own utility purposes. This is a particularly challenging area because the various state GHG-reduction programs have created a patchwork of inconsistent policy goals and economic drivers across the West that can be challenging for utilities to navigate in wholesale power markets. EDAM and Markets+ meet the GHG accounting needs of states and participants in two ways.

First, a dispatch-based solution has been developed that supports state carbon pricing programs like California's cap-and-trade program and Washington's cap-and-invest program. The dispatch-based solutions incorporate a price on carbon for generation located in the state subject to the state program and electricity imports to the state. The market optimization selects resources to be attributed to serving load in the state based on the most economically efficient outcome for the market, including the carbon price for the applicable state.

Second, out-of-market (i.e., non-dispatched based) tracking and reporting mechanisms are being developed to support the needs of states and participants generally. This accounting supports a participant's ability to claim their owned and contracted resources for GHG reporting purposes. Bonneville considered how a day-ahead market GHG accounting design will impact Bonneville's customers across the region. Bonneville believes that a market design must address GHG accounting in a way that works fairly and equitably for all participants and states and does not

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[115] *See* SPP Markets+ Tariff, Attach. A § 7.16 (Congestion Rent Eligible Transmission Service Reservation Verification).
[116] *Id.* § 7.16 (Congestion Rent Eligible Transmission Service Reservation Verification).
[117] *Id.* § 9.2.15 (Day-Ahead Excess Congestion Rent Allocation Distribution Amount).
[118] This monitoring plan was approved as part of the MCRTF protocols. SPP, Markets+ Monitoring Metrics Congestion Rent (Aug. 14, 2024), *available at*: https://www.spp.org/Documents/72193/Congestion%20Rent%20Monitoring%20Approach%20Clean.docx.
[119] SPP Markets+ Tariff, Attach. A § 7.16 (Coordinated Interchange Scheduling Limits). Similar to the EDAM design, this language allows for either a 50/50 allocation or another mutually agreed upon ratio.

prioritize a single state's policy.

Generally, day-ahead markets can improve GHG accounting by providing greater transparency and granularity of dispatch data, providing more specific emissions information associated with serving load inside the market footprint.[120] In recent years, markets have needed to develop solutions for addressing GHG accounting to support state program requirements and individual participant needs. Where state programs have enacted a price on GHG emissions, the market needs a way to determine what is least-cost for the entire market and simultaneously least-cost for meeting load in a state with the pricing program. In addition, the market needs a method for assigning dispatch of specific resources (and their associated emissions) to specific loads to support the GHG reporting needs and emission reduction goals for states and individual utilities.

GHG accounting and reporting for organized markets is an actively evolving area with markets developing solutions to meet state program GHG requirements and state programs updating rules to adapt to market design. There are still uncertainties about how organized market GHG accounting will work with state GHG reporting, and additional uncertainties as to how this transpires into the GHG reporting provided to states for purchases from the federal system. While Bonneville cannot provide explicit details on what GHG reporting will look like for Bonneville's customers with participation in a day-ahead market, significant progress has been made related to GHG market design and related state GHG reporting in recent years and there is sufficient information available to describe and assess generally how the market design will work. The GHG market designs are described below.

There is currently insufficient information to determine if joining a day-ahead market will increase or decrease emissions attributed to federal power purchases from Bonneville. There are a number of unknown factors that are material to overall emissions impacts, including what resources are participating in the market, the market's GHG tracking and reporting rules combined with state-specific GHG reporting requirements, and changes in market behaviors of participants (e.g., shifts from use of traditional bilateral markets to organized markets). Nevertheless, there is enough information available for Bonneville to determine that the Markets+ design is superior to the EDAM design as described below.

5.2.5.1. GHG Accounting for Carbon Pricing Programs

EDAM and Markets+ have developed solutions that dispatch and attribute least-cost resources (including GHG costs) to load in a carbon pricing state to support the needs of states with carbon pricing programs, like California and Washington. The market operators aim to meet the needs of states and utilities subject to the carbon pricing program without negatively impacting states and utilities without such a program. However, in many cases, challenging trade-offs are inevitable because the market must balance the differing policies of states with respect to GHG reduction.

Bonneville believes that Markets+ GHG accounting design for carbon pricing programs achieves a reasonable approach to a market design that supports states with carbon pricing programs while not unfairly impacting states and entities not subject to carbon pricing. Conversely, Bonneville finds that CAISO's design falls short. As explained below, Bonneville anticipates CAISO's current design could have adverse financial impacts to Bonneville's customers and jeopardize customers' abilities to continue to report the low-carbon attributes of their power purchases from the federal system. There are two fundamental differences in design features that lead Bonneville to this conclusion.

5.2.5.1.1. Markets+ "Type 1A" attribution ensures attribution of federal system power contracted to utilities in states with carbon pricing programs

For customers located in Washington and subject to the state's cap-and-invest program, Markets+ design is superior because it better supports customers' ability to claim the low-carbon attributes of the federal system. Markets+

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[120] *See, e.g.*, CAISO, Average Emissions Rate Report, *available at* https://www.caiso.com/library/average-emissions-rate-reports.

design (for "Type 1A" attribution of power to a state) will result in greater assurance that power from the federal system will be attributed to Bonneville's Washington customers. Markets+ design allows participants to register resources as "Type 1A" if they have contracts with load in the GHG Pricing Zone.[121] This "Type 1A" treatment recognizes that utilities have entered into contractual arrangements to procure clean or low-carbon energy and honors those contractual agreements by attributing the resource (if it is economical within the market dispatch) to load in the state. This "Type 1A" treatment is a critical feature that will allow customers to identify federal resource amounts that are contracted to its customers in Washington[122] and the market design will ensure those resources are attributed to Washington load if dispatched.

The Markets+ design recognizes contractual commitments that meet certain qualifications as "Type 1A" resources. Type 1A resources are optimized in the same way as in-state resources, resulting in the inclusion of the appropriate GHG adder in the offer prices and attribution to load in the state with the GHG pricing program. Thus, the design ensures attribution of the low carbon attributes of the federal system to Washington loads that have contracted with Bonneville.

EDAM's design recognizes contractual commitments[123] but not in an equivalent manner to Markets+ Type 1A treatment. EDAM's design recognizes contractual commitments, but does not guarantee the federal system, if dispatched, will be attributed to Washington. The market will seek the most economic solution for the market, including the carbon pricing states (both California and Washington). The federal system could be dispatched and attributed to Washington or it could be dispatched and used to meet load in the rest of the market, when it is the most economical solution for the entire market footprint (this is more akin to Markets+ Type 1B).[124] Thus, EDAM's design, if extended to Washington, would not provide the same level of assurance that federal power would be attributed to Washington loads. Further, EDAM does not appear to support assured attribution, even for self-scheduled resources (although, if it did, self-scheduling would not be an efficient market design because it would not allow for an optimized dispatch when appropriate).

EDAM's market design, paired with the design of Washington's cap-and-invest program, could dispatch fossil fuel generation located inside Washington to help meet power balance of the market as a whole, and attribute the resulting GHG emissions to load across Washington, including that of Bonneville's preference customers. At the same time, less expensive federal power could also be dispatched by the market but not attributed to Bonneville's power customers in Washington. This could occur because in-state resources[125] always have the GHG adder[126] in their dispatch, so the market optimization will by default first deem all in-state resources to be serving load inside the carbon pricing state, to achieve a least-cost solution for the entire footprint of the market. This could happen even if the market also dispatches a cheaper out-of-state clean resource that is contracted to Washington load. While this is a good solution for economic efficiency when considered across the entire market footprint, it can create unintended consequences for Washington loads that have contracts with clean or low-carbon resources located outside of the state. This inability to ensure federal power is attributed to Washington prevents Bonneville's

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[121] *See* SPP Markets+ Tariff, Attach. K §§ 2, 3.2.2.

[122] Currently, in Bonneville's BAA, only its customers in Washington will have load included in a GHG Pricing area.

[123] *See* CAISO, Extended Day-Ahead Market Final Proposal § 7(c) and (d) (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.

[124] Type 1B is energy from a resource with an agreement to supply load inside a GHG pricing zone. Type 1B energy is only attributed to the GHG pricing zone if it is the most economic solution for meeting power balance for the entire market. *See* SPP Markets+ Tariff § 1 (Definitions, Type 1B Energy) and Attach. K § 3.2.3.

[125] In-state resources are generally resources physically located in the state with the GHG pricing program (*e.g.*, Washington). However, pursuant to Washington's Climate Commitment Act, the federal system is considered to be external to the GHG Pricing Zone. *See* Wash. Rev. Code § 70A.65.010(42)(c).

[126] A GHG adder represents the monetary value of an individual resource's emission factor multiplied by the cost of compliance with the respective state program (e.g. cost of allowances). *See* CAISO EDAM Filing, Tariff § 29.32(a) (GHG Bid Adders); SPP Markets+ Tariff § 1 (Definitions, Specified GHG Adder).

Washington customers from claiming the low carbon attributes of the system and therefore equates to increased costs for Bonneville and its long-term firm power purchasers.

5.2.5.1.2. Markets+ Baseline "Threshold" Run recognizes Bonneville's load obligations in determining energy eligible for attribution, limiting the risk that energy contracted to other utilities will be attributed to states with GHG pricing programs

For customers located outside Washington, Markets+ design (the "threshold enhanced floating surplus" approach)[127] gives Bonneville the ability to manage how much energy from the federal system can and cannot be attributed to load in a state with carbon pricing (referred to as a GHG pricing area). Bonneville expects that the low-carbon nature of the federal system will often make it a least-cost option (including GHG cost), and, thus, result in attribution to load in California or Washington. Markets+ design includes market mechanisms that largely limit the amount of energy (aside from contracted amounts) that can be attributed to a GHG pricing area to circumstances when that energy is surplus to a market participant's total load obligations.

Markets+ design enables the resource owner to set a threshold reflective of the market participant's load obligations. Markets+ uses a baseline run that takes those obligations (the "threshold") into account by only making amounts dispatched over the threshold available for attribution to a GHG pricing area. The threshold run looks at the entire footprint of the market and is currently expected to run approximately every 15 minutes[128] and should yield results that are fairly aligned with the optimization and ultimate dispatch of the resource. In other words, the existing load obligations of the resource are a direct consideration of how much energy is eligible for and ultimately attributable to a GHG pricing area. This is a key feature of Markets+ design that would help ensure that Bonneville's customers can continue to claim the low-carbon attributes of their federal system power purchases for applicable state programs or for their own purposes.

While the newly adopted EDAM design will allow a participant to indicate how much energy they are willing to attribute to a GHG pricing area,[129] there is no in-market mechanism that aligns the participant's load obligations to the baseline run or optimization and resource dispatch. Rather, EDAM's baseline run (the "reference pass")[130] takes a broader look at resources across the market footprint to establish eligibility for attribution. As the CAISO explained in its EDAM filing, the EDAM counterfactual will "approximate how a balancing area outside the GHG regulation areas will meet its own load with its internal generation as well as supply from other balancing areas outside of the GHG regulation area. The goal of the GHG reference pass is to reflect how supply resources can optimally serve demand in the EDAM footprint without net imports into the GHG regulation areas and the associated cost of compliance with GHG regulation."[131] As a practical result of this, EDAM limits attribution of a resource to amounts that are determined to be surplus to the load needs of the entire market footprint rather than surplus to the participant's load obligation.[132]

Bonneville has two concerns with the EDAM design. First, this design incorrectly assumes that the best way to prevent leakage[133] is by assuming the load obligations of all market participants external to the GHG pricing area

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[127] *See* SPP Markets+ Tariff § 1 (Definitions, Surplus Threshold) and Attach. K §§ 3.4, 3.7.
[128] Email exchange between Bonneville and SPP (on file with author).
[129] *See* CAISO, Extended Day-Ahead Market Final Proposal § 7(b)(3)(a) (Dec. 7, 2022), *available at* https://stakeholdercenter.caiso.com/initiativedocuments/finalproposal-extendedday-aheadmarket.pdf.
[130] *See* CAISO EDAM Filing, Transmittal Letter at 163-69; CAISO, Extended Day-Ahead Market Final Proposal § 7(b)(3)(c).
[131] See CAISO EDAM Filing, Transmittal Letter at 163-69.
[132] The EDAM excludes committed capacity from the baseline run. In other words, committed capacity will always be eligible for attribution to the GHG pricing area that the load it is contracted to is in.
[133] "Leakage" as used in this context is a reduction in GHG emissions within one jurisdiction that is offset by an increase in GHG emissions in another jurisdiction. See, for example, the definition of leakage in the California Global Warming

must be met before a resource could have surplus energy available for attribution to the GHG pricing area. This unnecessarily limits attribution from a particular resource, which may not be fully obligated (or obligated at all), which can disadvantage not only the seller of clean and low-carbon energy but also the state with the pricing program because the remaining resources eligible for attribution tend to be higher cost. Rather, the more appropriate measure is whether an individual resource (or system of resources, in Bonneville's case) has surplus energy available above its particular load obligations. As discussed above, Bonneville believes the Markets+ design appropriately focuses on energy amounts surplus to an individual resource's load obligations.[134]

Bonneville notes that there is a related concern with CAISO's BAA net export constraint,[135] which limits attribution from resources in a BAA where that BAA is a net importer.[136] However, the BAA is also not the appropriate measure of whether an individual resource has surplus energy available to meet load in a GHG pricing area. While the Bonneville BAA as a whole may be a net importer, that does not identify whether individual non-federal resources or the federal system is surplus in relation to each resource's individual load obligations.

Second, under EDAM's design, the actual optimization could dispatch the resource at levels lower than those reflected in the reference pass, which could result in significant amounts of the federal system being attributed to California even though that power is contracted to Bonneville's customers in other states under long-term power sales contracts. While this can happen as well with Markets+'s design, the risk is minimized because, as discussed above, the threshold run is 1) based on all loads and resources in the market and 2) expected to be run every 15 minutes.

CAISO's existing market, the WEIM, demonstrates Bonneville's second concern. In the WEIM, there are often times when the amount of federal system WEIM dispatches that are attributed to California are greater than the amount that Bonneville's BAA is exporting to the WEIM. Specifically, when there is a non-zero GHG shadow price, meaning some carbon emitting resources are being attributed to California,[137] about 90% of Bonneville's WEIM power sales are being attributed to California. This occurs even though there may be a negative imbalance[138] in Bonneville's BAA (i.e., Bonneville BAA is importing from the WEIM) and customers have contracts with Bonneville for forward supply. A day-ahead market would subject a larger portion of the federal system to this effect. CAISO has taken recent steps to improve the GHG accounting design in EDAM by switching to a baseline

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Solutions Act of 2006 (Assembly Bill 32, or AB32), *codified as* Cal. Health and Safety Code Div. 25.5, §§ 38500-99.11. CAISO uses the term "secondary dispatch" to identify when leakage is occurring in its market design because a resource has been attributed to a jurisdiction (California) at levels below the resource's baseline.

134 Bonneville notes that emissions leakage (also referred to as secondary dispatch in a markets context) is a state issue as opposed to a markets issue. Individual state programs may have differing views on whether leakage needs to be addressed and, if so, how stringently. CAISO's approach to minimize leakage is purportedly a California approach as the California Air Resource Board's cap-and-trade program was the only pricing program in effect with guidance on leakage at the time of EDAM development. Conversely, SPP's approach provides more state flexibility to determine parameters around the appropriate amount of leakage. This is because a resource owner's threshold can be informed by guidance from a state on what constitutes surplus energy that is eligible for attribution to the state.

135 *See* CAISO EDAM Filing, Tariff § 29.32.1.

136 The EDAM net export constraint does not apply when the BAA is located in a GHG pricing zone and does not limit committed capacity from being attributed to a GHG pricing zone.

137 Bonneville uses its Asset Controlling Supplier emission factor to inform its GHG bid offer for California, resulting in a very low, but non-zero GHG emissions cost.

138 The WEIM Transfer is an algebraic quantity (positive for export and negative for import) for the net energy exchange between a given BAA and the remaining BAAs in the WEIM Area. *See* CAISO Business Practice Manual for the Western EIM, Appendix A: Mathematical Formulation for WEIM Transfer § 16.2.1.1.1, *available at* https://bpmcm.caiso.com/BPM%20Document%20Library/Energy%20Imbalance%20Market/BPM_for_Energy%20Imbalance%20Market_V33_Clean.docx.

run[139] and adding the BAA next export constraint for EDAM. Bonneville expects that these updates will help reduce this effect but not minimize it as effectively as the Markets+ design. In the event this occurs in EDAM, it could undermine the ability for Bonneville's customers in other states, like Oregon, to claim energy from the federal system for GHG reporting purposes, despite the fact that they hold long-term contracts for federal system purchases.

5.2.5.2. GHG tracking and reporting for non-pricing programs and general needs of market participants

Both EDAM and Markets+ are also developing more broadly applicable GHG accounting solutions that could support meeting the requirements of states with non-pricing programs (e.g., emission reduction standards that do not explicitly place a price on carbon), as well as the GHG accounting needs of any individual market participant. Bonneville views these solutions as essential to its customers' ability to retain the GHG benefits of the federal system.

Markets+ has developed and adopted a novel out-of-market GHG accounting solution designed to support the needs of market participants, whether to meet requirements of a state non-pricing program, local requirements, or individual utility goals.[140] The accounting framework will assign to a market participant the dispatched energy for the market participant's owned and contracted-for resources up to the amount of the market participant's load. This will ensure (subject to state GHG reporting rules) that market participants can claim and report the clean resources in which they have invested. Bonneville has confidence that the Markets+ solution will support Bonneville's customers' ability to continue to claim the low-carbon attributes of the federal system regardless of the state in which the customer is located.

EDAM work to develop a similar approach is in progress.[141] In December 2024, CAISO published an issue paper that outlines reporting design options and some tradeoffs.[142] It is uncertain whether the approach CAISO ultimately adopts will support the needs of Bonneville customers. At this time, Bonneville has more confidence that the Markets+ design for accounting and reporting will meet the needs of its customers.

5.2.5.3. GHG Takeaways

Markets+ includes a GHG accounting design that fairly assigns Bonneville's carbon-free generation to Oregon and Washington customers. The EDAM design continues the status quo of California customers obtaining disproportionate credits for out-of-state low-carbon generation. As these market design differences persist, they serve to increase costs for Bonneville's Washington customers who participate in Washington's carbon pricing program, and they result in Oregon customers receiving less credit than they are entitled to meet their state's requirements.

As described above, Bonneville has made an informed comparison between the market designs of EDAM and Markets+ related to GHG accounting. Bonneville believes that the Markets+ GHG accounting approach (the dispatch-based solution for carbon pricing programs combined with a broadly applicable out-of-market resource

[139] The EIM currently limits attribution of a resource to a GHG pricing area to the difference between the resources Upper Economic Limit and Base Schedule. In the future, for EDAM participants, the CAISO will use the difference between the day-ahead market energy schedule and day-ahead market GHG award. *See id.* § 11.3.3.2; CAISO Extended Day-Ahead Market Final Proposal § 7(b)(3)(c).
[140] *See* SPP, Markets+ GHG Task Force, *available at* https://www.spp.org/stakeholder-groups-list/western-energy-services-stakeholder-groups/marketsplus-stakeholder-groups/marketsplus-independent-panel/marketsplus-participant-executive-committee/marketsplus-design-working-group/marketsplus-ghg-task-force/; SPP Markets+ Protocols § 5.8 ([GHG] Tracking and Reporting).
[141] *See* CAISO, Greenhouse Gas Coordination Work Group, *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Greenhouse-gas-coordination-working-group.
[142] CAISO, Greenhouse Gas: Accounting and Reporting Issue Paper (Dec. 20, 2024), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/AccountingandReportingIssuePaper-GreenhouseGasCoordination-Dec202024.pdf.

and emissions assignment available to all market participants) is an equitable approach to the needs of all market participants to meet various reporting programs, and provides a path for Bonneville's customers to continue to report low-carbon attributes associated with purchases from Bonneville. Further, the Markets+ governance structure enabled it to successfully continue to refine a widely supported solution for GHG accounting. In addition, SPP's stakeholder process provides superior flexibility, allowing participants the opportunity to revise the GHG accounting design to account for changes in the GHG reporting landscape. Bonneville recognizes the market participants' ability to make stakeholder-driven improvements and adjustments to market design is particularly important in this complex and evolving area.

5.3. Summary Recommendation

Bonneville recognizes that its day-ahead market Policy direction towards participating in Markets+ will play a critical role in the energy and capacity market landscape for the region, and it will have direct impact on a number of other entities' decisions regarding day-ahead market participation. Bonneville has carefully considered the financial analyses, design comparisons, expected footprints, and various other details through the lenses of our evaluation principles. Bonneville sees participation in a day-ahead market as an important step in maintaining access to trading partners to continue meeting obligations and marketing surplus to maintain low rates for customers.

Bonneville has determined that Markets+ is the best option because of its superior governance and stakeholder process and its superior design, and believes it has the potential to offer financial benefits that are greater than business as usual. While several market design issues described above, such as congestion revenue allocation, GHG accounting, and fast start pricing, cannot be decisively quantified, Bonneville believes the Markets+ design is likely to provide economic benefit and partially offset the financial benefits attributed to EDAM by the PCM studies. Bonneville will work diligently to meet the needs of its power and transmission customers, including by maintaining access to trading partners and minimizing market-to-market friction. Bonneville acknowledges the potential financial tradeoff and potential increased implementation and participation complexity given differing decisions by other adjacent entities. However, these tradeoffs must be evaluated along with potential mitigation and the business drivers associated with relevant quantitative and qualitative factors. Based on comprehensive business evaluations presented in this Policy, Bonneville concludes that the design of Markets+ is best positioned to satisfy Bonneville's business needs, statutory and contractual obligations, and the broad and evolving needs of Bonneville's customers.

6. Preliminary Implementation and Participation Considerations for Markets+

Throughout Bonneville's public process, Bonneville explained generally how a day-ahead market will affect Bonneville and its customers. Bonneville discusses a summary of Markets+ implementation and participation elements in this section. Further details will continue to be developed as Bonneville progresses through implementation of day-ahead market participation in Markets+.

Bonneville's Policy direction to join Markets+ impacts all generation and load in the Bonneville BAA to some degree. In addition to requirements laid out in the market tariff and associated supporting documentation, Bonneville will memorialize requirements and rate information specific to its BAA in its tariff, rate schedules, and business practices as part of the public processes it carries out for each of these documents.

6.1. Generation Resource Participation in Markets+

Bonneville anticipates the following details of participation framework in Markets+.

All output is settled

In Markets+, all resources above a certain size[143] in Bonneville's BAA will be subject to the market tariff and rules,

[143] In the WEIM, Bonneville requires all generators above 3 MW to be modeled. *See* Bonneville Power Administration, Energy Imbalance Market (EIM) Business Practice V.5 §§ D.3, G.6 (May 30, 2023).

which Bonneville will propose to incorporate into its Tariff and business practices.[144] Under the terms of the Markets+ Tariff, all generation output will be settled at market prices.[145] The basic energy settlement equations are described in Section 6.6.[146]

All resources participate, but can self-schedule

In the context of the WEIM, "participating resources" are resources registered directly with the WEIM that can offer flexible range to the market via a bid curve, and "non-participating resources" are all other resources that do not bid directly into the market. In both day-ahead markets, all resources are considered "participating" because their full output impacts the market solution, and they are settled for that full output. However, this does not mean that all resources must offer flexibility. In addition to the ability to offer price-sensitive energy between a minimum and maximum generation point, both markets also allow for "self-scheduling" which is an indication to the market that a resource plans to generate a specific MW amount and is not offering price-sensitive flexibility to the market. The resource will still be settled for that submitted self-schedule at the relevant market LMP, as the submitted self-schedule becomes the day-ahead market solution award for that resource, and that resource will still be settled for real-time output relative to that day-ahead award.

Resources can still export out of the BAA

Joining Markets+ will not prevent or limit resources in the Bonneville BAA from transacting with entities outside the Markets+ footprint. Entities can still export from their resources out of the footprint as long as the export is properly tagged, as is required today to sell an export out of the Bonneville BAA. Note that this does not require a resource to opt their transmission out of the market. Resources can schedule on their transmission to indicate the export, and then either self-schedule enough output to serve the export or offer the resource into the market and let the market choose the most economic resource mix to serve the export obligation. This is further discussed in section 6.8.

Resources and loads must have a direct relationship with the Market Operator

In Markets+, all registered resources and loads must have a direct relationship with the Market Operator via a Market Participant[147] Agreement. Multiple resources and multiple loads can be registered under a single market participant. The market operator will directly receive data submissions from the market participant and will settle directly with the market participant for nearly all charge codes. This differs from the WEIM framework, where the market settles with the BA for all loads and non-participating resources and the BA subsequently sub-allocates the charges. At this time, Bonneville has not determined whether it will offer options for resources in its BAA to schedule into the market through Bonneville (e.g., simply by submitting a schedule to Bonneville via e-tag or Bonneville's Customer Data Exchange, as is done for non-participating resources in the Bonneville BAA for WEIM today). Note that for the few charge codes paid to the TSP or BA, Bonneville will determine the suballocation of those funds in a future Rate Case proceeding.

Independent resources do not have an automatic must-offer obligation

The Markets+ Must-Offer Obligation is measured at the market participant level. Independent resources do not have individual must-offer obligations unless they have export schedules (in which case, they must offer or self-schedule their resource to fulfill the export schedules). Otherwise, individual resources contribute to meeting the Must Offer

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[144] *See* Section 5.1.1.6 (Power Business Line) above and Section 6.6 (Markets+ Settlements) below for more details.
[145] SPP Markets+ Tariff, Attach. A § 6.2(6). An MP must register all gen in footprint above 0.1 MW unless behind the meter under 10MW (note: the BPA BA uses 3MW, not 10MW, for BTM in EIM, as indicated in the previous footnote).
[146] *See also* SPP Markets+ Tariff, Attach. A §§9.2 (Day-Ahead Market Settlements), 9.3 (Real-Time Balancing Market Settlements).
[147] Pursuant to the Markets+ Tariff Definitions: "Market Participant (MP): An entity that executes the Market Participant Agreement in Attach. E, or on whose behalf an unexecuted Market Participant Agreement has been filed at FERC."

Obligations of market participants with load by being a resource within that market participant's registration. The market participant can also indicate a contract with the resource that they put toward their must-offer obligation.

Resources must provide offer information in accordance with market timing

The timing for the day-ahead market run to "close" (at which point the day-ahead market optimization begins, and no new input information can be incorporated) in Markets+ is 10 a.m. on the day prior to the relevant operating day, with results expected to be posted by 1:30 p.m. Markets+ runs the Reliability Unit Commitment (RUC) process at least every four hours between the day-ahead market solution and real time. The RUC provides unit commitment information to resources that have indicated their willingness to be committed by the market but is otherwise not financially binding for purposes of energy settlement. The timing for the real-time market run to close is 30 minutes prior to the relevant operating hour ("T-30"). Offer information, including MW amounts and associated pricing, can be changed after the 10 a.m. day-ahead close at any point until the T-30 deadline and is incorporated into any subsequent RUC and real-time optimizations.

Potential for non-BA requirements

Note that the information in this section generally pertains to participation based on Markets+ requirements and the expected framework in the Bonneville BAA. For resources that are owned by or contracted to power customers of Bonneville Power Services, there may be further requirements. Those requirements will be determined as part of a public process as discussed in Section 6.7.

6.1.1. Federal Generation

Markets+ will allow resources to be registered as individual units or as aggregated resources. Bonneville intends to use the same resource aggregations as is used in WEIM. Resource aggregates are further discussed in Section 6.1.1.2.

Bonneville will prioritize its statutory obligations such as fish passage and flood control over market actions, as it does today, which may limit Bonneville's ability to participate in the market during times of limited hydraulic flexibility.

Bonneville expects to use self-schedules and offer ranges to ensure the FCRPS operates within its limits while allowing for system optimization. In addition to hourly minimum/maximum constraints, Markets+ has also developed an additional constraint, allowing Bonneville to communicate a daily energy maximum for each resource in the day-ahead optimization in addition to the hourly offer range limits. Setting a daily energy maximum helps ensure that Bonneville can honor operational obligations and constraints while still allowing for economic optimization of the system. Further, because offers can be updated through real-time, Bonneville will be able to make adjustments to its planned operations in the market as fuel certainty materializes.

6.1.1.1. Impacts on Hydro Operations in Relation to Fish & Wildlife

In Markets+, Bonneville will continue to meet its statutory obligations, including those under the Northwest Power Act, Endangered Species Act (ESA), and National Environmental Policy Act (NEPA). Bonneville's power marketing services and activities, and its actual power operations to meet load obligations, are conducted consistent with applicable Biological Opinions and are within existing operating constraints and normal operating limits of FCRPS projects. The Markets+ framework allows Bonneville to manage FCRPS operations with other project purposes and system-wide operating constraints, including operations to support ESA-listed fish and to provide equitable treatment for fish and wildlife with other system purposes as required by the Northwest Power Act.

6.1.1.2. Use of aggregation model for Federal resources

As part of the decision to enter the WEIM, Bonneville opted to use the aggregation model to represent the Big 10 hydro resources.[148] The aggregation model has worked well in the WEIM, and Bonneville plans to maintain this approach for day-ahead market participation in Markets+.

The resources within an aggregation model are hydraulically interdependent; water released out of upstream resources will affect the operation of downstream resources within a matter of hours. Hydro operators must account for this relationship along with fuel uncertainty (e.g., expected water flows versus real water flows due to weather, third party resource operations, etc.). This dynamic, combined with the various non-power constraints and physical project limitations, results in the need for hydro operators to have flexibility to adjust between resources as necessary. Aggregation of hydro resources allows Bonneville and its federal partners to maintain this flexibility to manage the impacts of market activity and uncertainty in operational and hydraulic objectives.

In the WEIM, Bonneville uses three aggregations to provide maximum flexibility for hydro operators while providing the market with maximum ability to redispatch resources for congestion relief. Bonneville grouped the resources that were most interconnected based on river reach area (Upper Columbia,[149] Lower Snake,[150] and Lower Columbia[151] areas).[152]

Bonneville has worked closely with SPP and stakeholders in the Markets+ process to design an aggregation model for use in Markets+. Bonneville has not yet determined if there are other groups of resources in the federal hydro system that would benefit from aggregation but plans to consider that question during implementation.

6.2. Ensuring Adequate Supply in Markets+

Today, Bonneville works across all timeframes to preserve and maximize the value of the FCRPS for customers through prudent operational planning and marketing practices. Bonneville sets its system up to provide the most economic and reliable energy supply to customers while planning for contingencies and required operations such as those for fish and wildlife. Bonneville also plans the system to make economic purchases and high-value surplus sales to bring added revenue to help lower firm power rates. Bonneville's primary goal in its proposed participation in Markets+ will be a continuation of what it does today: provide firm power supply for its long-term power sales contracts. Bonneville will continue to plan for its long-term firm power load service obligations by managing its existing resources and by acquiring resources in advance based on forecasted need. Bonneville does this in its Pacific Northwest Loads and Resources Study (also known as the White Book) and through its Resource Program, both of which supplement the regional power plan prepared by Northwest Power and Conservation Council pursuant to the Northwest Power Act.

Bonneville's future participation in WRAP binding operations and Markets+ will provide greater transparency and documentation as to how these obligations are met. Bonneville's loads and resources planning for its long-term power customers will be reflected for long term planning in its WRAP obligations and for short term planning in the requirement that Bonneville meet the Markets+ resource sufficiency mechanism, the Must Offer Obligations. The Must Offer Obligation is a minimum requirement for each market participant in Markets+ with load and/or export obligations to bring enough supply to "cover" those obligations. Through its long-term planning (reflected in the WRAP Forward Showing program and Bonneville's White Book), and its short-term planning practices (demonstrated in the Must Offer Obligations and WRAP Operations Program), Bonneville will ensure that its long-term firm power sales contract obligations are satisfied.

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[148] The "Big 10" Hydro Resources are: Grand Coulee, Chief Joseph, Lower Granite, Little Goose, Lower Monumental, Ice Harbor, McNary, John Day, The Dalles, and Bonneville Dams.
[149] Aggregation of Grand Coulee and Chief Joseph Dams.
[150] Aggregation of Lower Granite, Little Goose, Lower Monumental, and Ice Harbor Dams.
[151] Aggregation of McNary, John Day, The Dalles, and Bonneville Dams.
[152] For more information on this decision, please see Bonneville Power Administration, EIM Participation Letter to the Region, Attach. A § III.e.1 (June 20, 2019), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalance-market/20190620-western-energy-imbalance-market-letter-to-the-region.pdf.

6.3. Ancillary and Control Area Services

Ancillary and Control Area Services (ACS) are services necessary to support the transmission of energy and capacity while maintaining reliable operation within and among BAAs. Bonneville is required to offer ancillary services under its Tariff, and transmission customers may purchase certain ACS from Bonneville or self-supply through a customer's own resources. In general, ACS are necessary to maintain the reliability of the BAA. There are typically two components to most ACS: capacity (the ability to produce energy when needed) and energy (the actual production of energy). Energy and Generation Imbalance, which are used for the sub-hourly provision of energy to maintain load-resource balance within the BAA, are two important ACS that Bonneville currently offers. Bonneville currently provides Energy and Generation Imbalance service through the WEIM under Schedules 4E and 9E of Bonneville's Tariff.[153] There is currently no centrally organized market for the capacity component of ACS proposed for Markets+ or EDAM, which Bonneville provides under Schedules 3 and 10 of its Tariff.

Participation in Markets+ does not eliminate Bonneville's requirement to offer ACS, as the market operator will not be taking over this responsibility. Markets+ includes the Real-Time Balancing Market (RTBM), which is similar to the WEIM. The RTBM is an intra-hour (or real-time) centralized energy market used to economically dispatch participating generation resources to balance supply, transfers between BAAs (interchange), and load across the market's footprint. Like the WEIM, RTBM is not a capacity market. Bonneville does not expect Markets+ to change how ACS is provided. However, Bonneville will likely need to revise its tariff, rates, and business practices to incorporate Markets+. Those revisions will occur separately in the appropriate processes.

6.4. Operational and Commercial Seams

As described by FERC, seams issues include differences in transmission rules as well as differences in power market rules. Operational seams include multifaceted matters such as coordination of generation and transmission maintenance schedules, determining how path flows affect outside areas, congestion management procedures, operating rules for recalling firm transmission capacity, demand response rules, and communication protocols. Commercial seams encompass different market constructs such as bidding rules, market product definitions, market price intervention practices, different business practices, generation and transmission scheduling practices, and processes to verify transactions between market operators and market participants.[154]

Bonneville and other BAAs will need to manage new operational and commercial seams as entities join day-ahead markets. For example, Bonneville has generation and load in other BAAs that are likely to join EDAM, such as the PacifiCorp (PAC) and Portland General Electric (PGE) BAAs. In addition to the obligation to customers located in those BAAs, many entities affected by the implementation of day-ahead markets will need to manage commercial seams and possibly multiple markets. These seams can be mitigated through coordination across the various participants, including market operators, BAAs, market participants, and the various regional groups who coordinate among WECC today.

As explored in detail in Appendix D, the development of day-ahead markets will create new operational seams in the Western Interconnection. Bonneville's transmission system covers large portions of the Pacific Northwest and is not always contiguous. There are also a number of transmission asset owners, BAAs, and transmission capacity owners of operational paths within Bonneville's Pacific Northwest service territory, including the Pacific DC Intertie (PDCI) and Northwest AC Intertie (NWACI). Bonneville will be able to manage operational complexities like congestion management by developing coordinated operating agreements like those for WEIM.

CAISO and SPP will have their own RC offerings tasked with ensuring system reliability for their registered

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[153] Bonneville is providing imbalance service under Schedules 4 and 9 during the periods that Bonneville pauses WEIM participation.

[154] *Remedying Undue Discrimination Through Open Access Transmission Service and Standard Electricity Market Design*, 67 Fed. Reg. 55,452 55,464-65 (Aug. 29, 2002).

Transmission Operators. RCs, market operators, and market participants will develop agreements to manage seams to support reliable operations, like they have in the eastern states for decades. The ability of a region with multiple energy markets in it to effectively manage congestion is strongly dependent on both markets calculating impacts on a path the same way, so that actions taken during congestion management have the desired effect in both market footprints.

6.4.1. Commercial Seams

As also explored in detail in Appendix D on seams management, the development of day-ahead markets will create new commercial seams. Today, many of Bonneville's commercial seams are between the bilateral and non-bilateral markets. The industry has created tools and means of transacting which mitigate the impacts of these commercial seams such as ensuring power sales and purchases have some uniform provisions by largely adopting the WSPP, Inc. (formerly Western Systems Power Pool) standardized WSPP Agreement.[155] Multiple day-ahead markets within the West would require the development of new tools and methodologies to manage commercial seams.

6.4.2. How market participation may impact transmission congestion issues

Bonneville has observed the ability of WEIM to manage operational constraints and expects even greater congestion management effectiveness with the addition of a security constrained day-ahead market optimization. However, Bonneville acknowledges that two day-ahead markets will create a need for operational coordination between the markets, particularly given the non-contiguous nature of the potential market footprints. The ability of an energy market to effectively manage transmission system congestion depends on the footprint and size of that market. This includes the size, location, and offered flexibility of the resources supplying energy to that market, the size and location of the loads purchasing that energy, and the volume of transmission available to that market relative to those resources and loads. The day-ahead schedules and awards from each market, if properly implemented and coordinated, should be physically feasible within the market-available transmission capacity.

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. Appendix E discusses in more detail those impacts as they are related to congestion management. Bonneville expects agreements, constraints, and market design to mitigate operational and commercial seams issues. Given the complexity of the Western Interconnection, the potential for non-contiguous market and RC footprints, and the number of parties involved, multiple types of agreements will be necessary.

6.5. Operational Tools

Bonneville employs many operational tools to reliably operate the federal power and transmission systems to meet its Tariff, compliance, and environmental requirements. At this time, Bonneville expects to continue to use a majority of these operational tools in Markets+.

Some of these tools will require adjustments to work within the framework and day-ahead market timelines of Markets+. Bonneville will continue to identify which operational tools will require adjustments as part of implementation scoping and will work with the market operators as necessary as part of that scoping process.

6.5.1. Curtailment Advisor

Bonneville anticipates adjusting its Curtailment Advisor tool used for performing transmission curtailments in real time when flow on a path exceeds the established limit. Today, when initiated, Curtailment Advisor curtails e-tag schedules impacting the given path in real time according to NERC curtailment priority. In the real-time market, the market optimization will redispatch every five minutes in real-time to maintain market flows within the established market transmission limit. If the market is unable to redispatch enough to avoid violating the limit, responsibility reverts to the TOP to determine if actions are needed to protect the path. However, because BAA-to-BAA e-tags with "system" sources are typical in a day-ahead market framework, Bonneville will need to develop

[155] *See WSPP, Inc.*, FERC Docket No. ER25-178, Letter Order (Dec. 13, 2024).

a method to address effective transmission curtailments based on NERC priority. Bonneville anticipates working through this topic as part of its implementation phase.

6.5.2. Operational Controls for Balancing Reserves (OCBR)

OCBR is a real-time operational tool used by Bonneville to manage reliability when balancing reserve capacity is depleted. Balancing reserve capacity is capacity held to address sub-hourly load and generation error as measured against an hourly schedule across the Bonneville BAA. Incremental or "INC" capacity is deployed when there is under-generation relative to load and decremental or "DEC" capacity is deployed when there is over-generation relative to load.

Before Bonneville's entrance into the WEIM, the use of OCBR for an INC depletion event resulted in the curtailment of hourly schedules to actual generation levels for significantly under-generating resources. The use of OCBR for a DEC depletion event resulted in limiting generation to the scheduled amount for significantly over-generating resources.

Upon joining WEIM, Bonneville adjusted the design of the OCBR tool to better fit with the real-time market structure and leverage the additional sub-hourly energy available in the market. For example, Bonneville shifted the measurement of balancing reserve depletion to consider only the portion of balancing reserves served exclusively by Bonneville's own resources (regulation), and not the portion served by WEIM dispatches (non-regulation).

Bonneville expects few, if any, changes to OCBR when joining Markets+. OCBR[156] is a real-time tool and the day-ahead market elements of Markets+ should not have any impact. As RTBM in Markets+ operates similarly to the WEIM, OCBR should work with the RTBM in the same manner.

6.5.3. Oversupply Management Protocol

Oversupply Management Protocol (OMP) is an operational tool used to address certain environmental conditions in the Columbia River, while maintaining reliability in Bonneville's BAA. During times of high river flows, typically in the spring when loads in Bonneville's BAA are low, water must be passed through the dams in one of two ways: spilled over the dams or run through the turbines to generate electricity. When water is spilled over the dams, it creates bubbles of air in the water that, at certain levels, can be harmful to salmon and other aquatic species. This is referred to as total dissolved gas and is regulated by Oregon and Washington under the Clean Water Act.

When the Columbia River reaches total dissolved gas limits, Bonneville must limit spill by passing water through the generating turbines, thus creating electricity. Bonneville sells this electricity at market rates, but, in the Spring, there are occasions when there is not sufficient load to use the electricity, even at zero cost. As a result, Bonneville adopted Attachment P to its Tariff, creating a least-cost cost curve for displacing generation in the BAA and reimbursing displaced generators for certain costs related to the displacement so that Bonneville can pass water through its generating turbines and maintain load-resource balance. Attachment P has been approved by FERC under section 211A of the Federal Power Act.

Bonneville expects to retain OMP in Markets+ and will review if any process changes are necessary to adapt to market rules and timing. While Markets+ may provide Bonneville additional opportunities to market generation during times of high flows, Bonneville still needs a mechanism to ensure compliance with its environmental responsibilities. As Bonneville gains more experience in Markets+, it will monitor the need to adjust or retain OMP.[157]

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[156] *See* Bonneville Power Administration, Operational Controls for Balancing Reserves, *available at* www.bpa.gov/energy-and-services/transmission/ancillary-services/balancing-reserves/operational-controls-for-balancing-reserves.

[157] *See* Bonneville Power Administration, Oversupply, *available at* www.bpa.gov/energy-and-services/transmission/oversupply.

6.6. Markets+ Settlements

Markets+ will settle directly with each market participant for the majority of its charge codes, including day-ahead awarded energy and imbalance energy. Settlement volume will be larger in a day-ahead market than in a real-time only market. As discussed in section 6.7, Bonneville expects to be the market participant on behalf of Load Following customers in the Bonneville BAA and thus will settle with Markets+ on behalf of those customers. Other market participants[158] will receive their settlements directly from Markets+.

Markets+ settlements are more streamlined than EDAM. Markets+ utilizes a simpler 12-month settlement process with three settlement statements and ~40 charge codes, as opposed to the EDAM settlement period of 24-months with five settlement statements, and a much larger number of charge codes to manage.[159] Markets+ settles directly with market participants. Receiving settlements directly through the Market Operator, rather than suballocated by the BA, as is done in WEIM, allows for more direct payments and charges, as well as more timely financial resolution. These aspects are likely to be especially favorable to independent power producers and other larger participants, as well as to Bonneville and its customers, by reducing the workload and associated costs of handling settlements for large entities within the BAA.

While there are a number of charge codes, the most essential settlements are for day-ahead energy awards and real time imbalance energy. As previously described, the award from the day-ahead solution is settled at the day-ahead LMP and is used as the financial reference point for settlement of energy in the real-time solution.

The general equation for energy settlement[160] for a resource is:

Total Energy Settlement = Day-Ahead Award * Day-Ahead LMP + ((Real-time Output – Day-Ahead Award) * Real-time LMP)

And for a load is:

Total Energy Settlement = -1*(Day-Ahead Cleared Load * Day-Ahead LMP + ((Real-time Load Consumption – Day-Ahead Cleared Load) * Real-time LMP))

In the load settlement equation, multiplication by -1 indicates a settlement in the opposite direction (i.e., a payment versus a charge).

6.7. Bonneville Power Services Customer Participation in Markets+

Bonneville's participation in Markets+ will be consistent with the obligations of its Provider of Choice power sales contracts. These contracts include the terms and conditions of the products and services that Bonneville offers its power customers and defines the obligations that both Bonneville and the power customer must meet. Bonneville will look to accommodate power customers' participation in the market consistent with the obligations associated with their product and service elections.

Bonneville recognizes that it does not currently have enough information to include language in the ongoing development of its next long-term power sales contract that would adequately address all the necessary day-ahead market terms and conditions. The Provider of Choice power sales contracts will include a provision that will enable the parties to amend the power sales contracts as needed. Such amendments will include any necessary changes to align with both an updated Bonneville Tariff and the Markets+ Tariff (including associated settlements under Markets+). Bonneville will hold a public process to review proposed standardized amendment language and offer an opportunity for public comment on that language. The Provider of Choice power sales contracts will also include

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[158] *E.g.*, Planned Product customers, independent power producers, etc.

[159] Bonneville has federal resources and preference loads in EDAM BAAs, so to the extent settlements are required, Bonneville will coordinate with EDAM or its participating BAAs and affected customers.

[160] Day-ahead markets contain many other charge codes. This is a simplified example showing basic energy settlement.

a provision establishing that Bonneville will conduct a subsequent public process on the topic of settlements for the Slice Product following Bonneville participating in the day-ahead market.

For Load Following customers, Bonneville expects to be the market participant on behalf of customer loads that are in the Bonneville BAA. Bonneville will work with Load Following customers with load outside the Bonneville BAA to determine the appropriate participation model. Load Following customers for which Bonneville is the market participant and that have dedicated non-federal resources may be eligible to have those resources participate in the day-ahead market consistent with their contractual obligations and requirements. For example, Load Following customers with dispatchable resources may be allowed to offer flexibility to the day-ahead market. Bonneville expects that Load Following customers that elect to offer their own resources into the market for dispatch would be expected to offer capability to the market consistent with any peaking requirements defined in their contracts.

Planned product customers include Slice/Block customers and Block customers. For planned product customers that are in the Bonneville BAA, Bonneville anticipates that a planned product customer will act as the market participant for both their own load and any non-federal resources they wish to bid into the market. Bonneville will work with planned product customers with load outside the Bonneville BAA to determine the appropriate participation model. Bonneville will work with planned product customers to determine how the power supplied by Bonneville is accurately reflected in both Bonneville's and the planned product customers' market participation. Planned product customers will continue to purchase power consistent with their planned obligation and would be expected to be responsible for any day-ahead or real-time load variances.

As an overall observation, Bonneville does not expect day-ahead markets to impact certainty of delivery for power customers. Bonneville would continue to schedule contract deliveries in advance of the market operation based on existing transmission rights as necessary. Transmission customers would continue to be entitled to the same curtailment priority under Bonneville's Tariff as they are today. The market dispatch, however, would account for transmission constraints and attempt to redispatch around them, reducing the need for curtailment and improving certainty of delivery.

6.8. Bonneville Transmission Services Customer Participation in Markets+

Bonneville's Tariff provides two types of Transmission Service: PTP[161] Service and NITS.[162] PTP Service allows the customer to move power from a Point of Receipt to a Point of Delivery and is billed on reservation capacity. NITS is available only for service to network load, billed based on metered network load, and includes planning obligations. Markets+ is consistent with the current terms and conditions for transmission service set under the existing Tariff to a great extent, including through the administration of the Open Access Same-Time Information System, and sale of firm and non-firm transmission service. The Markets+ design recognizes that the market does not assume the role of TSP and respects the prevailing OATT framework in the West.

With day-ahead market participation, Bonneville is anticipating some changes in how its customers may utilize their Bonneville transmission rights. Bonneville transmission contract holders will still have the ability to exercise their transmission rights (e.g., schedule, redirect, and resale existing transmission rights) consistent with Bonneville's Tariff, business practices, and any another relevant agreements as they do today during the day-ahead and real-time horizons, though there may be different implications of doing so.

Bonneville shared its preliminary assessment of how transmission may work in a day-ahead market construct at the

[161] Bonneville Power Administration, Point to Point Transmission Service (PTP): An Overview (rev. Oct. 1, 2001), *available at* https://www.bpa.gov/-/media/Aep/transmission/ptp-service/ptp-product-overview.pdf.
[162] Bonneville Power Administration, Network Integration Transmission Service (NT): An Overview (rev. Nov. 10, 2001), *available at* https://www.bpa.gov/-/media/Aep/transmission/nt-service/nt-product-overview.pdf.

public workshop 8 on July 18, 2024.[163] Bonneville shared a Markets+ process timeline for transmission activities for both the TSP/BA and the transmission customer perspective highlighting the complete cycle from pre-market (registration and modeling set-ups) to day-ahead and real-time activities and concluding with settlements. Bonneville provided examples of how transmission rights, both available for the market and opted-out, would be communicated to the market operator along with the associated Service Flow Constraints[164] (SFCs) that will be configured into the market operator's system(s).

By default, Bonneville's transmission customers' transmission rights and unsold ATC will be made available to the market unless specifically opted out as described in the next paragraph. As described in the day-ahead market framework Section 2.4, on a day-ahead basis, Bonneville will communicate the available transmission capacity on various paths to the Market Operator, and the Market Operator will respect those limits in its market optimization in order to commit and award resources to serve the expected load. In real-time, Bonneville will communicate any changes to ATC to the market, and market flows will continue to be able to use any real-time, unscheduled transmission capability on the Bonneville system.

Markets+ permits transmission customers to "opt-out"[165] their transmission rights according to the market rules, which includes no more than once per month and timely communication to the market operator. Informed by stakeholder input, Markets+ has developed a process for the opt-out communication from the TSP/BA to the MO.[166] Furthermore, the frequency of the opt-out communication was set to align with the TSRs congestion rent eligibility verification timeline. The "opt-out" of transmission rights removes that capacity entirely from reflection in the market and potentially any market settlement implications. However, by doing so, the transmission customer will forego the potential congestion rent revenue on the contracted paths if those paths become binding, as well as use of the market to help meet the schedule. The market rules and associated procedures for transmission opt-outs were set to provide an equitable and timely process for Market Participants that may need to opt-out transmission but to also address market power concerns on transmission usage. While Bonneville believes the current design mitigates any concerns with market power related to transmission usage, the Market Monitoring Unit (MMU) will monitor for transmission withholding by market participants that would violate the Markets+ Tariff.[167] Bonneville transmission contract holders that want to participate in another market (e.g., EDAM) may want to "opt-out" transmission from Markets+ so that generation in that market can be optimized across that transmission. Any additional requirements Bonneville places on transmission opt-outs would be determined in a future Tariff proceeding and/or business practice process.

Note that opting-out transmission is not required in order to (a) self-schedule or (b) individually transact outside of the Markets+ footprint. First, for self-schedules, the market optimization still respects generation self-scheduled within the market footprint. If a generator self-schedules, it consumes a portion of market-available transmission capacity, lowering the amount of transmission across which the market can optimize. This transmission capacity is still "in" the market and the transmission rights holder is still eligible for congestion rent allocation. Second, for transactions that cross the boundary of the Markets+ footprint, those transactions can be established within the

[163] Bonneville Power Administration, BPA's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 8 presentation (July 18, 2004), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-8-presentation.pdf.

[164] Service Flow Constraints are intended to represent a commercial constraint that manages market flows attributed to the market, not total flow expressed as a mega-watt (MW) value.

[165] SPP Markets+ Tariff, Attach. D § 1.2 (Obligation to Communicate Markets+ Transmission Capacity Availability Changes).

[166] Markets+ TSPs/BAs will need to develop their own opt-out process with its transmission customers that will ultimately feed into the Markets+ opt-out process. SPP Markets+ Protocol, 8.2.2 Markets+ Transmission Capacity Opt-Outs and Exhibit 8-2: Transmission Opt-Out and Congestion Rent Process Timeline.

[167] SPP Markets+ Tariff, Attach. C § 4.5 (Monitoring for Potential Transmission Market Power Activities)

market using an e-tag. [168] The market will incorporate the additional load obligation (for an export) or generation injection (for an import) within the optimization. Markets+ also allows for price-sensitive bidding at the market footprint in the day-ahead optimization, which requires an e-tag as well.

As the region moves towards participation in a day-ahead market, Bonneville understands that utilities, which may also be Bonneville transmission contract holders, are making their own independent market participation decisions and may want to use their Bonneville transmission rights in those markets. As a result, regardless of Bonneville's decision to join a day-ahead market, Bonneville may need to reflect tariff revisions and/or business practice updates to clarify the requirements for transmission customers to use their transmission rights for their respective market participation.

Bonneville will need to address necessary tariff changes for implementation. Bonneville will discuss potential tariff changes through the tariff process. Bonneville may also need to update its business practices for implementation and will do so through the established business practice process.

6.8.1. Transmission Product Availability

As discussed previously, Bonneville does not expect the general transmission products or terms and conditions to change due to Bonneville joining Markets+. However, joining Markets+ will impact the reservation and scheduling timelines of its short-term products, specifically, the hourly firm, hourly non-firm, and non-firm secondary products. Currently, Bonneville's hourly firm transmission window opens at 9 a.m. Pacific Time of the WECC preschedule day, and non-firm window for hourly and secondary products opens at 10 a.m. of the WECC preschedule day.[169] These transmission windows will need to be evaluated because the availability of these short-term products will need to conform to the day-ahead market timelines for the day-ahead (e.g., 10 a.m. deadline for the day-ahead market clearing process to start and initial RUC) and real-time horizons (e.g., intra-day RUC and T-30 for each operating hour), in order to afford customers enough time to buy transmission and meet market deadlines. Transmission customers in WECC are accustomed to navigating TSP timing windows for reserving transmission, not just Bonneville's, which vary and may be set in different time zones. Understanding the updated TSP timing windows for reserving transmission for day-ahead markets will be another consideration to navigate in the near future.

In addition, participating TSPs are required to pause processing of TSRs in the queue for the next operating day during the day-ahead market clearing process (approximately from 10 a.m. to 1:30 p.m. Pacific Time on day-ahead) so the market optimization has a static set of transmission constraints to develop the market solutions. While the queue is paused, transmission customers will have the ability to submit TSRs but those TSRs will remain in the queue in queue order. Once the market operator posts the awards associated with the market solutions and the TSPs have accounted for any incremental transmission used by the market, TSPs will resume processing TSRs in the queue.

As noted above, Bonneville understands that it will have transmission customers that may wish to use their Bonneville transmission rights for transactions/schedules that source or sink outside the BAA or for wheeling across the BAA, including for optimization in another market (e.g., EDAM). Bonneville will need to address how it will make its transmission available for use in other markets, as well as implementation of the reservation timelines in a future tariff proceeding and, as necessary, through the business practice process.

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[168] E-tags are used to schedule power transactions that include who is supplying the power, how much power (expressed as MWs), timeframe, purchasing/selling entities involved, BAAs involved, the transmission paths, and who is receiving the power.

[169] Bonneville Power Administration, Requesting Transmission Service Business Practice V.47 § C.1 (Jan. 22, 2024), *available at* https://www.bpa.gov/-/media/Aep/transmission/business-practices/tbp/requesting-transmission-service-bp.pdf.

6.8.2. *Transmission Losses*

As energy is physically delivered across a transmission system, there is a natural degradation or "loss" that occurs because of physical factors such as distance and the overall loading of transmission facilities. Transmission losses represent additional physical generation that is necessary to make up the difference between a scheduled amount of energy from a generator and what is "lost" on the way to serving a load. Bonneville currently requires transmission customers to either designate to return transmission losses in kind (e.g., with a physical delivery of energy concurrently) or settle them financially.

In joining the WEIM, Bonneville did not need to make significant adjustments to the provision of losses because the majority of losses still occurred outside of the market (associated with the base schedules submitted ahead of the market). However, for the WEIM, Bonneville elected the "donation model" of Transmission Rights by Interchange Rights Holders[170] to be used for WEIM transfers that source or sink in the Bonneville BAA. The donation of these transmission rights into WEIM does not eliminate the transmission loss obligation of the Interchange Rights Holders, yet to avoid "double-payment," Bonneville exempted loss returns for WEIM transfers using Bonneville transmission during WEIM participation because the market accounts for losses associated with incremental market transfers within the optimization.

In Markets+, both the day-ahead and real-time optimizations procure sufficient energy to serve losses across the market footprint. Transmission losses for both the day-ahead awards and the incremental real-time dispatches are settled financially by the market and reflected in the LMP. Bonneville will discuss with stakeholders the extent to which Markets+ may lead to changes in Bonneville's current policies regarding transmission losses. Specifically, Bonneville will need to focus on two areas: 1) transmission that is not available to the market, and 2) transactions/schedules that use Bonneville transmission but source or sink outside the Markets+ footprint. Bonneville will address these details in applicable rates, tariff or business practice proceedings.

7. NEPA & Environmental Obligations

Consistent with NEPA, 42 U.S.C. § 4321 et seq., Bonneville is in the process of assessing the potential environmental effects that could result from the proposed participation in a day-ahead market. Bonneville believes this proposal appears to be the type of action typically excluded from further NEPA review pursuant to U.S. Department of Energy NEPA regulations, which apply to Bonneville. However, Bonneville will consider all public comments concerning NEPA compliance and/or potential environmental effects of the proposal that Bonneville received during the public discussions for this proposal.

8. Tribal Obligations

The Day-Ahead Market Policy does not impact tribal treaty rights or resources. First, the Policy is a decision on a policy direction, it is not a binding implementation decision to join Markets+. Any decision to join a day-ahead market will be made after further consideration. Second, any future DAM participation will not change Bonneville's ability to meet obligations under existing laws and contracts, including FCRPS operations, river management, or fish and wildlife mitigation. As discussed in section 6.1.1, Bonneville can communicate various operational constraints for its generators as part of its market offers in order to meet both power and non-power obligations, and will continue to prioritize meeting all obligations. Therefore, this Policy does not impact Bonneville's tribal treaty or general trust responsibilities.

9. Conclusion and Next Steps

The preceding Day-Ahead Market Policy represents an extensive analysis of the options available to Bonneville in

[170] Bonneville Power Administration, Energy Imbalance Market (EIM) Business Practice V.5 § J.

response to the developments of day-ahead markets in the West. Bonneville examined the market designs of both EDAM and Markets+ with a particular focus on the elements pertaining to governance and stakeholder process; RA and resource sufficiency; price formation and market power mitigation; transmission and congestion rent; and GHG accounting. Additionally, Bonneville has carefully considered the operational complexities, implementation challenges, and potential for sunk costs presented by each market option. The results of this analysis have been weighed against each of Bonneville's day-ahead market participation principles. Throughout this analysis, Bonneville has held a series of 11 public workshops to provide transparency into Bonneville's evaluation, responses to comments received, day-ahead market offerings, Pathways, and impacts to various aspects of Bonneville's business and products.

Governance has specifically been a central factor in Bonneville's evaluation. Markets+ successfully developed and implemented a governance structure that met Bonneville's criteria. In the meantime, Pathways performed significant work to develop recommendations to improve independence of the governance of the CAISO-run WEIM and EDAM markets. To date, its recommendations have resulted in an approved future transition to primary authority for the independent WEM Governing Body. Several entities have requested that Bonneville delay its day-ahead market decision until the end of 2025 to allow more time for the California legislature to act on proposed legislation to move the Pathways vision forward and for the governance model to continue to evolve towards full independence. While Bonneville applauds the considerable work done by Pathways, its recommendations do not enable the level of independence that is offered by Markets+. The legislation that has been introduced would confirm this limited scope of independence. For that reason, Bonneville does not see benefit in waiting for California's legislative consideration.

The Pathways Step 2 proposal suggested future considerations to expand the independence, and the market services offered. Those subsequent steps to greater independence would be incremental and subject to further studies and likely further legislative authorization. Ultimately, Bonneville prefers the stakeholder-driven governance structure of Markets+. Bonneville contends that the Markets+ development has resulted in a superior market design that is available today and believes it will remain a durable, equitable form of governance in the future.

Bonneville's analysis presented complex results regarding each day-ahead market option, including the status quo. The PCM studies showed a wide range of potential economic outcomes, including meaningful trends that joining EDAM could yield a greater financial benefit for Bonneville and that joining Markets+ has potential for significant monetary benefits under multiple scenarios. It is important to note that these results are not due to differences in market design but are driven from higher prices that come with being in a market with California and the connectivity offered by the current expected EDAM footprint. In almost every scenario, this potential greater monetary benefit was dependent on the assumption that Bonneville would continue to enjoy surplus generation, which adds uncertainty to the results as Bonneville's load and generation forecasts demonstrate a potential erosion of its surplus generation over time. As demonstrated, the benefits in the expected Markets+ footprint improved as hurdle rates were reduced, closing the gap between EDAM and Markets+ benefits and resulting in benefits above BAU.

Additionally, PCMs do not account for market design features, such as congestion rent, market power mitigation, and price formation, that can significantly impact monetary benefits realized from a day-ahead market. These design features are discussed in detail in this analysis and Bonneville believes the Markets+ design is likely to provide economic benefits to Bonneville and our customers through these features that at least partially offset the EDAM benefits estimated in the PCM studies. These design features in Markets+ were all constructed via an inclusive stakeholder process that should result in these market design features accounting for unique needs of market participants, and Bonneville is confident that the Markets+ stakeholder process will be responsive to requests to revisit these design elements if unexpected or unsatisfactory results are realized once the market is live. Bonneville has determined that the trends toward greater potential monetary benefits under the previously discussed assumptions and caveats in EDAM and in the short term for status quo do not outweigh the strategic benefits and superior market design presented with Markets+.

The option of Bonneville remaining only in the WEIM while its neighbors join day-ahead markets was an option that Bonneville carefully considered, and one that the PCM results showed could bring significant monetary benefit. While Bonneville agrees this option shows short term appeal, Bonneville continues to have significant concerns about the long-term viability of this option due to the operational and economic risks, such as reduced liquidity in the bilateral market, that accompany this option. Remaining in WEIM would likely foreclose the option to join Markets+, leaving EDAM as the only day-ahead market option for Bonneville should it choose to pursue day-ahead participation in the future. Because the Pathways Step 2 proposal does not achieve desired independence, and legislation remains speculative, this option carries significant strategic risk. Other important elements that Bonneville examined in this process are the market seams and the potential operational complexities that will be present with multiple markets in the Pacific Northwest. Bonneville acknowledges that a single market in the Northwest would be operationally simpler, but the decisions of Bonneville's neighboring BAAs suggest that two markets are likely to operate in the Pacific Northwest. The presence of these challenges should not prevent Bonneville from joining a market with superior design and independence. Bonneville places great importance on its operational and reliability responsibilities in the region and stands ready to work with the entities in EDAM and within the region to collaboratively resolve these jointly owned issues.

Throughout this evaluation process, Bonneville has experienced the powerful impact of competition in motivating both SPP and CAISO to significantly improve market offerings in order to attract participants. Without this competition, Bonneville believes many of the creative market design solutions benefitting consumers that both market operators are pursuing may have never materialized. Bonneville also believes many of the changes contemplated and implemented in the CAISO governance and stakeholder processes and the recent urgency with which they have been pursued are a direct result of competition from another market operator. These CAISO initiatives are resulting in an improved market for entities that have or may choose EDAM participation. The continuation of this competition benefits Bonneville, its customers and all consumers in the west regardless of market participation choices by maintaining pressure on market operators to continue innovating and improving.

After thorough evaluation, analysis, and weighing of its participation principles, as well as the governance, market design, and strategic benefits presented by Markets+, Bonneville has concluded that its participation in Markets+ is the best long-term strategic direction for Bonneville, its customers, and the Northwest.

Bonneville would like to express profound appreciation for those who have engaged in the public process and provided insights to make this a robust, transparent, and effective evaluation of its potential participation in a day-ahead market. Bonneville looks forward to ongoing public review and input as implementation details are developed. Bonneville will be developing a stakeholder engagement plan to provide market design updates and technical implementation that will incorporate customer input. Bonneville will be utilizing the '6-step process' as a way to collaborate with customers on the policy issues through the tariff and rates proceedings.

Appendix A

Legal Assessment

1. Legal Authority to Join Markets+

Bonneville's decision to join any market must comport with multiple grants of authority, including, but not limited to, power marketing, providing transmission service, and operating in a business-like manner. In exercising such authorities, the Administrator must balance his ability to meet multiple statutory obligations, such as providing preference and priority in the sale of power when there are conflicting or competing requests, making firm power sales under section 5(b) of the Northwest Power Act, providing transmission service and operating the transmission system, setting rates sufficient to repay the federal investment, and fulfilling environment, fish and wildlife obligations. This legal assessment describes how Bonneville could meet these obligations while participating in Markets+. At a high-level, Bonneville would join Markets+ by agreeing to a set of contracts incorporating a day-ahead market tariff.

Bonneville would exercise its contracting authority under section 2(f) of the Bonneville Project Act[171] to agree to a day-ahead market tariff. This would be similar to actions Bonneville has taken to participate in WEIM and WRAP.[172] Similar to the WEIM and WRAP agreements, and like any contract with a market operator implementing a day-ahead market subject to an applicable tariff, an agreement to participate in a day-ahead market must expressly acknowledge and not infringe upon Bonneville's authority to meet its statutory obligations and contractual requirements. Based on the day-ahead market tariff offerings to date, Bonneville has not identified legal barriers to satisfying its statutory obligations while participating in a day-ahead market.

Bonneville has the business flexibility to participate in a day-ahead market.

Since its inception, Congress has imbued Bonneville with broad statutory authority to market the power produced by federal hydropower generating projects. In the Bonneville Project Act of 1937, Congress granted Bonneville broad contracting authority for the specific purpose of allowing Bonneville to operate like a business in the marketing of federal power.[173] As the designated "marketing agent" for all electric power generated by the Federal Columbia River Power System,[174] Bonneville's statutes are unique with repeated focus on the business-related aspects of the agency's authority.

Both Congress and the courts have reaffirmed Bonneville's authority to operate in a businesslike manner. As summarized in a 1977 Senate Report:

> [The] legislative history [of the statutes governing Bonneville's operations] reflects a congressional recognition of the significant role played by [Bonneville] in the Pacific Northwest, and an effort to enable this organization to operate in a businesslike fashion and to free it from the requirements and restrictions ordinarily applicable to the conduct of Government business. The transfer of the functions of [Bonneville] from the Department

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[171] 16 U.S.C. § 832a(f).

[172] Bonneville Power Administration, Energy Imbalance Market Policy, Administrator's Record of Decision at 54-56 (Sept. 2019) (WEIM Policy ROD), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalancemarket/rod-20190926-energy-imbalance-market-policy.pdf; Bonneville Power Administration, Bonneville's decision to participate in the Western Resource Adequacy Program Phase 3B (Dec. 16, 2022), *available at* https://www.bpa.gov/-/media/Aep/projects/resource-adequacy/wrap-final-closeout-letter.pdf.

[173] Bonneville Project Act, 16 U.S.C. § 832a(f); *see* S. Rep. No. 79-469, at 13 (1945) ("[BPA] operates a business enterprise . . . .") (letter from Interior Secretary Ickes).

[174] Transmission System Act of 1974 § 8, 16 U.S.C. § 838f.

> of the Interior to the Department of Energy is not intended to diminish in any way the authority or flexibility which is a requisite to the efficient management of a utility business.[175]

The ability of Bonneville to adapt to the ever-changing landscape of the wholesale electric power industry like a business is particularly important because the Administrator must implement many, and often competing, statutory directives.[176] Similarly, the U.S. Court of Appeals for the Ninth Circuit has noted that "[The Administrator] must continue to run [Bonneville] like a business on a sound financial basis, enabling it to repay its debt to the federal treasury in a timely fashion, while discharging costly new public duties assumed after the Northwest Power Act's passage."[177]

In 1995, Bonneville adopted a Business Plan with a market-driven direction and a goal to be a more active participant in the competitive market for power, transmission, and energy services.[178] As stated in the 1995 Business Plan Record of Decision, Bonneville's objective is to use its success in markets to ensure the financial strength necessary to better produce the public benefits that Bonneville affords to the region.[179] The market-driven approach is designed to increase the value of Bonneville's business and generate expanded benefits to share with customers and constituents-including energy conservation and fish and wildlife mitigation.[180] By evaluating potential participation in a day-ahead market, Bonneville is continuing its long-standing business strategy to pursue options that could produce value for Bonneville's customers and the region.

This Policy discusses how Bonneville and the region as a whole are experiencing significant and unprecedented changes in the industry. Faced with competitive drivers and new regulatory requirements, electric utilities are devoting significant resources to develop and transition to market-based solutions that aim to reduce inefficiencies, improve power and transmission system reliability, lower production costs, and bolster resource adequacy, among other things. Bonneville and other utilities' participation in the Western Energy Imbalance Market are an example of one such development. These new competitive drivers are creating opportunities for Bonneville to modernize its business to preserve and enhance the value Bonneville provides to its customers pursuant to its statutory mission.

As Bonneville evaluates potential participation in a day-ahead market, some of its key objectives rooted in statute are to ensure an adequate, efficient, economical, and reliable power supply, and to encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles. Therefore, Bonneville continues to assess whether participation would provide value for customers in terms of greater efficiency, lower costs, and increased reliability.[181]

2. Bonneville would fulfill its preference obligations and Northwest Power Act Section 5(b) firm power sales obligations while participating in a day-ahead market.

Bonneville's authority to market federal power is included in several statutes: the Bonneville Project Act

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[175] S. Rep. No. 95-164, at 30 (1977), reprinted in 1977 U.S.C.C.A.N. 854, 884.
[176] *Ass'n of Pub. Agency Customers v. Bonneville Power Admin.*, 126 F.3d 1158, 1170-71 (9th Cir. 1997).
[177] *Id*.
[178] Bonneville Power Administration, Business Plan Record of Decision (Aug. 15, 1995), *available at* https://www.bpa.gov/-/media/Aep/about/publications/records-of-decision/1995-rod/rod-19950815-business-plan-final-environmental-impact-statement.pdf.
[179] *Id.* at 1.
[180] *Id.* at 11.
[181] Bonneville Power Administration, Staff Recommendation on Day-Ahead Market Participation at 2-3 (Apr. 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/02-day-ahead-market-attachment-1-staff-recommendation.pdf.

of 1937, the Flood Control Act of 1944, the Pacific Northwest Consumer Power Preference Act of 1964, the Federal Columbia River Transmission System Act of 1974, and the Pacific Northwest Power Planning and Conservation Act of 1980. Collectively, these statutes form the basis for Bonneville's broad authority to market power. For Bonneville to participate in Markets+, it must market power consistent with these statutory authorities.

Bonneville recognizes that many stakeholders have requested explanations of how Bonneville will meet obligations in these statutes to provide public bodies and cooperatives preference and priority to federal power, and to offer contracts for the sale of electric power under section 5(b) of the Northwest Power Act, considering the paradigm shift that a day-ahead market would represent. As explained below, Bonneville will continue to meet its preference and section 5(b) obligations included in these authorities if it participates in a day-ahead market.

a. Bonneville must provide preference in sales of power at all times in the event of competing or conflicting applications for power.

Bonneville will continue to provide preference in the sale of power to public bodies and cooperatives in the event of competing applications. Bonneville would continue to offer long-term power sales contracts to 5(b) customers and would incorporate the day-ahead market dispatch framework into the contract terms and rates for such sales. Section 4(a) of the Bonneville Project Act of 1937 specifies, "[i]n order to insure that the facilities for the generation of electric energy at the Bonneville project shall be operated for the benefit of the general public, and particularly of domestic and rural customers, the administrator shall at all times, in disposing of electric energy generated at said project, give preference and priority to public bodies and cooperatives."[182] Section 4(b) further explains, "in the event that . . . there shall be conflicting or competing applications for an allocation of electric energy between any public body or cooperative on the one hand and a private agency of any character on the other, the application of such public body or cooperative shall be granted."[183] The Flood Control Act of 1944 similarly states that "[p]reference in the sale of such power and energy shall be given to public bodies and cooperatives."[184] Thus, Bonneville's earliest legislation established the foundational principle that Bonneville shall afford preference to public bodies and cooperatives in the event of competing or conflicting requests for power. Bonneville understands that providing preference in the event of competing applications is a fundamental component of its power marketing obligation that it will continue to meet if it chooses to participate in Markets+ for the benefit of its customers.

Section 5(a) of the Northwest Power Act reaffirms the preference and priority provisions from Bonneville Project Act by stating, "[a]ll power sales under this chapter shall be subject at all times to the preference and priority provisions of the Bonneville Project Act of 1937 . . . ."[185] The Northwest Power Act was enacted to resolve regional power customer fears about an impending allocation of low-cost Federal power. The House Report of the Commerce Committee on the Northwest Power Act emphasized that sales by the Administrator would be subject to existing preference provisions:

> The purpose of this provision is clear. The Committee wants to ensure that all preference customer contract requirements will continue to have a priority over sale to other customers

[182] 16 U.S.C. § 832c(a).

[183] 16 U.S.C. § 832c(b); *see also Aluminum Co. of Am. v. Cent. Lincoln People's Util. Dist.*, 467 U.S. 380, 393 (1984) ("[T]he preference system merely determines the priority of different customers when the Administrator receives 'conflicting or competing' applications for power that the Administrator is authorized to allocate administratively." (citing section 4(b) of the Bonneville Project Act)).

[184] 16 U.S.C. § 825s.

[185] 16 U.S.C § 839c(a)

> and other sales would be, in effect, subordinate to preference provisions of the Bonneville Project Act, including the 5-year withdrawal features for contracts with non-preference customers and the 20-year limitation on the terms of the contract.[186]

Bonneville finds that it will be able to continue to satisfy preference when there is a competing or conflicting application for power in a day-ahead market. As described above, in a day-ahead market context, Bonneville would continue to make long-term forward sales of power and would apply preference if faced with a limited supply of power. After the day-ahead market clears, any out-of-market requests for electric power from Bonneville are likely to fall within the context of a surplus sale. Bonneville would continue to meet its preference obligations for both long-term sales and surplus sales as described below.

b. Bonneville is authorized to acquire resources to meet all eligible customer requests for electric power under section 5(b) of the Northwest Power Act.

Bonneville's acquisition authority generally ensures that Bonneville can acquire to meet the needs of all customers requesting contracts for electric power and thereby avoid a preference allocation among competing or conflicting requests for power. Historically, there was no need for Bonneville to apply preference because Bonneville had an abundance of power. However, in the 1970s, projections showed that because of increased power demand, the Administrator would be required to apply preference and allocate the limited amount of federal power. Upon expiration of the power sales contracts with non-preference customers, the Administrator would no longer be able to sell power to non-preference entities because the preference clauses would obligate him to allocate the limited supply to public bodies and cooperatives. Congress drafted the Northwest Power Act to prevent the need for an allocation of power.[187] The Act solved the pending allocation and reduces the potential application of preference in the future by providing the Administrator with resource acquisition authority to meet his sales obligation.

Section 5(b)(1) of the Northwest Power Act provides,

> Whenever requested, the Administrator shall offer to sell to each requesting public body and cooperative entitled to preference and priority under the Bonneville Project Act of 1937 . . . and to each requesting investor-owned utility electric power to meet the firm power load of such public body, cooperative or investor-owned utility in the Region to the extent that such firm power load exceeds [customer resources].[188]

Section 5(b) thus establishes the Administrator's obligation to offer a contract for the sale of electric power to meet the firm power loads of any requesting regional public body, cooperative, or investor-owned utility in excess of non-federal resources used by the customer to serve such load. The Act not only requires the Administrator to offer a contract for the sale of electric power to all eligible requesting customers but also directed the Administrator to offer new power sales contracts to then-existing direct service industry customers.

To implement the Act in a timely matter, Congress deemed the Administrator to have sufficient resources and, most importantly, granted the Administrator authority to acquire resources to meet Bonneville's long-term power supply obligations. In sections 6(b), (c), and (d) of the Northwest Power Act, Congress granted

[186] H.R. Rep. No. 97-976, Pt. I, at 34 (1980).

[187] As the Supreme Court has explained, "Congress moved to avert what appeared to be an emerging customer struggle for [Bonneville] power by enacting the [Northwest Power Act]." *Aluminum Co. of Am.*, 467 U.S. at 383. And as Congressman Swift remarked, "[t]he basic concept of this bill is simple: It permits BPA to avoid the need for an administrative reallocation of power by giving BPA the means to reduce loads and to acquire resources so that it should be able to meet the needs of all classes of customers . . . . This is a bill to solve a power allocation problem . . . ." 126 Cong. Rec. H27818 (daily ed. Sept. 29, 1980) (remarks of Rep. Swift).

[188] 16 U.S.C. § 839c(b).

Bonneville the authority to acquire resources to meet his long-term power supply obligations.[189] It is important to note that while section 5(b) requires the Administrator to supply the power requirements of all requesting public and investor-owned utility customers and to acquire resources when necessary, Congress also provided protections for preference customer rates when establishing rates pursuant to section 7(b).[190]

Importantly, section 5(b) contracts are not a response to "competing or conflicting" requests for power that would require an allocation of electric energy. The section 5(b) sales obligation operates in conjunction with long term loads and resource planning and the section 6 resource acquisition authority so that, in general, Bonneville does not need to allocate power among conflicting or competing applications. When a customer has a long-term power sales contract, they receive power under that contract and preference is not triggered.

While the obligation remains of paramount importance, preference only triggers if Bonneville is unable to acquire resources to satisfy its 5(b) obligations due to an insufficiency of resources or if Bonneville is offering to sell surplus electric power. The insufficiency and surplus scenarios are discussed in the following two sections.

c. Bonneville must apply preference in an allocation scenario.

In a scenario where Bonneville is faced with a limited supply of power in the planning horizon, preference would apply. In general, section 6 of the Northwest Power Act provides Bonneville with acquisition authority designed to ensure he can meet all requests for power. Section 11(b)(6) of the Transmission System Act also provides Bonneville with the authority to purchase electric power on a short-term basis to meet temporary deficiencies in power it is obligated to supply.[191]

Bonneville's ability to acquire power to meet its supply obligations generally avoids Bonneville having a limited amount of power that must be allocated through the operation of preference. Northwest Power Act section 5(b)(5) requires the Administrator to provide contractual mechanisms to apply preference in the unlikely event that Bonneville cannot acquire resources to meet its power supply obligations.[192] If the Administrator "cannot be assured on a planning basis of acquiring sufficient resources to meet such loads during a specified period of insufficiency" he is obligated to apply preference and allocate electric energy among customers in accordance with the section 5(b)(6) allocation provisions.[193]

If Bonneville were to determine that it cannot be assured on a planning basis to meet its long-term firm power sales, Bonneville would allocate power based upon the insufficiency and allocation methodology.[194]

Additionally, Bonneville's participation in a day-ahead market is likely to substantially mitigate the risk of an insufficiency. Bonneville will maintain its existing Resource Program, which incorporates guidance from Northwest Power and Conservation Council's Power Plan; continue to plan its resources on an annual, monthly, daily, and real-time basis to assure a firm power supply to meet its firm power sales obligations; and participate in WRAP. In the long term, day-ahead markets should lead to improved regional resource planning. Markets+ requires each participant, including Bonneville, to demonstrate a commitment that it has sufficient resources available to meet its forecast load obligations in the planning horizon by participating in the WRAP. Based on Bonneville's continued efforts and the benefits that coordination

[189] 16 U.S.C. § 839d(b)-(d).
[190] 16 U.S.C. § 839e(a)-(b).
[191] 16 U.S.C. § 838i(b)(6).
[192] 16 U.S.C. § 839c(b)(5).
[193] *Id.*; 16 U.S.C. § 839c(b)(6).
[194] *See* Notice of Publication of the Insufficiency and Allocations Exhibit for the Power Sales Contract, 61 Fed. Reg 11,389 (Mar. 20, 1996).

through a market will bring, there will be an even lower chance that Bonneville would be required to allocate power based on a projected insufficiency on a planning basis.

d. Bonneville will apply preference for competing and conflicting applications for surplus power.

The most common application of statutory preference is when Bonneville offers to make a surplus power sale. The Bonneville Project Act of 1937[195] and the Pacific Northwest Consumer Power Preference Act of 1964[196] specify the application of statutory preference when Bonneville markets surplus power. The Regional Preference Act specifies that, in the event of competing applications for available surplus power, and terms and conditions are mutually agreed upon, Bonneville will meet customer requests in the following order: 1) Pacific Northwest public utilities, 2) Pacific Northwest investor-owned utilities and direct-service industrial customers, and 3) Southwest public utilities. Thereafter, if additional power is available, Bonneville may also make surplus sales to non-preference customers.

In the Western Energy Imbalance Market Policy Record of Decision, Bonneville explained the specific mechanics of the notice of surplus power. Consistent with that analysis, in a day-ahead market, Bonneville intends to continue the regional notice format the agency has used for over 20 years.[197] Since the advent of modern markets, Bonneville has provided notice to its preference customers regarding the availability of short-term surplus power using a combination of: (1) annual letters providing notice of surplus availability and how regional customers may exercise their rights; (2) product specific letters/emails when Bonneville is preparing to sell a new type of product to a non-preference customer; and (3) a standing daily notification on Bonneville's website regarding the availability of surplus power and instructing regional customers on how to obtain it if they are interested. Bonneville is unaware of any instance during the past 20 years where regional preference customers took issue with the format of Bonneville's notice requirements. This format has been an efficient and effective way for Bonneville to participate in the short-term market while also notifying regional customers that Bonneville may have surplus power available for sale on a rolling basis.[198]

When Bonneville began to participate in the Western Energy Imbalance Market, it updated its daily standing notice to specify that, if surplus remains available prior to the market run, Bonneville may bid such surplus power into the market at its discretion. In a day-ahead market, Bonneville would follow the same approach. The agency would continue to provide public preference and Pacific Northwest regional preference to requests for surplus power before and after the day-ahead market run. Bonneville would continue to welcome customer inquiries regarding potential purchases of surplus power before and after the day-ahead market submission timeframe.

Similarly, Bonneville's participation in a day-ahead market will not impact its surplus sales approach. Bonneville will continue to market surplus power when available, prior to the day-ahead market generation and load bid submission window, and thereafter prior to the real-time market bid submission window. The day-ahead market resource schedule output does not ultimately determine real-time dispatch, the real-time market bid submission window allows for Bonneville to make additional sales if surplus power remains available. Bonneville will continue to meet its regional preference obligations when marketing uncommitted surplus power.

For the reasons described above, Bonneville's legal assessment is that it can participate in a day-ahead market consistent with its preference obligations, 5(b) firm power sales obligation, obligations to allocate power consistent with preference in the event of insufficiency, and obligations to provide preference when

[195] 16 U.S.C. § 832 *et seq.*
[196] 16 U.S.C. § 837 *et seq.*
[197] WEIM Policy ROD at 62.
[198] *Id.*

making surplus sales.

3. Day-ahead market participation would be akin to an interregional exchange of power.

Since the enactment of the Bonneville Project in 1937 through the passage of the Pacific Northwest Electric Power Planning and Conservation Act in 1981, Congress contemplated and included within the scope of the Administrator's authorities the authority to interconnect with power systems both within and outside the Pacific Northwest region and leverage these interconnections to make mutually beneficial interregional exchanges. For example, section 2(b) of the Bonneville Project provides:

> In order to encourage the widest possible use of all electric energy that can be generated and marketed and to provide reasonable outlets therefor, and to prevent the monopolization thereof by limited groups, the administrator is authorized and directed to provide, construct, operate, maintain, and improve such electric transmission lines and substations, and facilities and structures appurtenant thereto, as he finds necessary, desirable, or appropriate for the purpose of transmitting electric energy, available for sale, from the Bonneville project to existing and potential markets, and, *for the purpose of interchange of electric energy, to interconnect the Bonneville project with other Federal project and public owned power systems* constructed on or after August 20, 1937.[199]

The Northwest Power Act also includes provisions promoting interregional exchanges. Section 6(l)(1) provides:

> The Administrator is authorized and directed to investigate opportunities for adding to the region's resources or reducing the region's power costs through the accelerated or cooperative development of resources located outside the States of Idaho, Montana, Oregon, and Washington if such resources are renewable resources, and are now or in the future planned or considered for eventual development by nonregional agencies or authorities that will or would own, sponsor, or otherwise develop them.[200]

Section 6(l)(2) further provides:

> The Administrator is authorized and directed to investigate periodically opportunities for mutually beneficial interregional exchanges of electric power that reduce the need for additional generation or generating capacity in the Pacific Northwest and the regions with which such exchanges may occur.[201]

Congress understood that interregional transmission interties between the Pacific Northwest and adjoining regions, such as the Pacific Northwest Pacific Southwest Intertie, offer substantial benefits. At the time of the enactment of the Northwest Power Act, existing transactions reduced the need for new generating capacity, helped provide more reliable service to load, reduced the need to rely on fossil fueled resources, and reduced the costs of electricity. In a June 1981 report on Interregional Resource Potentials, Bonneville committed to continuing to work with entities in the region and adjoining regions to optimize the use of existing generating facilities and reduce the need for new generating facilities through mutually beneficial exchanges and other transactions.

Bonneville has a longstanding definition of interchange energy in the power marketing context.[202] Interchange energy means energy received by one utility system from another, usually in exchange for

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[199] 16 U.S.C. § 832a(b) (emphasis added).
[200] 16 U.S.C. § 839d(l)(1).
[201] 16 U.S.C. § 839d(l)(2).
[202] *See* Bonneville Definitions (1993).

energy delivered to the other utility at another time or place. It is distinguished from a direct purchase or sale, although accumulated energy balances are sometimes settled in cash. Through interchange and interconnection, Bonneville has been able to enter into power-for-power exchanges, including some with payments of money incidental to the power that were justified as a suitable exchange term. Indeed, exchanges need not be simultaneous and the places where an exchange occurs may vary.

A day-ahead market will operate similar to an exchange of power because all market participants must bring sufficient resources to the market to serve their loads, which is designed to prevent participants from leaning on other participants. Rather than a bilateral exchange of power, power exchanged in the market will flow among the participants to make the most economical use of the transmission system. Thus, the power available under a day-ahead market is in effect exchanged between and among the participants resulting in all participants maintaining their load and resource balance. Here, Bonneville's participation in the interregional Markets+ day-ahead market falls within the scope of the section 6(l) directives to investigate such markets and the resources exchanged therein, including to increase supplies of electric power produced by renewable resources.

4. **Bonneville policies will ensure that section 5(b) customers receive power with environmental attributes reflecting the system resource mix.**

Bonneville's preference customers have requested acknowledgement of the inherent value of the low-carbon resources from which Bonneville supplies power. Bonneville committed in its Provider of Choice Policy to convey the environmental attributes of the power sold, including emissions and any Renewable Energy Certificates commensurate with a customer's firm power purchase amount and rate elections. Bonneville believes it is reasonable to conclude that these non-power characteristics should accompany Bonneville's physical sales of power. Bonneville's objective as an active participant in developing the day-ahead market GHGs framework designs has been to ensure that it can uphold its policy that non-power characteristics will accompany Bonneville's sales of power.

Bonneville markets power from the system mix of federal and non-federal resources, and this will not change in a day-ahead market. While some jurisdictions have concluded that environmental attributes are associated with power, such environmental attributes are defined through variously differing state laws and local regulations and are subject to change and are not applicable to Bonneville. Nevertheless, Bonneville believes a policy consideration regarding participation in a day-ahead market is whether the market rules support conveyance of environmental attributes associated with sales of power to Bonneville's public customers. Bonneville finds the Markets+ Tariff to meet its policy objectives notes that many of Bonneville's public power customers also support its greenhouse emissions accounting mechanisms. Bonneville will continue to work with its customers, and in the appropriate market design forums, as work on GHG accounting continues.

5. **Bonneville would participate in a day-ahead market consistent with its authorities to provide transmission service and operate the transmission system.**

Bonneville has broad authority under its governing statutes to set the terms and conditions of transmission service, as well as how to operate the system in order to provide transmission service and maintain reliability.[203] While participating in Markets+, Bonneville will continue to offer transmission service and Ancillary and Control Area Services under its OATT, which ensures that Bonneville and its customers take transmission service on a comparable basis. Bonneville will also be able to make transmission available for

[203] *See Cal. Energy Comm'n v. Bonneville Power Admin.,* 909 F.2d 1298, 1314 n.17 (9th Cir. 1990) (holding that the Administrator's authority to operate the transmission system "is broad, allowing the Administrator substantial discretion" and that "[t]his discretion is tempered only by the implied limitation that the Administrator's action not be inconsistent with other congressional decrees.").

market use, which is authorized under section 2(b) of the Bonneville Project Act.[204]

Joining a day-ahead market will require that transmission be made available for market use. Making transmission available for day-ahead market use falls within Bonneville's broad transmission authorities. Bonneville is monitoring day-ahead market policies to ensure benefits to transmission rights holders including through congestion rent policies, and to ensure compensation for any lost transmission sales through market transmission use charges. In addition, Bonneville will work through issues presented by entities holding transmission rights on the Bonneville system that want to participate in various day-ahead markets, as well as with Bonneville customers in other balancing authority areas that may be affected by a transmission provider's market participation.

6. Congress granted federal utilities authority to join transmission organizations.

In the Energy Policy Act of 2005 (EPAct '05), Congress provided authority for federal utilities, including power marketing administrations, to participate in transmission organizations, such as RTOs, consistent with their existing statutory authorities, obligations, and limitations.[205] When considering EPAct '05, the House Committee on Energy and Commerce, Subcommittee on Energy and Air Quality discussed the economic dispatch associated with organized markets and its potential benefits for fostering competitive electric markets and ultimately reducing costs to the consumer.

By 2005, RTO and ISO market designs had matured significantly since deregulation formally began in 1996.[206] RTOs had formed in many parts of the country and some included day-ahead and real-time energy markets based upon economic dispatch. Congress enacted the EPAct '05 with awareness of the context of evolving electricity markets, including Federal Energy Regulatory Commission Order No. 2000 regarding RTOs, which FERC Commissioner Bromwell explicitly discussed in her House committee testimony regarding the bill. Commissioner Bromwell explained that "RTOs that are fully independent of market participants can ensure non-discriminatory operation of the transmission facilities under their control. RTOs have FERC-approved market monitors, implement FERC-approved market mitigation plans, and conduct long-range planning all for the protection of customers. RTOs can perform economic dispatch over large geographic areas that will ensure the selection of least-cost generators. Finally, RTOs can offer organized markets and one-stop shopping that reduce transaction costs, provide transparent market rules and allow the opportunity for price discovery." [207]

Consistent with this sentiment, Bonneville views its EPAct '05 authority and Congress's understanding of organized markets as informative for its consideration of whether to participate in a day-ahead market. A day-ahead market is one element that is present across RTOs. In contrast to a full RTO, the proposed day-ahead market designs allow Bonneville to retain substantial control over its transmission assets and preserve its BAA responsibilities. Moreover, as the Supreme Court explained, "[t]he intention of Congress can be

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[204] *See* Bonneville Project Act, 16 U.S.C. § 832a(b) ("[T]o encourage the widest possible use of all electric energy that can be generated and marketed . . . the administrator is authorized and directed to provide, construct, operate, maintain, and improve such electric transmission lines . . . as he finds necessary, desirable, or appropriate for the purpose of transmitting electric energy . . . to existing and potential markets . . . .").

[205] 42 U.S.C. § 16431.

[206] Order No. 888, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*; *Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, 75 FERC ¶ 61,080 (1996); *Open Access Same-Time Information System and Standards of Conduct*, Order No. 889, FERC Stats. & Regs. ¶ 31,035 (1996), *order on reh'g*, Order No. 889-A, FERC Stats. & Regs. ¶ 31,049 (1997), *order on reh'g*, Order No. 889-B, 81 FERC ¶ 61,253 (1997), *order on reh'g*, Order No. 889-C, 82 FERC ¶ 61,046 (1998); Order No. 2000, *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (Dec. 20, 1999).

[207] *Comprehensive National Energy Policy: Hearings Before the Subcomm. on Energy and Air Quality of the Comm. On Energy and Commerce*, 108th Cong. 57 (Mar. 5, 2003) (Serial No. 108-7).

gleaned, at least in part, by reference to prior law, as Congress is presumed to be knowledgeable about existing law . . . ."[208] Thus, while the development of a day-ahead market is not an RTO, it is reasonable to conclude that Congress contemplated federal utilities would be authorized to participate in subcomponents of an RTO, like a day-ahead market, as part and parcel of that express authority.

7. Bonneville participation in a day-ahead market must be effectuated through rates and tariff terms and conditions.

If Bonneville participates in Markets+, it will continue to establish its power and transmission rates in Northwest Power Act section 7(i) rate proceedings, and it will set the terms and conditions for transmission service in tariff proceedings.[209] Under Section 7(a)(1) of the Northwest Power Act, the Administrator establishes "rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established . . . to recover . . . the cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment . . . over a reasonable period of years and the other costs and expenses incurred by the Administrator . . . ."[210] Under section 7(a)(2), the Federal Energy Regulatory Commission reviews Bonneville's proposed rates to ensure they are 1) sufficient to assure repayment of the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs, 2) based upon the Administrator's total system costs, and 3) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.[211]

In a day-ahead market, Bonneville's rates must continue to be sufficient to recover total system costs including the Fish and Wildlife program, the Residential Exchange Program, amortization of existing debt, Columbia Generating Station financing, conservation, depreciation expenses, costs associated with achieving financial policy objectives, and costs associated with market participation. Bonneville's rates must also equitably allocate the cost of the transmission system between federal and non-federal uses. Bonneville's rates are based on forecasts and risk adjustment mechanisms respond holistically to actuals differing from forecast. Bonneville anticipates aggregate treatment of market benefits, which may vary based on products and services. In a section 7(i) rate proceeding, Bonneville would assess how to reflect the costs and benefits of market participation in rates, considering the interaction of any new mechanisms with existing policies. Participation in a day-ahead market would not change the Administrator's obligation to set rates to recover total system costs.

In addition to rate updates, the agency would need to make changes to the terms and conditions of transmission service it provides to customers to enable participation in a day-ahead market. Bonneville's governing statutes grant the Administrator broad discretion to set the terms and conditions of transmission service, which would include any terms and conditions necessary to join a day-ahead market. Several statutory provisions provide the basis for Bonneville's authority to determine the terms and conditions of transmission service.[212] In general, these statutory provisions grant Bonneville the discretion to act in a business-like manner when selling transmission at cost-based rates and to make decisions to effectuate that goal. While the details of such changes would depend on the market design, Bonneville would continue to sell and provide transmission service under its OATT as it does today. Bonneville will continue to monitor the development of market rules associated with transmission, including potential changes in transmission

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[208] *Native Village of Venetie I.R.A. Council v. State of Alaska*, 944 F.2d 548, 554 (9th Cir. 1992) (citing *Goodyear Atomic Corp. v. Miller*, 486 U.S. 174, 184–85 (1988)).
[209] 16 U.S.C. § 839e(i).
[210] 16 U.S.C. § 839e(a)(1).
[211] 16 U.S.C. § 839e(a)(2).
[212] 16 U.S.C. §§ 832a(b), 832a(f); 16 U.S.C. § 837e; 16 U.S.C. §§ 838b, 838d.

revenue due to market impacts and congestion rent design, to assess potential transmission customer impacts. Bonneville would conduct a terms and conditions proceeding to update its tariff with any changes necessary to enable day-ahead market participation. Section 9 of Bonneville's OATT describes the process for changing terms and conditions. Such a proceeding would be in accordance with Section 212(i)(2)(A) of the Federal Power Act.[213]

8. Bonneville will continue to meet its environmental obligations, including those under the Northwest Power Act, Endangered Species Act, and National Environmental Policy Act.

Another important set of Bonneville responsibilities involves the operation of the hydro system in coordination with the U.S. Army Corps of Engineers and the Bureau of Reclamation. The agencies manage the Federal Columbia River Power System for multiple project purposes including flood control, navigation, irrigation, fish and wildlife, power production, and recreation. Bonneville's participation in Markets+ cannot conflict with meeting non-power objectives, and Bonneville must continue to meet its environmental statutory obligations. As discussed herein, the designs include special considerations for hydro bid curves to recognize obligations and operational flexibilities of hydropower projects. The Markets+ designs do not appear to present a conflict with meeting these objectives, but as more details are developed it is essential that Bonneville maintain the flexibility and discretion necessary to meet non-power objectives. Bonneville will continue to ensure that Federal Columbia River Power System projects are managed for all project purposes and recognize system-wide operating constraints.

In a day-ahead market context, Bonneville would maintain operations to support ESA-listed fish species. Bonneville would also continue to meet Northwest Power Act requirements. Bonneville's power marketing services and activities, and its actual power operations to meet load obligations, would continue to be conducted consistent with applicable Biological Opinions and within existing operating constraints and normal operating limits of the projects. If Bonneville were to pursue participation in a day-ahead market, it would also assess the potential environmental effects that could result from implementing the decision consistent with the National Environmental Policy Act.

9. Conclusion

Bonneville's decision to join any market must comport with its legal obligations including to provide preference and priority in the sale of power, make firm power sales under section 5(b) of the Northwest Power Act, provide transmission service and operate the transmission system, set rates sufficient to repay the federal investment, and fulfill environment, fish and wildlife obligations. Bonneville has not identified any legal impediment to meeting these objectives if it joins Markets+.

[213] 16 U.S.C. § 824k(i)(2)(A).

Appendix B

West-Wide Governance Pathways Initiative Overview and Assessment

In July 2023, the West Wide Governance Pathways Initiative was launched with a mission to develop and form a new and independent entity with an independent governance structure capable of overseeing an expansive suite of West-wide wholesale electricity markets and related functions. This effort was led by a Launch Committee comprised of representatives from across a wide range of sectors. While its working meetings were closed, the Launch Committee held monthly public stakeholder workshops to provide updates on progress. Work products were released throughout the process and there was an opportunity for public comment. It is worth noting that the Western Area Power Administration, another Federal power marketing administration, participated on the Launch Committee. Bonneville participated in all public stakeholder meetings and provided comment at every opportunity. Bonneville was also an active participant in Pathways Step 2 work groups and contributed significant staff time to that effort.

The Pathways initiative resulted in two outcomes: Step 1 proposed a transition of the WEM Governing Body from a governance model of joint authority to one of primary authority with a provision for dual filing by the WEM Governing Body and CAISO Board of Governors at FERC in the case of an unresolvable dispute (discussed above). Step 2 proposes a significant transition to create a Regional Organization (RO) with an independent board that governs the WEIM and EDAM Tariff. Under the proposed approach, CAISO would continue to operate the market, would hold all financial and contractual liability, and maintain a shared tariff between CAISO and the RO. Some limited staff responsibilities may shift to the RO; however, the specifics of staffing remain open at the time of the final Step 2 proposal to be determined during the formation of the RO. The final proposal recommends that the new RO undertake a feasibility study within 9 months of formation to evaluate further advancements in market independence. The full Step 2 proposal can be found here.

Assessment of Pathways Step 1

Bonneville has evaluated the outcomes of the Pathways initiative as part of its day-ahead markets decision process. Bonneville believes that Step One, by itself, does not achieve the level of independence from any one state's authority that is necessary for a regional market. Bonneville does not view Primary Authority as more independent than Joint Authority. Bonneville is concerned that the transition to Primary Authority could lead to the CAISO Board of Governors being disconnected from WEIM and EDAM issues and could increase conflict between the Board of Governors and the WEIM Governing Body.

Under Step 1, the CAISO Board of Governors would retain sufficient authority to take back the steering wheel when certain conditions arise (to maintain fiduciary responsibility under California law) described as exigent circumstances. "Exigent circumstances" is a very broad concept, and by its nature, would likely be called upon during a crisis, e.g., a reliability event, a price spike, or a call by California-elected officials to take action. Such events will be sudden and chaotic. It would be concerning for parties outside of California to be exposed to a sudden assertion of control by the CAISO Board of Governors when the WEM Governing Body, by the nature of its primary focus on the market, may have superior understanding of the issues.

The Step 1 proposal does not achieve independent market governance to meet Bonneville's principle.

Assessment of Pathways Step 2

As described above, the Step 2 final proposal represents a significant shift from the current governance structure of the WEIM and EDAM. It moves governance of those markets to a Regional Organization with an independent board. Market operations would remain under the single CAISO Tariff that includes

CAISO's administration of its BA. The RO would hold sole authority for sections of the CAISO Tariff applying to market operations and joint authority with the CAISO BOG for tariff provisions of overlapping application to both markets and the CAISO BA. The RO acts as a policy organization, governing policy related to the markets. Operation of the market remains with CAISO, as does corporate and financial liability related to the market. The step 2 final proposal also describes significant changes to the stakeholder process to enhance the role of stakeholders and shift away from the staff-driven process that CAISO uses today.

In evaluating the Step 2 proposal, Bonneville assessed whether the proposed approach achieves independent governance for markets. Under the proposal, the RO board members would be nominated and chosen through an independent sector-based process; they would not be selected by the California governor and confirmed by the California Senate, which is an advancement from the current state. However, market operations and administration would remain under the direction of the CAISO Board of Governors and, therefore, would not achieve full independence from the State of California.

Bonneville does not believe the Pathways Step 2 achieves the independent governance contemplated in Pathways' charter. This appraisal is not a matter of subjective opinion about what degree of independence would be good enough; the proposal creates conflicts that undermine any claim of independent governance and operations. As discussed below, the Regional Organization proposed by Pathways does not achieve independent market operations, an independent tariff, independent contracts, and the ability to provide RTO services absent future legislation. The market contemplated by the proposal remains California's market, adding an independent policy board with limited authority for market operations and administration.

1. Independent Market Operations

First, the Regional Organization would not have independent oversight and administration of market operations. Instead, the market would continue to be operated by the market's largest BAA, CAISO. This sets up a conflict of interest. For governance to be independent, CAISO should have the same role as any other BA in the market.

The RO board may find itself in a frustrating situation. While it has authority in market design, it would have no executive authority to manage operations to ensure the market is faithfully implemented. Further, the RO will be forced to take market operations services from a single provider without regard to potential competitive market operation services. The proposal notes that, while a typical arms-length contract allows a dissatisfied party to choose to not continue doing business with the other, "[t]he RO would be more or less required to use the CAISO[.]" Operations would answer to a state entity, with no remedy available to the Regional Organization.

Without legislative change, CAISO and its employees would remain subject to California legal requirements to act for the benefit of California. *See* Cal. Pub. Util. Code § 345.5. The market would be operated by a single BA in the market footprint with duties to itself and its state. Pressure to favor California could manifest in subtle ways, such as how issues are framed and presented, and in prioritizing work under time and staffing constraints. Bonneville believes that California regulatory agencies and the state's legislature will retain disproportionate influence on policy development. The Pathways proposed role for the Regional Organization to weigh in on select hiring decisions is a small step forward but ultimately does not get to the heart of the issue.

Bonneville is also concerned that this conflict of interest and lack of operational authority for the RO will have impacts on participants in emergency or shortage situations. The Pathways proposal states it is standard practice for operators to be able to act in an emergency without seeking advance blessing from a board. Bonneville is not advocating for emergency operations to be brought to a board before responding to a crisis. Instead, it is imperative that operations are independent, so the operators have no incentive to favor one participating BA. Until CAISO's load service responsibility and Western energy market operator responsibilities are performed by completely separate entities, the market will not be independent.

2. Independent Tariff

Second, the proposal recommends an integrated tariff with continued joint authority over many tariff sections. The Regional Organization would not have sole authority over the tariff. The CAISO tariff would remain the relevant tariff. An integrated tariff creates conflicts over who has authority over which provisions, and who decides how certain initiatives are classified. An independent market would not intentionally choose to integrate its tariff with that of a single participating BA. From a practical standpoint, joint management of a tariff would be needlessly cumbersome and inefficient. From a legal standpoint, the ambiguity regarding authority could result in unjust and unreasonable implementation of the tariff.

Joint provisions are not necessary. General provisions could be copied and pasted to create two separate tariffs. Provisions specific to CAISO BAA could be unwound from sections that should be under the Regional Organization's sole authority. For the Regional Organization to have independent authority, it must be clear what authority it possesses. If the reluctance to separate tariffs is driven by cost considerations or the difficulty of precisely defining CAISO's new role, it is worth the investment now to address the issues to ensure unambiguous, just, and reasonable terms and conditions rather than in the heat of a future controversy. In order to achieve an independent governance structure, separate tariffs are a necessity.

3. Independent Contracts

Under the Step 2 proposal, CAISO would remain the counterparty to contracts with other market participants. This status is unique among participating BAs. It creates conflicts if CAISO interprets the contract differently than the Regional Organization. This could be a problem for CAISO if CAISO disagrees with the Regional Organization over what market rules are required or prohibited by the contracts. This is problematic for the Regional Organization if it adopts market rules applicable to scheduling coordinators and participating generators but lacks privity to enforce any related contract action. It is not clear that the Regional Organization would have any authority to amend contracts if it determines such amendments are necessary or desirable. Even if CAISO and the Regional Organization attempt to coordinate and align on interpretations, this continues to give one market participant undue influence over contracts with all other market participants. One participating BA should not be able to wield influence over the contracts of all market participants. As proposed, this contractual influence would not be shared or checked even by the Regional Organization itself.

These conflicts would not simply be philosophical differences of opinion. Under option 2.0, CAISO would retain financial responsibility, liability, and compliance obligations, which represents significant risk for CAISO. Therefore, when conflicts occur, the stakes will be high, and CAISO will naturally be incented to act in its own interest. The party that sets market rules should be impacted by the practical financial and legal ramifications of those rules. When the relationship between authority and impact is severed, as they are in the Step 2 proposal, conflict is inherent.

Despite the foregoing critique, Bonneville supports and appreciates the advancements made in the stakeholder process in the Step 2 final proposal. It has been Bonneville's experience that a more stakeholder-driven approach leads to increased collaboration, compromise, and ultimately better outcomes for market stakeholders. The Pathways Step 2 proposal introduces a stakeholder process with an increased role for stakeholders, including a more empowered stakeholder representative committee and indicative voting. The final proposal also includes an appropriate role and representation for federal power marketing administrations in both the stakeholder process and public interest process.

Appendix C

Potential Regional Transmission Organization Formation

Consistent with Bonneville's strategic plan, Bonneville is considering an incremental approach to market expansion. While Bonneville is only considering day-ahead market participation in this process, Markets+ may offer more potential for further integration into an RTO. SPP is a fully independent entity that does not require any legislative changes to meet FERC's requirements for RTO operation. In contrast, Bonneville has not observed a similar pathway for CAISO to support a full, multi-state RTO, including BAA consolidation. Even the most aggressive Pathways Initiative phase results in California as an ISO with the potential for a separate RTO operating outside of California in multiple states. SPP also has decades of experience operating a multi-state RTO, and its stakeholder-driven governance framework effectively navigates complex issues, while building trust among stakeholders. Accordingly, the Markets+ design is better positioned to provide additional market evolution and business opportunities for Bonneville as it confronts an increasingly dynamic electric utility business environment. If Western utilities begin to contemplate RTO formation in the future, Bonneville would conduct a transparent public process to evaluate the potential impacts of joining an RTO.

Appendix D

Seams Assessment

1. Transmission Operations, Seams, and Related Agreements

Seams are not a new concern for utilities, load serving entities, merchants, or marketers operating in the Western Interconnection. There is a mix of both bilateral trading and participation in organized markets, such as CAISO markets (day-ahead, hour-ahead, and WEIM) and WEIS. Bonneville has a service territory spanning seven states and is a significant provider and operator of high-voltage transmission service in the Pacific Northwest. Bonneville also operates a BAA in the Pacific Northwest that is adjacent to 18 BAAs (~360 individual ties) and 15 TSPs, including several TSPs that are embedded within Bonneville's BAA. Further, Bonneville is currently participating in the WEIM along with 14 of its adjacent BAAs.

While many diagrams and maps of the WECC and the Pacific Northwest often show tidy contiguous borders between BAAs and TSPs, the reality is much more complicated, especially in the Pacific Northwest, where many BAAs are often non-contiguous with loads and resources pseudo-tied across multiple TSPs and geographic zones, including generation-only BAAs. Bonneville also plays an integral role in the WECC as a key TSP, TOP, and TO of transmission assets that provide connectivity both within the Pacific Northwest and between the Pacific Northwest and the rest of the WECC footprint.[214] Given the numerous and complex commercial and operational seams that Bonneville and other WECC entities deal with daily and that have been refined over 75+ years, the region and Bonneville will need to work collaboratively to address the introduction of multiple new day-ahead market seams.

Seams exist today and produce operational and commercial friction and inefficiencies that must be carefully managed. Bonneville will likely have generation, load, and transmission participating in or impacted by both markets requiring various agreements, constraints, protocols, procedures, and market designs to ensure operational and commercial seams issues are addressed. With the introduction of multiple day-ahead markets with their own footprints, designs, protocols, and procedures, avoiding negative operational and commercial externalities will be critical.

The operational and commercial situation in WECC stands in stark contrast to the RTOs/ISOs that exist in the Eastern Interconnection.[215] In eastern RTOs,/ISOs, they are vertically aligned among roles[216] as well as having mostly contiguous footprints (relative to WECC). As such, the types of seams and the negotiation of seams among the various operational and commercial concerns involve far fewer parties and less complexity. The introduction of additional day-ahead market seams in WECC will involve many more entities than would be present under an RTO/ISO regime.

To combat these complexities, Bonneville will engage entities early and with ideas of how to decrease the relative complexity. Depending on the footprint, multiple MOs and RCs will need to be involved in these conversations. Bonneville has extensive experience in developing transmission and operating agreements with multiple BAAs and Bonneville will bring that experience and understanding to the conversation.

The discussion below identifies examples of the types of commercial and operational seams that the region and Bonneville will need to address to implement multiple day-ahead markets in the WECC.

1.1. Operational Seams

1.1.1. Balancing Authority Area

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[214] *E.g.*, Northwest AC Intertie (NWACI) and Pacific DC Intertie (PDCI).
[215] *E.g.*, SPP, Pennsylvania, New Jersey and Maryland Interconnection, Mid-Continent Independent System Operator.
[216] *I.e.*, RC, MO, BAA, TSP.

BAAs may experience increased operational complexity due to the need to manage interactions with multiple day-ahead markets simultaneously. Each market may have its own scheduling, dispatch, and settlement processes, requiring BAs to coordinate their activities to ensure integration of market transactions while maintaining reliability.

1.1.2. Reliability Coordination

Multiple non-contiguous RCs in the Pacific Northwest with complex seams will make it potentially more difficult to reliably manage operational issues when they arise given the additional coordination and lack of complete regional authority. Existing multiple RCs in the Pacific Northwest have much simpler seams today.

This may be further complicated by the difference in BAA and TOP areas (geographical or electrical). Bonneville is the TOP for facilities that are not in the Bonneville Transmission BAA (e.g. Heyburn/Unity are in Idaho Power's BAA and Drummond/Swan Valley are in PAC East's BAA). Under the NERC Rules of Procedure *(ROP Section 500, 1.4.1)*, all areas *(geographic or electrical)* are required to be "under the oversight of one and only one RC." There are currently no situations in the Pacific Northwest where a BA or TOP takes services from multiple RCs. If there are multiple markets within the Pacific Northwest with each taking primary RC services from the respective MO organization, this creates a possibility that some entities that perform these functions over areas that transcend the footprints of more than one market may be required to take services from more than one RC. This complexity may make it more difficult to reliably manage certain operational issues when they arise, as well as increase the communication and compliance burden.

RC-RC coordination will be critically important to minimize reliability risks. Bonneville has not made any determination regarding whether if Bonneville will switch RCs. However, having multiple non-contiguous RCs and MOs in the Pacific Northwest will pose many operational and commercial challenges due to:

- Potentially complex and non-contiguous boundaries;
- Competing priorities and objectives;
- Unique requirements, business practices, and complex coordination needs;
- Complex seams agreements.

These types of seams pose many challenges that, if not addressed and mitigated, will impact reliability. Through implementation, Bonneville will seek to lessen these impacts and risks.

1.1.3. Transmission Operations

The Pacific Northwest to California transmission corridor is one of the most important in WECC. A problem along this corridor can have serious implications for the entire Western Interconnection, and specifically, entities within the Pacific Northwest that depend on the Bonneville Transmission System. Further, many of the paths for which Bonneville is the TOP are shared amongst multiple asset or capacity owners and TSPs. These include, but are not limited to:

- **NWACI:** Many entities are involved in the NWACI. Bonneville is the operator and the BAA of the facilities north of the California Oregon Border. There are multiple asset owners (Bonneville, PAC, Portland General Electric [PGE]) and capacity owners, many who also provide service under an OATT as a TSP. The facilities that make up the NWACI support important transfers with CAISO, PAC, PGE, Idaho Power Company, BANC, and Nevada Energy, all of whom have either declared a leaning to join EDAM or signed an implementation agreement to join EDAM.
- **PDCI:** The PDCI is a controllable DC transmission path between the PNW (Bonneville

Transmission) and Southern California (LADWP), where LADWP has chosen to join EDAM. North of Nevada Oregon Border (NOB), Bonneville is the sole owner while south of NOB the ownership is split amongst multiple entities (LADWP, CAISO, Glendale, and Burbank). As operators of the DC converter stations at Celilo and Sylmar, Bonneville and LADWP control the PDCI dispatches and jointly manage the path.

- **South of Allston:** South of Allston is a shared path between Bonneville, PGE, and PAC, with the latter two having signed EDAM implementation agreements. Like other paths, Bonneville manages the path and determines the total transfer capability, which is subsequently allocated.
- **Other Shared Paths Include:** North of Echo Lake, West of Hatwai, North of Pearl, Montana-Northwest, and the Northern Intertie.

These types of shared paths impact multiple TSPs and BAAs and must be carefully managed and coordinated. Situations that increase the amount of coordination and seams issues on paths like these may increase the risk of adverse commercial and operational outcomes. Depending on the ultimate RC and market footprints, new agreements and procedures may need to be developed in order for everyday operations to continue to be reliable and efficient.

1.1.4. Mismatch Between Market Processes and Real-Time Operations

Each market may have differences in processes such as interchange scheduling rules, scheduling intervals, timing requirements, intertie bidding, rules for submitting bids and offers, and market clearing timelines. This misalignment can lead to difficulties in coordinating generation and transmission schedules between the two markets and aligning market schedules and dispatches with real-time operations. As part of implementation, Bonneville will need to consider all of these aspects as procedures and protocols are developed. The details will not be known until implementation.

1.1.5. Transmission Constraints and Market Congestion

Differences in how transmission constraints are modelled, market flows are calculated, and how subsequent flows are managed in each market can result in congestion at interfaces between or within the two market footprints. This "market congestion" or "commercial congestion" may affect the efficient utilization of transmission capacity and lead to suboptimal dispatches and pricing outcomes. Transmission opt-outs, SFCs, Transmission Corridor Constraints, ETSRs, and other nuances of each market's management of transmission constraints may cause the market(s) to be commercially constrained even though the transmission system is not physically overloaded.

1.1.6. Congestion Management

There is a potential of physical congestion occurring on transmission lines that serve as interfaces between the markets or transmission lines/flow gates/paths internal to one or the other market footprint. This congestion can occur regardless of being part of a market, but the management of congestion on transmission being used by two markets will likely require a more complex and nuanced approach. Managing congestion can also be more complex when market participants seek to arbitrage price differentials between markets, leading to potential congestion on specific transmission paths or flow gates. Seams agreements will likely be needed between the impacted entities[217] and the market operators to try and manage these types of operational risks.

1.1.7. Dynamic Transfer Capability (DTC)

Bonneville has numerous facilities with DTC limitations, such as the Northern Intertie, NWACI, PDCI,

[217] *E.g.*, BAAs/TSPs/TOPs.

Montana Intertie, and more generally across the Bonneville network. These limitations impact the ability of the system to reliably support large sub-hourly changes in flows and are addressed in Bonneville's Dynamic Transfer Business Practices. If there are multiple real-time markets within the Pacific Northwest, DTC will need to be allocated among multiple markets and managed via market constraints.

Further, the lack of DTC between two non-contiguous market zones (e.g., PNW and DSW) will limit sub-hourly optimization between the zones. Each zone, and the BAAs it contains, will need to manage intra-hour imbalances without the market's ability to economically transfer incremental energy dynamically between the zones. As a result, and to maintain reliability, the need for flexible resource capacity may increase, requiring either additional market procurements and/or additional reserves to be held by BAAs within each zone.

1.1.8. Interconnection Reliability Operating Limits (IROL)

Bonneville is currently subject to two IROLs, the Oregon Net Export IROL[218] and the NW WA Import IROL. Today, RC West is largely responsible for both IROLs. Having multiple non-contiguous RCs involved in managing IROLs, especially the Oregon Net Export IROL, will require the RCs to be tightly coordinated. Bonneville will continue to support large margins when studying and observing IROL limitations and also support the identification of a lead RC for each IROL.

1.1.9. Network Model Management / Coordination

Accurate models are critical to maintaining reliability. If there are multiple RCs, they will need to ensure they always have the same network models and that they communicate consistently to all BAs and TOPs. Bonneville will continue to advocate that RCs ensure network model alignment.

1.1.10. Operational Studies (assumption, datasets, outages, etc.)

Operational studies require not only an accurate network model, but also robust and accurate datasets and the ability to apply realistic assumptions. With multiple RC and market footprints in the Pacific Northwest, this may be a challenge and present risks across various time horizons.[219] Bonneville will continue to receive the assumptions from WECC as part of its offline studies, while the real-time contingency analysis tool will be using remote terminal units to receive real-time data and then perform state estimation.

1.1.11. Outage Coordination

Coordinating and managing outages across multiple MOs and RCs is critically important. In addition to using different Outage Management Systems, RCs and MOs may have differing requirements for outage submittals and timings and a single outage may require careful coordination with all entities depending on the nature of the outage. As part of any implementation, this will need to be further explored and coordinated.

1.2. Commercial Seams

1.2.1. Market Timing and Process Requirements (bi-lateral, day-ahead, real-time)

Differences in timing and process requirements between the various markets (day-ahead, real-time) may impact the ability to efficiently trade between market footprints. Business practices will need to be developed to address efficiency and accurate operation.

1.2.2. Resource Adequacy Programs (i.e., WRAP and CPUC)

Multiple RA programs may be difficult to reconcile across market footprints. There will need to be market-

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[218] The Oregon Net Export IROL addresses the interactions between the NWACI and Path 75/Path 14.

[219] Week-ahead, day-ahead, hour-ahead, real-time contingency analysis, etc.

to-market coordination to ensure generation capacity, and any energy deliveries are accounted for.

1.2.3. Jointly Owned Transmission (network and interties)

Managing existing jointly owned (asset or capacity) transmission agreements, along with any commercial arrangement and operational protocols, may be more difficult than they already are if the owners are spread across multiple non-contiguous RCs and markets. This is especially acute when one TSP and owner is located within a BAA that is participating in a different market. It will take time and engagement from all entities in the Pacific Northwest to ensure reliable operation and market efficiency.

1.2.4. Remote Load (i.e., load service in another BAA via transfer service)

Many utilities, including Bonneville, have generation and load in other BAAs. If the entity with remote load, such as Bonneville, has a different RC or the two BAAs are in different day-ahead and real-time markets, Bonneville acknowledges that it may be more difficult to service that load as it would likely require merchants to participate in both markets as well as deal with market-to-market energy transfers and it will need to be further explored upon implementation.

1.2.5. ATC ID, OATT, Business Practice Discrepancies between Adjacent TSPs or Joint Owners

While ATC ID, OATT, and business practice discrepancies exist today, depending on the design of the markets (timings, transmission donation processes, TSR queue pausing, etc.) and how transmission availability is calculated and reserved, adjacent TSPs may end up with impactful differences. These differences may cause bilateral trading and market-to-market friction. Affected parties will need to coordinate to minimize potential impacts.

1.2.6. Price Formation (between markets)

A critical concern of all organized markets is price formation methodology. Differences in these methodologies, both temporal and procedural, may result in structural price differences between markets that create incentives that work against both markets objectives or produce unintentional hurdles that limit efficient bilateral trades or efficient transactions between markets.

1.2.7. Commercial Transmission Rights (Congestion Revenue Rights, ATC, etc.)

Markets need access to transmission to effectively operate. Markets may leverage donated rights, unused ATC within the market footprints, physical capability of the system, or any combination of the above. Timing and access to transmission for day-ahead market participants and customers not participating in a day-ahead market may be complex to coordinate. Parties will need to establish methods to determine priority, transmission rights, and dispute resolution to avoid over or under-utilization of the transmission system. Proper incentives will more effectively manage congestion. Bonneville believes these complexities can be addressed through the standard tariff, rates, and business practice processes.

1.3. Other Seams Considerations

There are many other potential impacts to multi-RC/multi-MO environment that will need to be carefully weighed, such as:

- State Carbon Policies and GHG accounting
- Remedial Action Schemes
- Rate Pancaking (market to market)
- Data Sharing
- Market Flow Calculation and Management

- Reserve Sharing (market to market)
- Interchange Scheduling (timing requirements, etc.)
- System Integration and communication between markets
- Oversupply Protocols
- Transmission Loss Accounting
- NT redispatch (FCRPS and Non-Federal redispatch)
- Standardization of scheduling timelines between markets
- Water Management (Bi-Op)
- International Treaties
- Jurisdictional Status
- Blackout Restoration

1.4. Seams Agreements

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. Bonneville expects agreements, constraints, and market design to mitigate operational and commercial seams issues. Given the complexity of WECC, the potential for non-contiguous market and RC footprints, and the number of parties involved, multiple types of agreement will be necessary.

2. Seams Conclusion

Bonneville recognizes the operational and commercial challenges posed by multiple markets and RCs, the impacts of their potential footprints, and the resulting seams. Bonneville also recognizes and is aware of the complexities posed by seams, both operational and commercial. So long as more than one RC, MO, BAA, and TSP exist in WECC, seams will exist. However, some create more operational and commercial challenges and complexity than others. Bonneville and others will need to work collaboratively to manage these seams while continuing to prioritize reliability.

Appendix E

Congestion Impacts

In a day-ahead market, congestion occurs when available least-cost energy cannot be delivered to some loads because transmission facilities do not have sufficient capacity to deliver the energy, or there is insufficient transmission rights made available. Market optimization will create a plan to dispatch least-cost resources until the optimization reaches an identified limit, at which point it will begin to add to the dispatch plan the next least-cost resource that does not further impact the "binding" limit. An indication that congestion is occurring is "price separation" between two locations; the next least-cost resource that does not further impact the limit that can serve load on one side of the constraint may have a different price than the next least-cost resource on the other side of the constraint. To see an example of congestion, please see materials from public workshop 7 on June 3, 2024.[220]

The market optimization engine delivers day-ahead awards with resource schedules different from those that may have been established bilaterally. Unlike bilaterally established resource schedules, the planned dispatch pattern that results from participating in a day-ahead market is security-constrained (i.e., factors generation and transmission constraints when creating the optimized dispatch). Bonneville Transmission Services would be using scheduling limits established from internal studies to determine the capability of each path. The planned dispatch pattern could fully use the capacity over a path based on the data it had been supplied. However, congestion may still occur.

On the next operating day, in real-time, operational constraints may deviate from what was expected in the day-ahead optimized dispatch. In real-time, resources are redispatched to reflect updated constraints as other inputs such as load changes, variable energy resource output changes, and generation or transmission outages and derates are adjusted relative to the day-ahead solution.

As stated in Section 6.4, Bonneville has had positive experiences leveraging the WEIM to manage operational constraints and expects even greater congestion management effectiveness with the addition of a security constrained day-ahead market optimization

Bonneville is likely to have generation, load, and transmission participating in or impacted by both markets. It is possible that in a multi-day-ahead market scenario, the Pacific Northwest region will continue to see commercial congestion, rather than a reduction. Physical congestion represents the actual flow on a transmission element reaching the established reasonable maximum amount. Commercial congestion represents a limit to potential physical flow despite the physical limit not being reached. Because Bonneville will likely have transmission customers in both day-ahead markets, as well as in no market, Bonneville will have to determine how to allocate transmission capacity to each market. If each market is allocated a certain number of MWs on a flow-based path that are reflective of the transmission rights of that market's participants, each market may congest due to the commercial limits even though the physical limitation is not close to being reached. This could produce a less efficient solution for each market, especially in the day-ahead market, compared to if there was only one market or compared to how things are today in a bilateral market. This could also happen in the real-time horizon.

Another inefficiency that could be introduced is internal flow-based paths with expected counterflow and transmission rights that were originally sold based on non-coincidental use. Each market will have a unique portion of capacity for the same path, defined within their respective market. There could be the situation that the sum of all of the rights in a single direction add up to more than the capability of the path, in which

[220] *See* Bonneville's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation - Workshop 7 presentation (June 3, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-7-presentation-060324.pdf.

case scheduling limits would be needed for each market to fit the path limit. This would exacerbate the commercial congestion identified previously, because the non-coincident users may not be distributed between the markets in the same pattern as the coincident users. This might only be in the day-ahead market and then in the real-time market, scheduling limits could be relaxed based on the scheduled use.

As discussed in Appendix D, Bonneville plans to encourage the two market operators to begin developing a seams agreement that maximizes the efficient use of the transmission system while maintaining the reliable operations of the grid. With these future complexities in mind, Bonneville is proactively taking part in the Enhanced Curtailment Calculator Working Group (ECCWG) to advise on solutions for uniform congestion management process.

In summary, Bonneville believes there are likely congestion management benefits to transmission operations with Bonneville participating in a day-ahead market. In July 2023 and October 2024, Bonneville announced that it had identified multiple new transmission substation and line projects necessary to reinforce the Pacific Northwest's electric grid.[221] The completion of these projects will add capacity to Bonneville's transmission system, and the day-ahead market can deliver even more efficient dispatch solutions.

[221] *See* Press Release, Bonneville Power Administration, BPA takes major step to advance transmission projects for reliability and expansion (July 12, 2023), *available at* https://www.bpa.gov/-/media/Aep/about/publications/news-releases/20230712-PR-08-23-bpa-accelerates-work-on-transmission-projects-final.pdf; Press Release, Bonneville Power Administration, BPA maintains transmission expansion momentum with 13 new proposed projects (Oct. 15, 2024), *available at* https://www.bpa.gov/-/media/Aep/about/publications/news-releases/20241015-PR-18-24-bpa-maintains-transmission-expansion-momentum-with-13-new-proposed-projects.pdf.

Appendix F

Implementation Feasibility Assessment

In order to evaluate the implementation feasibility for Bonneville's Markets+ participation, a capability gap analysis was conducted, and 12 projects were determined to close the identified capability gaps in the following areas:

- Bidding and self-scheduling
- Data integration
- Settlements
- Price and dispatch
- Load and renewable forecast
- Metering
- Outage management
- Transmission scheduling and operations technology
- AGC modification
- RC Switch (if applicable)
- End-to-end billing process
- Post go-live technical support

Bonneville is in the process of developing an implementation plan to execute these projects, including changes in software, hardware, data integration, business processes, policies, and staffing. The implementation plan also includes market entry preparation, such as staff training, systems testing, market simulation, parallel operations, and production cutover. Initial estimates for funding and resources necessary to support this effort were included in Table 8 in section 5.1.2.3.

The main challenge of this implementation effort is the transition between two organized energy markets (i.e., WEIM to Markets+), which could require more resources to maintain two sets of systems and processes during the transition period. In many cases, discreet hardware, software, and network connectivity will be required to operate in parallel. Bonneville will strive to minimize the staffing impact by setting an appropriate timeline for implementation activities to space out the workload over time.

Bonneville will focus on deliberate timing, adequate funding, and appropriate staffing in the implementation process while leveraging prior experience implementing the WEIM. In addition, Bonneville plans to get support from a consulting services firm specializing in the energy utilities industry with expertise in market-to-market transition as a critical component to a successful and effective market entrance.

EXHIBIT B

Bonneville's Day-Ahead Market Policy Record of Decision

May 9, 2025

Bonneville Power Administration

Day-Ahead Market Policy

Record of Decision

May 9, 2025

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1. Executive Summary

The Bonneville Power Administration's (Bonneville) Day-Ahead Market Policy (Policy) sets forth the policy direction of Bonneville to pursue participation in the Southwest Power Pool's (SPP) Markets+. The Day-Ahead Market Policy Record of Decision (ROD) responds to public comments submitted in response to Bonneville's Draft Day-Ahead Market Policy (Draft Policy) published March 6, 2025.

Alongside the Policy, this ROD documents the basis for Bonneville's decision to adopt a direction towards participation in SPP's Markets+ day-ahead market. The Day-Ahead Market Policy and ROD describe the agency's public process, evaluation principles, economic analysis, market design analysis, and governance assessment that provide the basis for the Policy. The purpose of the Policy is to transparently provide stakeholders with information about the scope of subsequent actions towards market participation. The policy clarifies the policy direction for scoping future processes such as rate cases, tariff terms and conditions proceedings, transmission business practice updates, and other steps towards participation, such as a Provider of Choice long-term firm power sales agreement amendment process if Bonneville joins the day-ahead market as a participant.

The issues raised by commenters and responded to by Bonneville generally follow the order of topics presented in the Policy. The ROD indicates where public comments resulted in updates or changes to the Policy.

2. Introduction

Bonneville has completed an extensive multi-year public process to determine the direction and next steps regarding its participation in a day-ahead market. In the Policy, Bonneville establishes the agency's intent to pursue participation in Markets+. Bonneville received over 150 unique public comments and over 1,000 form letter comments from individuals on the Draft Policy. Bonneville appreciates these comments and addresses its review, evaluation, and responses to comments herein.

Bonneville's Day-Ahead Market Policy is timely, necessary, and critical to preserve and enhance the benefits of the Federal Columbia River Power System (FCRPS) and Federal Columbia River Transmission System (FCRTS). It establishes the scope for future implementation decisions related to Markets+, including cost allocation, rates, open access transmission tariff (OATT) terms and conditions, and ultimately a decision whether to become a market participant. Because it will take several years to implement day-ahead market participation for Bonneville, Bonneville has established its business rationale and intent now to set clear expectations for the scope of subsequent rate and tariff proceedings and mitigate uncertainty for customers, sovereigns, and stakeholders.

Bonneville received many comments in support of the policy direction from its customers. Bonneville also received comments from some customers and stakeholders criticizing its day-ahead market evaluation and suggesting that the agency should instead participate in the California Independent System Operator's (CAISO) Extended Day-Ahead Market (EDAM). Some of these commenters raised various concerns about Bonneville's economic analysis or the viability of Markets+ itself. While some commenters questioned the timeliness of the Policy and requested delay, others urged Bonneville to proceed with a decision to inform the choices of other balancing authority areas (BAA) considering participation in a day-ahead market.

Bonneville has a reasonable basis to proceed toward joining Markets+. Bonneville notes that it has held one of the most open and transparent public processes to evaluate day-ahead market participation. In comparison, electric utilities that have indicated they will or have taken steps to join EDAM did so largely without public process or transparency.[1] They are now rapidly implementing EDAM despite serious concerns about potential unjust and unreasonable transmission OATT terms and conditions in their BAAs.[2] Based on the evidence in the record, Bonneville does not agree with comments that conclude EDAM is the only viable or best market option available to Bonneville and the region. Bonneville's timing, processes, and expectations for Markets+ are supported by the record, and Bonneville finds no compelling legal or factual basis to change its policy direction.

In the past few years, CAISO and SPP both developed proposed day-ahead market frameworks to operate in the Western Interconnection. Each market's tariff has now been approved by the Federal Energy Regulatory Commission (FERC).[3] CAISO developed EDAM, and SPP developed Markets+. For each of these centrally organized wholesale electricity markets, the market operator will act as a clearinghouse for bids and offers from market participants. Market participants may continue to transact bilaterally until the close of the associated real-time market. Market results will determine how generation is dispatched to serve load in the least-cost manner both in day-ahead and real-time.

Bonneville is considering participation in a day-ahead market following its experience as a late entrant to the real-time (within-hour) Western Energy Imbalance Market (WEIM).[4] Based on this experience the agency's assessment is that day-ahead market participation at an early stage will better meet its customer and stakeholder objectives because the first years of market development greatly influence the development and maturation of the market design. Bonneville has determined that day-ahead market participation would allow for lowest-cost resource

[1] *See PacifiCorp*, FERC Docket No. ER25-951, Protest of the Bonneville Power Administration (Feb. 18, 2025); *Portland Gen. Elec. Co.,* FERC Docket No. ER25-1868, Protest of the Bonneville Power Administration (May 1, 2025).
[2] *Id.*
[3] *CAISO*, 185 FERC ¶ 61,210 (Dec. 20, 2023); *SPP*, 190 FERC ¶ 61,030 (Jan. 16, 2025).
[4] Bonneville Power Admin., Energy Imbalance Market, https://www.bpa.gov/learn-and-participate/projects/energy-imbalance-market.

dispatch, provide continued access to trading partners in the day-ahead timeframe, and allow for optimization of a broader resource mix to serve load which would better ensure system reliability.

3. Public Process

ISSUE 1: Whether Bonneville conducted an adequate stakeholder process

Draft Policy Position

Bonneville outlined its public process for the day-ahead market policy decision in Section 3 of the Draft Policy.

Public Comments

Bonneville received many supportive comments regarding its process, regardless of whether commenters agree or disagree with its policy direction.[5]

The Alliance of Western Energy Consumers (AWEC) comments that it participated in the stakeholder process "since its inception and deeply appreciates BPA's hard work and commitment to identifying a day-ahead market solution that best serves the interests of both its customers and the Region while, importantly, allowing the Agency to meet its statutory and contractual obligations to preference customers."[6]

The Public Power Council (PPC) comments, "we find it important to note that BPA's process has been robust and transparent." They stated that "[s]takeholders have been provided with regular opportunities to comment, discuss and debate a wide range of issues." They observed that "Northwest public power has a long history of not holding back when there has been concern with a federal process from a transparency or timing standpoint, and BPA's markets assessment process has been both well-designed and well-executed."[7] PPC further comments that "[a]s part of its well-run process, Bonneville also explained its evaluation criteria and analysis very clearly every step of the way."[8]

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[5] *See, e.g.*, Big Bend-040725 at 1; CBEC-033125 at 1; Cowlitz-040725 at 1; CPC-040725 at 1; CRPUD-040725 at 1; EWEB-040725 at 1; Franklin-040225 at 1; Hood River-040425 at 1; IFP-040725 at 1; Joint Authors-040725 at 1-2; Modern-040425 at 1; OR-WA State Agencies-040725 at 1; NIPPC-040725 at 1; NRU-040725 at 1; Pacific-040725 at 1; Snohomish-040725 at 7; Tacoma-040725 at 1; Wasco-033125 at 1; WPUDA-031225 at 1, 4.
[6] AWEC-040725 at 1.
[7] PPC-040725 at 2.
[8] *Id.*

The Northwest and Intermountain Power Producers Coalition (NIPPC) states that it "appreciates the efforts BPA has undertaken to explain to customers how day-ahead markets work and to articulate the benefits of BPA joining a day-ahead market. NIPPC especially appreciates the efforts BPA has taken to explain how BPA's participation in a day-ahead market will impact customers, including explaining the options and potential financial implications customers will face in scheduling or donating their transmission rights for market optimization, as well as the extent of their exposure to market prices under the various market options."[9]

Renewable Northwest (RNW) states that it "appreciates the thorough process and review that has led to the publication of the DAM Draft Policy."[10]

The Western Public Agencies Group (WPAG) states, "[w]e appreciate the methodical approach that BPA has taken thus far in its deliberations and look forward to BPA's continued application of the principles of transparency, collaboration, and equity as we move into additional phases of BPA's day-ahead market process. Finally, thank you to BPA's staff for their helpful engagement and hard work on this important issue over the last several years."[11]

Several entities raised questions or concerns with Bonneville's stakeholder process. The Northwest Energy Coalition (NWEC), Idaho Conservation League, and Earthjustice (Earthjustice) state, "[w]hile we recognize the time and effort BPA has put into evaluating day-ahead market options, its response to public input has been minimal and its decision-making process has been opaque and appears more focused on catering to a narrow set of interests rather than the broader public good."[12]

Seattle City Light (SCL) requests that Bonneville "provide an explanation of how the principles are interpreted, and what elements/criteria define how a DAM is measured against those principles."[13]

The Confederated Tribes of the Umatilla Indian Reservation (CTUIR) expresses concern that Bonneville did not provide enough time for comments on the Draft Policy and that Bonneville executed the SPP Phase 2 Funding Agreement prior to completing its public workshops,[14] tribal consultations, and publication of the Policy and ROD.[15] The Confederated Tribes and Bands of the Yakama Nation (Yakama Nation) echo CTUIR's concerns and further state that Bonneville has not fully disclosed economic impacts that may result from the day-ahead markets policy

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[9] NIPPC-040725 at 1.
[10] RNW-040725 at 1.
[11] WPAG-040725 at 6.
[12] Earthjustice-040725 at 1.
[13] SCL-040725 at 54, 77.
[14] *See* Issue #8 for further discussion of the Markets+ Phase 2 Funding Agreement.
[15] CTUIR-040725 at 1-2.

direction.[16] CTUIR express concern that Bonneville did not provide enough time for comments on the Draft Policy and that Bonneville executed the SPP Phase 2 Funding Agreement prior to completing its public workshops,[17] tribal consultations, and publication of the Policy and ROD.[18] Yakama Nation echo CTUIR's concerns and further state that Bonneville has not fully disclosed economic impacts that may result from the day-ahead markets policy direction.[19]

Regarding further process, WPAG and PPC request that Bonneville develop and publish a customer engagement plan as part of its ROD. WPAG states, "WPAG recommends that BPA . . . detail the next phases of its day-ahead market decision making and implementation processes, including stakeholder engagement plans." They suggest that "[t]he first phase of such engagement should commence immediately after BPA publishes the DAM ROD . . . [t]here remains a lot to do, and BPA and its customers have likely only scratched the surface."[20]

Evaluation

Some commenters requested that Bonneville conduct additional process before determining its direction regarding day-ahead market participation. Bonneville responds to requests for further delay in Issue #13, herein. Bonneville also directly responds to requests for tribal consultation and government-to-government consultation in Issues #49 and #50 herein.

As described in Section 3 of the Policy, Bonneville held 11 public workshops, regularly engaged with customers, supported market design development of Markets+ and EDAM, and provided regular comment periods for stakeholders, including a 30-day formal comment period after publication of its Draft Policy on March 6, 2025.[21] This process has been consistent with Bonneville's agency-wide approach of conducting open and transparent public processes.

As discussed in Section 4 of the Policy, Bonneville developed principles for evaluation of the day-ahead market policy decision with public input. As set forth in the Policy, Bonneville's direction comports with these evaluation principles. Bonneville further discusses requests to weigh the principles in Issue #11 herein. Bonneville also received requests to consider other evaluation criteria, such as from PPC related to PPC's three lenses (firmness of power supply,

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[16] Yakama-040725 at 1-2.
[17] *See* Issue 8 for further discussion of the Markets+ Phase 2 Funding Agreement.
[18] CTUIR-040725 at 1-2.
[19] Yakama-040725 at 1-2.
[20] WPAG-040725 at 4; PPC-040725 at 7.
[21] *See* Bonneville Power Admin., *Day-Ahead Market*, https://www.bpa.gov/learn-and-participate/projects/day-ahead-market (day-ahead market policy and workshop materials); Bonneville Power Admin., Bonneville's Public Engagement for Establishing a Policy Direction on Potential Day Ahead Market (DAM) Participation – Workshop 5 presentation (Feb. 1, 2025), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/dam-workshop-5-presentation-20240201.pdf.

certainty of delivery, and environmental attributes), and BPA has been mindful of such requests in its evaluation.[22]

Decision

Bonneville's public process has been open and transparent. While not all commenters agree with the agency's conclusions, the Policy and ROD provide extensive analysis supporting Bonneville's day-ahead policy direction.

4. Public Process

Bonneville addresses its evaluation principles in Issue #1 and Issue #11 herein.

5. Day-Ahead Market Participation Evaluation

5.1. Economic Costs/Benefits Analyses

As part of its day-ahead market evaluation, Bonneville assessed costs and benefits using PCM. PCM is an industry-standard approach for analyzing costs and revenues associated with energy trading and load service.

5.1.1. Production Cost Modeling

ISSUE 2: Whether Bonneville adequately considered production cost modeling (PCM) and the limitations of PCM when determining its policy direction

Draft Policy Position

Section 5.1.1.1 of the Draft Policy described how PCM analysis is a simplified process to model a market optimization resulting in hourly generation dispatches and associated production costs. PCM incorporates a Security Constrained Unit Commitment (SCUC) and a Security Constrained Economic Dispatch (SCED), which are the processes the day-ahead market uses to optimize participants' loads, resources, and transmission. "Security Constrained" refers to transmission and generation limits and other operating constraints. "Unit commitment" determines the optimal combination of resources to bring online from those that are available for some or all of the operating day. "Economic Dispatch" refers to generation resource market awards (in other words, megawatt outputs for each resource) based upon the least-cost resources considering such constraints. The PCM analysis produces hourly generation dispatches and associated electricity production costs to serve load based on operational inputs such as generation resources, loads, transmission connectivity, and transmission constraints.

[22] PPC-040725 at 4; Policy § 3.

As described in Sections 5.1.1.2 and 5.1.1.3 of the Draft Policy, Bonneville participated in two cost-benefit analyses using PCM as part of its day-ahead market evaluation. Bonneville joined the Western Markets Exploratory Group (WMEG) in the summer of 2022. WMEG participants, who operate 25 BAAs within the Western Interconnection, pooled resources to examine the potential economic benefits of participation in a day-ahead market. WMEG participants hired the Energy and Environmental Economics (E3) consulting firm to provide PCM analysis for BAAs across varying market footprints (BAA territory boundaries) and for varying years (2026, 2030, 2035). In one of Bonneville's initial day-ahead market initiative workshops on October 23, 2023, Bonneville and E3 provided an overview of the WMEG cost/benefit study and initial takeaways from WMEG results.

As described in Section 5.1.1.4 of the Draft Policy, Bonneville contracted directly with E3 in 2024 for supplemental analysis following the WMEG analysis. E3 further analyzed the WMEG data set by modeling additional market footprints and variables including hydro conditions and stressed conditions. One variable E3 tested included scenarios with various "hurdle rates" or "market-to-market" friction cost estimates applied to the footprint that best reflected utility indications regarding market participation, including Bonneville's staff recommendation towards participation in Markets+. In November 2024 and January 2025, Bonneville reviewed the supplemental E3 analyses in public workshops.[23]

In section 5.1.1.3.2, Bonneville concluded that the market footprint (defined mainly by participating BAAs) is a primary driver of results, and it is not certain what footprint will ultimately materialize. Bonneville determined it was prudent to focus on PCM results reflecting two day-ahead market footprints because both EDAM and Markets+ have support from various entities. Bonneville observed that PCM results with different hurdle rates drive differences in footprint benefits and found that lowered hurdle rates led the benefits in the most likely Markets+ footprint scenario to converge with the most likely EDAM scenario results.

Based upon consideration of the range of PCM results, Bonneville determined that the agency can achieve benefits above business-as-usual (BAU) with the expected Markets+ footprint, which is discussed in more detail below. Beyond the PCM results, the Draft Policy also discussed the limitations to PCM analysis, which is discussed below and further in Issue #3 on hurdle rates. Bonneville discusses other considerations including RA in Issue #21, fast-start

[23] *See* Bonneville Power Admin., BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation - Workshop 9 presentation (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/dam-workshop-9-presentation-110424.pdf; Energy and Environmental Economics, BPA WMEG Follow-Up Analysis (Nov. 4, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/E3Presentation-bpa-stakeholder-meetingnov4-2024.pdf ("WMEG Follow-up Analysis"); Bonneville Power Admin., BPA's Public Engagement for Establishing a Policy Direction on Potential Day-Ahead Market (DAM) Participation - Workshop 10 presentation (Jan. 29, 2025), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/dam-workshop-10-presentation-20250129.pdf.

pricing in Issue #23, scarcity pricing in Issue #23, price formation in Issue #23, market power mitigation (MPM) in Issue #24, and greenhouse gas (GHG) accounting in Issue #31.

Public Comments

A. Overall Positions

Bonneville received extensive comments about the Draft Policy assessment of PCM analysis. In general, commenters either support the direction towards participation in Markets+ based on considerations of PCM analysis and its limitations, or they disagree with Bonneville's conclusions. Some commenters suggested that, based on their own assessments, the agency should adopt a direction towards participation in EDAM instead of Markets+.

1) Comments in Support of the Day-Ahead Market Draft Policy Direction

Bonneville's public power customers generally support Bonneville's assessment of PCM analysis and its weighting of PCM analysis, market design, and governance. PPC represents Pacific Northwest non-profit, public power utilities to whom the Administrator must provide preference when making power sales. PPC's members fully subscribe the entire firm output of the FCRPS and a significant portion of the capability of Bonneville's transmission system.[24] PPC "concurs with BPA's assessment that Markets+ is the superior option to meet the criteria adopted as part of its decision process."[25] PPC's perspective is that while PCM analysis does not assess impacts to preference customers, they acknowledge that it indicates broad directional benefits from day-ahead market participation.[26]

PPC agrees with Bonneville that PCM studies provide meaningful information but are only one component of a wide range of analyses needed to inform a day-ahead market participation decision.[27] PPC agrees with Bonneville that PCM must be evaluated in the context of other important considerations and asserts that the models can be "highly reliant on speculative assumptions" and do not account for other important considerations.[28] PPC cautions that "[n]arrowly focusing on production cost study results will omit critical market design, reliability, statutory, and governance considerations that will have significant impacts to BPA and preference customers over the coming decades."[29] As discussed further in the analytic

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[24] PPC-040725 at 1 n.1.
[25] *Id.* at 3.
[26] *Id.* at 8.
[27] *Id.*
[28] *Id.* at 5
[29] *Id.*

components section below, PPC believes that inaccurate PCM assumptions contribute to results that "drastically overstates the difference in economic benefits between Market+ and EDAM."[30]

Northwest Requirements Utilities (NRU) represents the interests of 56 preference customers and one generation and transmission cooperative, all of whom hold Load Following and Network Integration Transmission contracts with Bonneville. NRU's members serve retail customers in eight states and contract with Bonneville for roughly 37% of its Tier 1 load.[31] NRU emphasizes that analysis of the forecast financial impacts are based on the use of PCM, the proposed market footprints and participating or non-participating entities therein, and the inclusion or exclusion of high-impact low-probability considerations such as tail events.[32] NRU does not opine on the relative weight or outcome of such variables, and agrees with Bonneville's assessment that a number of market design issues, including congestion revenue allocation, GHG accounting, and fast-start pricing cannot be quantified in detail.[33] NRU supports the comments submitted by PPC regarding the economic analysis in the Draft Policy.[34] Overall, NRU supports Bonneville's conclusions in the draft policy and agrees that Markets+ is the preferred direction at this time.[35]

WPAG is comprised of 27 preference customers located in Oregon and Washington, both east and west of the Cascades, from some of Bonneville's smallest load following customers to its largest and most sophisticated Slice/Block customers.[36] WPAG states that through "meticulous analysis," Bonneville demonstrates that participation in Markets+ would "provide better long-term value to BPA's customers based on its overall market design features including an independent governance model, uniform resource adequacy requirements, a congestion revenue design that incentivizes transmission investment, and superior greenhouse gas ('GHG') design."[37]

WPAG acknowledges that not all of the analysis in the draft policy clearly supported Markets+.[38] They recognized that PCM analysis indicated that participation in EDAM produced the highest benefit to Bonneville in the cases studied, followed by participation in the WEIM only, with participation in Markets+ producing the lowest projected benefit to Bonneville. WPAG "agrees with BPA that the PCM results are one factor that BPA must consider in making its day-ahead market decision, but should not be the only factor in its selection between Markets+ and EDAM

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[30] *Id.* at 11.
[31] NRU-040725 at 1.
[32] *Id.* at 3.
[33] *Id.*
[34] *Id.*
[35] *Id.* at 5.
[36] WPAG-040725 at 1.
[37] *Id.* at 2.
[38] *Id.* at 3 n.3.

to the exclusion of all other relevant factors favoring Markets+."[39] WPAG also expresses that the PCM results shared by Bonneville in workshops suggest that Bonneville can achieve additional net benefits if the two markets can work together to reduce hurdle rates below those assumed in the PCM base case.[40]

Similarly, as an overall matter, the Washington Public Utility Districts Association (WPUDA)'s 27 members and Energy Northwest also assert that "the benefits and costs that actually flow to BPA customers are likely to be affected by factors the Production Cost Modeling did not fully evaluate."[41] WPUDA describes how PCM does not factor in known industry trends like changes in Bonneville's load-resource balance resulting in a likely decline in surplus sales, downward pressure on wholesale prices from significant solar generation and battery storage developments, a lack of accounting for existing transmission rights, failure to assess the impacts of congestion rents, and lack of consideration of different EDAM and Markets+ design approaches such as MPM.[42]

AWEC represents large energy consumers in the region and has considered the importance of economic benefits to customers throughout the day-ahead market policy consideration process. AWEC "commends BPA on its commitment to consider economic benefits for customers more holistically and under a greater range of potential future scenarios than could be captured by the production cost model scenarios and further appreciates BPA's consideration of trade-offs not fully captured in each scenario."[43] AWEC expresses that Bonneville's costs and benefits analysis helps to place anticipated impacts of the markets in a more realistic context, describing reservations regarding the EDAM congestion allocation to the CAISO BAA and support for the Markets+ GHG design.[44] It is "encouraged by BPA's overarching conclusion that participation in a day-ahead market will result in greater benefits to its customers than business-as-usual."[45] Further, based on Bonneville's consideration of factors, AWEC is "comfortable with an outcome that could result in reduced economic net benefits compared to EDAM in some circumstances, but that are still greater than business-as-usual."[46]

Tacoma Public Utilities (Tacoma) acknowledges that Bonneville responsibly commissioned PCM to partly inform its day-ahead market decision with the recognition of the limitations on the value of those studies.[47] Tacoma expresses the view that "[s]ome stakeholders have encouraged

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[39] *Id.* at 3.
[40] *Id.* (citing WMEG Follow-up Analysis).
[41] WPUDA-031225 at 3.
[42] *Id.*
[43] AWEC-040725 at 2.
[44] *Id.*
[45] *Id.*
[46] *Id.*
[47] Tacoma-040225 at 5.

BPA to elevate the value of those models to the point that BPA would essentially delegate its market decision to a model that is both incomplete in its analysis and highly sensitive to inputs," and it urges Bonneville to reject those suggestions.[48] Tacoma acknowledges that Bonneville's scenario analysis in workshops shows that either EDAM or Markets+ will yield similar incremental benefits per year for Bonneville once realistic assumptions are used in the model.[49]

Snohomish County PUD (Snohomish) agrees with Bonneville that PCM is an important element of the overall analysis, but by no means represents a complete picture. Snohomish asserts that "[t]here are several factors that, taken together, are likely to mitigate if not outweigh these differences."[50] It describes how PCM models have limited ability to consider differences in market design, such as congestion rent allocation and GHG pricing, which significantly impact how market costs and benefits are allocated among participants.[51] Snohomish describes the importance of governance in changes to market rules, which affect how costs and benefits are allocated, how hurdle rate assumptions significantly impact modeling results, and how seams negotiations can reduce barriers to trade between markets.[52] Snohomish states that it "appreciates the thorough evaluation provided by Bonneville of this complex and weighty decision." Snohomish concluded that its "own analysis is consistent with Bonneville's across many key areas. Accordingly, Snohomish supports Bonneville's decision to join Markets+."[53]

Powerex goes further and asserts that "[w]hile PCM models may be useful to provide some high-level directional information around the potential magnitude of dispatch cost savings of a centralized market, they have no value in comparing one market to another when the two markets have fundamentally different approaches to governance and market design."[54] Powerex explains that PCM assumes identical market designs despite crucial design differences in numerous areas including GHG treatment, price formation and congestion allocation.[55]

Similarly, Arizona Public Service Co, Chelan County PUD, Grant County PUD, Powerex, Public Service Company of Colorado, Salt River Project, Snohomish, Tacoma, Tri-State Generation and Transmission Association Inc. and Tucson Electric Power Company (Joint Authors) strongly support the draft policy and acknowledge the "comprehensive, principled, and deliberative process behind those decisions."[56] Regarding PCM analysis, they describe models as one important tool in the evaluation process, but any conclusions must recognize the limitations of

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[48] *Id.*
[49] *Id.* at 4.
[50] Snohomish-040725 at 5.
[51] *Id.*
[52] *Id.* at 5-6.
[53] *Id.* at 6.
[54] Powerex-040725 at 3.
[55] *Id.*
[56] Joint Authors-040725 at 1.

such models. They assert that "[i]n particular, production cost models are poorly suited to reflecting differences in market design, the impact of operator actions, or the incidence of scarcity or other low-probability but high-consequence events."[57]

The Joint Authors posit that "[t]here are dynamic implications of market design that go beyond the direct impacts of market design choices, which cannot be reflected in production cost models."[58] They suggest that a well-designed and well-implemented market is more likely to encourage full participation and to encourage investment in resources and/or transmission. The Joint Authors conclude that a properly governed and designed market will achieve greater benefits for its participants over the longer term.[59]

2) Comments Opposed to the Day-Ahead Market Draft Policy Position

Bonneville received other comments opposed to the direction towards participation in Markets+ primarily based upon PCM analysis results. Many commenters offer strong suggestions that the agency should reconsider its position and adopt a direction towards EDAM. These commenters generally assert that the market design considerations and governance concerns that Bonneville has identified as important factors do not outweigh the PCM results. In general, these commenters suggest that EDAM would provide more economic value to the region as a whole. Some suggest that Bonneville should wait and remain in the WEIM based on its current benefits, and/or there is a need for additional analysis.

The Oregon Public Utility Commission, Oregon Department of Environmental Quality, Washington Utilities and Transportation Commission, Washington State Department of Ecology, and Washington Energy Office at the Washington State Department of Commerce (State Agencies) "recognize the potential benefits of BPA joining a day-ahead market."[60] They also "acknowledge that there is a diversity of views on BPA's market choice, even among BPA's preference customers."[61] They "raised questions about whether the BPA-specific results present a sound business case for BPA joining Markets+ based on BPA's own findings that there are more net benefits if BPA joins EDAM rather than Markets+."[62] When reviewing Bonneville's modeling results, the State Agencies found significant differences in economic outcomes for the region depending on Bonneville's market choice.

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[57] *Id.* at 2.
[58] *Id.*
[59] *Id.*
[60] OR-WA State Agencies-040725 at 1.
[61] *Id.*
[62] *Id.* at 3.

Oregon Governor Tina Kotek and Washington Governor Bob Ferguson support the State Agencies and highlighted State Agencies' comments that regional generation costs are almost $245 million higher and regional load costs are nearly $365 million higher in 2026 alone if Bonneville joins Markets+. They state that SCL could experience cost increases between $6 million and $21 million per year.[63]

SCL states that Bonneville's economic analysis indicates that joining EDAM would offer the largest benefits to its customers, followed by choosing to not join any day-ahead market.[64] It offers key takeaways from Bonneville's analysis that "Markets+ is worse for BPA customers than EDAM by $165-$221 million annually—and these losses persist indefinitely into the future" and "BPA would achieve $79-$130 million in greater benefits annually by continuing participation in the Western Energy Imbalance Market (WEIM) than it would from joining Markets+, even if all other regional market participants join a DAM."[65] SCL also notes that "[u]sing the results of this analysis, City Light estimates BPA's decision to join Markets+ could increase power costs for [its] customers by up to $21 million annually," based on its application of the results to its power products and BPA's rate structure.[66] SCL further states that "[w]hile changing [PCM model] assumptions that reduce the negative impacts of seams and limited connectivity somewhat improved the outcomes for Markets+, there were no scenarios in which the remaining viable Markets+ footprint provided a net benefit to BPA over EDAM."[67] Save Our Wild Salmon Coalition (SOS) echoed SCL's assertion that "a decision to remain in WEIM and not join a day-ahead market produced higher benefits for BPA's customers than joining Markets+."[68]

Several individual commenters stated that "[b]ased on existing analysis, there is clearly a business case for Bonneville to join EDAM."[69] These commenters, as well as hundreds of Sierra Club members,[70] state that studies Bonneville commissioned show that joining Markets+ would increase Bonneville's system costs by at least $65 million over joining EDAM. They argue that the studies show that "maintaining current operations would be better, financially, than joining Markets+."[71] The individual commenters state that based on existing analysis, there is clearly a

[63] OR-WA Governors-040825 at 1.
[64] SCL-040725 at 1.
[65] *Id.*
[66] *Id.* at 4
[67] *Id.* at 2
[68] SOS-040725 at 1.
[69] Dobson-032125; Garman-032125; Reynolds-032125; Stewart-032625; Callaghy-032725 (minor differences); Harland-032825; McMath Walton-032825; Karges-032825; Nimmons-032825; Chin-032825; Brock-032825; Zelasko-032825.
[70] *Id.*; Sierra Club at 1.
[71] *Id.*

business case for Bonneville to join EDAM and ask that Bonneville's final decision on day-ahead markets reflect that case.

NWEC and the Natural Resources Defense Council (NRDC) state that "BPA's analysis shows that joining EDAM delivers substantial benefits by reducing net costs for customers by $60 million compared to current operations."[72] They also state that "joining Markets+ would increase net costs to customers by $108 million." They point to an independently commissioned study from Brattle, that "estimated that net system cost in the Pacific Northwest would decrease by $430 million if BPA joins EDAM and increase by $83 million by joining Markets+."[73] Discussing costs to Bonneville customers, they assert that "BPA's analysis shows that joining EDAM delivers substantial benefits by reducing net costs for customers by $60 million compared to current operations"[74] but "joining Markets+ would increase net costs to customers by $108 million."[75] They conclude that "virtually all utilities and independent power producers rely on and purchase transmission service from BPA" and, "[a]s a result, all electric power consumers in the Northwest benefit from and pay for BPA's power marketing and transmission services and will share in the net gains or losses from BPA's potential participation in a day-ahead market."[76]

PacifiCorp and Portland General Electric (PGE) assert that "BPA has not demonstrated in its Day-Ahead Market Draft Policy Paper how the Agency's decision to leave WEIM and join the Southwest Power Pool's (SPP) Markets+ will be more economically beneficial to its retail customers than joining EDAM or staying in WEIM."[77] PacifiCorp and PGE reach different conclusions by relying on data from two discrete PCM cases. They argue that Bonneville's production costs would increase $130 million per year by joining Markets+ and would be $166 million per year higher should Bonneville join Markets+ instead of EDAM.[78]

They argue that Bonneville overly relies "on statements that these costs are offset because of market design and governance differences between EDAM and Markets+."[79] They contend that "no analysis explains why market design and governance of Markets+ is worth $160 million per

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[72] NWEC-040725 at 1 (citing Draft Policy at 29).
[73] *Id.* (citing Brattle Group, BPA Day-Ahead Market Participation Benefits Study at 14 (Oct. 2024), a*vailable at* https://www.brattle.com/wp-content/uploads/2024/10/BPA-Day-Ahead-Market-Participation-Benefits-Study.pdf).
[74] *Id.* at 4.
[75] *Id.*
[76] *Id.* at 6.
[77] PAC_PGE-040725 at 1.
[78] *Id.* at 3.
[79] *Id.*

year more."[80] They further assert that analysis from CAISO suggests that fast-start pricing and the market power mitigation approach only would result in small differences in WEIM prices.[81]

CTUIR contends that "[j]oining EDAM reduces annual net costs to serve customers by $60 million compared to Business as Usual and $170 million compared to joining Markets+."[82] CTUIR argues that "[j]oining Markets+ would increase system costs by $108 million, assuming EDAM moves forward with the already-announced utilities."[83] It acknowledges that "[i]n Markets+, the cost to serve load is slightly lower, but less revenue from off-system sales does not offset this benefit."[84] CTUIR expresses the view that "BPA has not adequately disclosed the economic impacts to all types of BPA's customers that could arise from joining Markets+ over EDAM."[85]

The Oregon Clean Grid Collaborative (OCGC) points to the Bonneville studies and the Brattle study as "show[ing] that BPA would receive benefits of $65 million in EDAM, as opposed to a loss of $83 million in Markets+."[86] OCGC acknowledges that "[w]hile models are never perfect, the direction and magnitude of the base results are definitive - joining Markets+ is significantly more costly to BPA and its customers than joining EDAM or staying in the WEIM."[87] OCGC requests that Bonneville explain how a "decision to remain committed to Markets+ is supported by a sound business rationale, despite the results of these economic benefits studies overwhelmingly showing otherwise."[88] Finally, it asserts that "[w]here other entities have stepped in to fund such analyses on the region's behalf (i.e., Brattle's BPA Study), the Pacific Northwest sees benefits of $430 million when the region largely participates in EDAM, compared to a loss of $18 million when it participates in Markets+."[89]

The BlueGreen Alliance describes its position "[t]hat the overwhelming majority of these studies show that joining Markets+ results in significantly greater costs and fewer benefits to BPA."[90] It is concerned that Bonneville's draft direction to join Markets+ is "based on an inadequate

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[80] *Id.*
[81] *Id.* at 3-4 (citing CAISO, *Price Formation Enhancements, Analysis on Fast Start Pricing* (Apr, 8, 2024), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Price-Formation-Enhancements-Apr8-2024.pdf; CAISO, *Price Formation Enhancements, Working Group Session #8* (Nov. 16, 2023), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Price-Formation-Enhancements-Nov16-2023.pdf.
[82] CTUIR-040725 at 7.
[83] *Id.*
[84] *Id.*
[85] *Id.*
[86] OCGC-040725 at 8 (citing The Brattle Group, BPA Day-Ahead Market Participation Benefits Study).
[87] *Id.* at 8.
[88] *Id.* at 9.
[89] *Id.* at 10.
[90] BlueGreen Alliance-040725 at 1.

analysis" of economic costs to the region.[91] It urges the agency to "pause its decision on joining a day-ahead market and instead stay in the Western Energy Imbalance Market (WEIM) in the meantime."[92]

Earthjustice argues that "BPA's proposed decision to join Markets+, if finalized, would be unreasonable and contrary to law, because it has not explained why unquantifiable and unanalyzed market design benefits justify foregoing $107 million in annual benefits that BPA could obtain by joining EDAM[.]"[93] To reach these conclusions, Earthjustice relies on the NWEC study conducted by the Brattle Group and prepared for NWEC.[94] Earthjustice asserts that Bonneville inadequately explains how Markets+ would provide financial benefits that are greater than business as usual because Bonneville is not able to "decisively quantify" what it views as superior market design issues such as governance, congestion revenue allocation, GHG accounting, and fast-start pricing.[95]

RNW recognizes that the benefits of regional markets are linked to the structure, depth, footprint, and governance of the market in question.[96] It emphasizes that "ample evidence that a single footprint market with greater geographic and resource diversity is far superior," and cites concerns about fragmentation causing unnecessary costs.[97] RNW argues that if the Western Interconnection is divided into two separate markets, benefits from increased reliability, affordability, and resource diversity would be diminished.[98] RNW states that "[r]egarding geographic diversity, the footprint of the DAMs has evolved throughout the workshop process, and it is not clear which geographic footprint BPA is specifically identifying to support its leaning towards Markets+."[99]

RNW argues that if Bonneville "cannot say conclusively that entering into Markets+ at this incredibly early stage is not empirically the best decision for its customers and the region, then there is no reason for it to act now while significant uncertainties and questions about both DAMs remain."[100] RNW believes it is insufficient for Bonneville to conclude that "[w]hile several market design issues described above, such as congestion revenue allocation, GHG

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[91] *Id.*
[92] *Id.*
[93] Earth Justice-040725 at 25.
[94] *Id.* at Exhibit 4.
[95] *Id.*
[96] RNW-040725 at 2.
[97] *Id.* at 14 (citing Kotek, Tina, Bonneville Power Administration's Day-Ahead Market Participation Evaluation (Mar. 28, 2024), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2024/oregon-governor-kotek-032824-governor-kotek-letter-to-bpa-administrator-hairston.pdf).
[98] *Id.* at 3.
[99] *Id.* at 19.
[100] RNW-040725 at 14.

accounting, and fast start pricing cannot be decisively quantified, BPA determines the Markets+ design is likely to provide economic benefit and partially offset the financial benefits attributed to EDAM by the PCM studies."[101] RNW concludes that "the economic justification [Bonneville] relies upon is inherently inaccurate due to its premature nature."[102]

Amazon Web Services comments that "[t]he justification provided by Bonneville at this time is not sufficient to meet the important threshold of ratepayer protection, particularly in light of other market options available, some of which have been reported by Bonneville studies to save customers $100s of millions."[103] Amazon Web Services "believes more analysis is needed to fully understand these conclusions and provide ratepayers and stakeholders greater assurances that these benefits of Markets+ will materialize."[104] Amazon Web Services concludes that "[w]hile remaining in the WEIM may not be a viable long-term option . . . [it] would provide known, continued benefits while allowing Bonneville to gather all the necessary information and metrics to truly evaluate which DAM directly will provide the best outcome for Bonneville, its customers, and the region as a whole.

Evaluation

A. Context for Magnitude of Benefits

Bonneville recognizes that there are substantial differences of opinion regarding the agency's takeaways from the PCM analyses. Bonneville and commenters were able to assess more than 50 PCM case results based on the WMEG analysis and supplemental Bonneville analysis conducted by E3.[105] Indeed, NWEC, RNW, NIPPC, Pacific Northwest Generating Cooperative, and Gridlab even commissioned an additional PCM analysis, the Brattle "BPA Day-Ahead Market Participation Benefits Study."[106]

Some commenters, such as PacifiCorp and PGE, suggest that based on individual PCM case results out of 50 cases studied, Bonneville's decision amounted to -$130 to -$166 million per year in lost revenue. Also based on individual case results, SCL suggests that Bonneville's decision amounts to -$79 to -$221 million per year. Bonneville disagrees with these assertions and finds that there is price convergence between the two market projections based on the modeling assumptions, with a difference as low as $14 million. As discussed below in subsection C: 1) Bonneville's PCM results showed multiple scenarios in which the difference in

[101] *Id.* at 13-14 (citing Draft Policy).
[102] *Id.* at 15.
[103] AWS-040725 at 1.
[104] *Id.* at 2.
[105] *See* Draft Policy at 26, Table 4.
[106] The Brattle Group, BPA Day-Ahead Market Participation Benefits Study.

benefits was significantly smaller than the highlighted range; and 2) PCM results do not reflect the potential benefits of the numerous governance and design differences considered by Bonneville and commenters in support of Bonneville's decision.

To put into perspective the figures that SCL, PacifiCorp and PGE point to in discrete PCM case results, the costs or benefits would be one component of the agency's over $5 billion annual revenue requirement.[107] Bonneville's Fiscal Year 2026 Power Revenue Requirement is $3,451,708,000,[108] and provides the basis for recovering generation-related costs associated with the FCRPS, including the federal investment in hydro generation, fish and wildlife, conservation costs, non-federal power supply, and market purchases.[109] Bonneville's Fiscal Year 2026 Transmission Revenue Requirement is $1,626,696,000,[110] and provides the basis for rates to recover FCRTS costs, including recovery of the federal investment in transmission and transmission-related assets, operations and maintenance, and expenses associated with transmission and ancillary services.[111]

Bonneville's Power revenue uncertainty, largely driven by its power net secondary revenue uncertainty, has a standard deviation of approximately $250 million per year and a range of $2.2 billion.[112] This is not to diminish the significance of potential costs to Bonneville, but it is an important frame to place around the overarching strategic decision, the various other market design considerations, and the limitations of the PCM results highlighted by Bonneville and cited by several parties.

Considering the general potential range of benefits identified by parties including PacifiCorp and PGE, potential costs or benefits of ~$150 million could amount to roughly +/- 3% of Bonneville's annual revenue requirement. As described below, Bonneville does not share the view that Markets+ participation would result in increased costs or lost benefits, but these figures should be considered in context. The approximately $150 million falls within Bonneville's range of net secondary revenue uncertainty.[113] Notwithstanding the potential range of costs and benefits, Bonneville understands that it is imperative to maintain competitive power and transmission rates.

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[107] BP-26 rate case documents are available at https://proceedings.bpa.gov/Home/LoadDocuments?RateCaseId=38.
[108] Power Revenue Requirement Study Documentation, BP-26-E-BPA-02A, Table 1A.
[109] Power Revenue Requirement Study, BP-26-E-BPA-02.
[110] Transmission Revenue Requirement Study Documentation, BP-26-E-BPA-09A, Table 1-1.
[111] Transmission Revenue Requirement Study, BP-26-E-BPA-09A; Transmission Revenue Requirement Study Documentation, BP-26-E-BP-05A.
[112] Power and Transmission Risk Study, BP-26-E-BP-05-CC01, at 89, Table 1 (Rev Sim Net Revenue Statistics for FY 2026 through FY 2028); *see also* Transmission Revenue Requirement Study Documentation, BP-26-E-BP-05A.
[113] Power and Transmission Risk Study, BP-26-E-BPA-05-CC01, at Table 1.

B. Footprint Composition

Many commenters with differing views recognize, as explained in the Draft Policy, that PCM results are highly dependent on the composition of the market footprint (i.e., which load, generation, and transmission are included in the market optimization).[114] Identifying a market footprint requires assumptions about which market a utility may choose to join. The footprint composition brings together the resources that will be optimized to serve load at the least cost and is constrained by the transmission connectivity that is utilized by the market to deliver the footprint resources to load. Adjusting the market participants, and therefore changing the footprint, can offer additional load to serve, additional generators to serve load, and transmission connectivity assumptions that expand the possible market optimization solutions.

In section 5.1 of the Draft Policy, Bonneville concluded that the PCM results are highly dependent on the market footprint, and it is not possible to predict with absolute certainty which footprint will ultimately materialize.[115] Bonneville described how footprint and a range of assumptions are required to produce effective modeling, and while PCM results are useful in providing market participation projections, they do not represent precise expected outcomes.[116] Recognizing that the market footprint studied is a primary driver of PCM results and the cost and benefit estimates, Bonneville discusses various market footprint scenarios in turn.

First, regarding a west-wide market, Bonneville agrees with OCGC, Southern California Edison (SCE), and others that Bonneville sees the highest financial benefit from participating in a single west-wide market.[117] SCL also uses Bonneville's west-wide market results to determine the higher end of its comparison of lost benefits ($221 million). SCL makes additional arguments regarding EDAM expansion approximating west-wide benefits, which are discussed further in Issue #3, hurdle rates. However, as explained in section 5.1.1.4.2 of the Draft Policy, which discussed supplemental analysis footprints, the agency determined that a single west-wide market is not a likely footprint due to market participation indications from BAs.[118]

PPC and Tacoma both agreed with Bonneville's expectation, with PPC stating that "a West-wide EDAM is very unlikely"[119] and Tacoma stating that "[w]hile a single market scenario for the Western Interconnection is a laudable aspiration, current dynamics and commitments make that scenario impossible."[120] Tacoma goes further, recognizing that "[t]he development of two day-

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[114] *See, e.g.*, PAC_PGE-040725 at 3; PPC-040725 at 11; RNW-040725 at 15; Snohomish-040725 at 5; Tacoma-040225 at 4; Joint Authors-040725 at 2.
[115] Draft Policy at 28-29.
[116] *Id.* at 17-18.
[117] OCGC-04725 at 7; SCE-040725 at 1.
[118] Draft Policy at 25-29.
[119] PPC-040725 at 11.
[120] Tacoma-040225 at 6.

ahead energy markets in the Western Interconnection has resulted from decisions of many entities, and market footprint is not within the exclusive control of BPA or any other single entity."[121]

Second, regarding BAU, E3 modeled the operational and trading world as it exists today, with only bilateral trading in the day-ahead but no centrally organized day-ahead market, and real-time energy imbalance markets. Bonneville does not consider BAU a likely future scenario considering the many utility declarations towards participation in a day-ahead market. As described in the Draft Policy, "[w]ith many entities in WECC evaluating participation and declaring intent to join organized day-ahead markets, the bilateral world, as it is today, is not expected to persist."[122]

Bonneville nevertheless included modeled costs and benefits relative to BAU to provide a sense of the magnitude and direction of the impact day-ahead market participation has relative to today. BAU does not represent a realistic future scenario."[123] RNW asserted that "the initial WMEG study and the update found that the BAU case where BPA remains in the WEIM without joining a DAM is better economically than joining Markets+ at this time."[124] While this could be true in the short-term, Bonneville finds that the BAU scenario does not present realistic future results because as others join day-ahead markets, Bonneville would experience decreased access to trading partners in the day-ahead timeframe that provides valuable operational flexibilities and revenue for the agency.

Third, the WEIM-only cases assume that Bonneville remains outside day-ahead markets while continuing to be a WEIM participant, while other entities in the Western Interconnection participate in varying day-ahead market footprints.[125] SCL maintains that Markets+ is worse for Bonneville customers, and WEIM-only is a better option for BPA customers than entering Markets+.[126] Alternatively, PPC contends that the assumed hurdle rate in the benefits of WEIM participation and status quo are overstated relative to Markets+.[127] Several commenters, including the BlueGreen Alliance and Amazon Web Services, argue that Bonneville should continue to participate in the WEIM because it has provided significant annual benefits and/or in order to have more information to assess day-ahead market participation.[128]

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[121] *Id.*
[122] Draft Policy at 23.
[123] *Id.*
[124] RNW-040725 at 16 (citing Seattle City Light Comments re: BPA Day-Ahead Market Participation Workshop #9 at 3 (Dec. 13, 2024))
[125] Policy at 29.
[126] SCL-040725 at 10.
[127] PPC-040725 at 8.
[128] BlueGreen Alliance-040725 at 1; AWS-040725 at 1.

While these arguments may be asserted for both the BAU and WEIM-only case results, Bonneville's assessment is that although the WEIM-only case initially projects incremental benefits in one of the footprints tested, it assumes that other utilities join day-ahead markets, which would similarly result in a gradual loss of trading partners. Powerex agrees, stating "any comparison to the status quo will fail to reflect that many of Bonneville's trading partners are making their own choices to join a day-ahead market and therefore doing nothing would leave BPA with limited day-ahead bilateral trading opportunities going forward."[129] Further, Powerex states that "[a]s a large and growing number of entities plan to join a day-ahead market in the near-term, there is a growing risk that Bonneville will face reduced trading liquidity in bilateral markets when seeking to make short-term transactions to help manage the federal hydro system."[130] Bonneville maintains the view that "the reduction in access to trading partners may significantly degrade these results and make remaining a WEIM-only participant an unsustainable option in the long term."[131]

Finally, Bonneville compared likely market footprints as utilities made declarations towards participation in EDAM or Markets+. Alt 4A was designed to reflect utilities' market participation indications available at the time of the supplemental E3 analysis. After E3's analysis was largely complete, the Alt 2NV was added at the request of commenters to represent a scenario in which Bonneville is in EDAM while the Desert Southwest (which is unlikely to join EDAM) participates in Markets+.

For reference, the Alt Split 4A and Alt Split 2NV footprints are included in Table 1 below.

Table 1 | Updated footprints for additional E3 studies

Alternative Split 2NV	Alternative Split 4A
 **EDAM:** California, PacifiCorp, NV Energy & all Pacific Northwest BAAs **Markets+:** BAAs located in the Desert Southwest and Rockies	 **EDAM**: California, PacifiCorp, NV Energy, Idaho Power, Portland General Electric, Seattle City Light **Markets+:** Rest of US WECC and British Columbia ***Reflects current day-ahead market declarations & leanings***

[129] Powerex-040725 at 4.
[130] *Id*. at 1.
[131] Policy at 31.

C. Assessment of PCM Case Results

Regarding the projected costs and benefits of participation, Bonneville acknowledges the wide range of E3 PCM analysis results ranging from $26 million in costs to $251 million in benefits.[132] Bonneville also acknowledges that some commenters, including OCGC, point to the Brattle study, which estimated that Bonneville's net system cost decreases by $65 million from joining EDAM and increases by $83 million from joining Markets+.[133]

Beyond the footprint modifications, Bonneville also commissioned supplemental analysis of sensitivities to market-to-market hurdle rates. Bonneville conducted a supplemental analysis of the Markets+ two-market scenarios to reflect declining hurdle rates in Alt Split 4A and Main Split. PPC and other commenters observed that the higher hurdle rates in the initial WMEG study exceeded what they would expect to occur based on existing contracts for transmission rights and the continued use of long-term firm transmission in both markets.[134]

E3 modeled declining hurdle rate sensitivities for the supplemental analysis, and those hurdle rates were applied to the Alt Split 4A footprint and the Main Split. All other footprints studied in the supplemental analysis continued to use the higher hurdle rate assumed in the original WMEG study. The west-wide market footprint had a hurdle rates set to zero because it is a single market (and therefore there is no "hurdle" i.e., market-to-market friction). The declining hurdle rate sensitivities in the Alt Split 4A M2M, Alt Split 4A M2M2, and Alt Split 4A M2M3 are discussed further in Issue #3 on hurdle rates.

The table below compares Bonneville's projected results for footprint Alt Split 4A, with results for Alt Split 4A WEIM-Only, Alt Split 2NV, Alt Split 4A M2M, Alt Split M2M2, and Alt Split M2M3.[135] The hurdle rates for Markets + exports in the M2M sensitivity cases in table 5 were; **M2M** - $10.50/MWh (DA) and $7.50/MWh (RT), **M2M2** - $7.50/MWh (DA and RT), **M2M3** - $5.25/MWh (DA and RT).

Table 2 | Consolidated supplemental case results for Alt Split 4A, Alt Split 4A WEIM Only, Alt Split 2NV, Alt Split 4A M2M, Alt Split 4A M2M2, and Alt Split M2M3

[132] WMEG Follow-up Analysis at 13, 17.
[133] BPA Day-Ahead Market Participation Benefits Study at 11; OCGC-040725 at 8.
[134] PPC-040725 at 8.
[135] The table summarizes the main footprints identified by Bonneville and commenters as likely outcomes and is included in Table 5 on page 27 of the Policy.

	A	B	C	D	E	F	G
	BPA Day-Ahead Market →	Markets+	No DAM Market WEIM-Only	EDAM	Markets+	Markets+	Markets+
1		Alt Split 4A (2026)	Alt Split 4A BPA WEIM-Only (2026)	Alt Split 2NV (2026)	Alt Split 4A M2M (2026)	Alt Split 4A M2M2 (2026)	Alt Split 4A M2M3 (2026)
2	**Cost/Benefit Category**				**Declining Hurdle Rates**		
3	Load Costs	739	908	873	818	874	910
4	Gen Rev	-835	-1129	-1155	-987	-1097	-1166
5	Gen Costs	131	131	131	131	131	131
6	Congestion Rev	-65	-69	-44	-59	-56	-57
7	GhG Rev	0	0	0	0	0	0
8	**NC w/o Wheel**	**-30**	**-160**	**-196**	**-97**	**-148**	**-182**
9	Δ Alt 4A | Load Costs	--	169	134	79	136	171
10	Δ Alt 4a |Gen Rev	--	-294	-320	-152	-262	-331
11	Δ Alt 4A |Congestion Rev	--	-4	21	6	9	8
12	Δ Alt 4A | GhG Rev	--	0	0	0	0	0
13	**Δ Alt 4A |Net Cost w/o Wheel**	**--**	**-130**	**-166**	**-67**	**-118**	**-152**
14	**Δ Alt 4A M2M's vs Alt Split 4A WEIM-Only Net Cost w/o Wheel**	--	--	--	**63**	**12**	**-22**
15	**Δ Alt 4A M2M's vs Alt Split 2NV Net Cost w/o Wheel**	--	--	--	**99**	**48**	**14**

These PCM cases were the most stakeholder-cited cases in responses to the Draft Policy.

Table 2 summarizes the PCM case results highlighted by commenters including PacifiCorp, PGE, and SCL as demonstrating better benefits for Bonneville in the Alt Split 4A BPA WEIM-only scenario or 2NV EDAM participation scenarios (columns B, C, D), as well as additional cases released by Bonneville showing the improved results of Markets+ in lower hurdle rate scenarios (columns E, F, G). As demonstrated in row 14 of Table 2, lowering the hurdle rate in the Alt Split 4A case improves the results relative to the BPA WEIM-Only case, with the lowest tested hurdle resulting in $22 million more benefit in Markets+ participation (as depicted in Row 14, Columns E, F, and G). Similarly, the adjusted hurdle rates of each Alt Split M2M case begin to converge to the Alt Split 2NV EDAM participation, ultimately resulting in a relatively small difference of $14 million (as depicted in Row 15, columns E, F, and G). While commenters focus on the limited case scenario results in columns B, C, and D, a comparison of the results reinforces Bonneville's conclusions that market footprint and hurdle rate assumptions are primary drivers of the expected benefits in the PCM cases.

PacifiCorp and PGE interpret the Alt Split 4A and Alt Split 2NV cases differently from BPA, asserting:

> When comparing BPA's production cost modeling results for Alt Split 4A with BPA remaining in WEIM, which today is the closest case to a base case, and the results for Alt Split 4A with BPA joining Markets+, BPA's production costs increase $130 million per year by joining Markets+. The Alt Split 2NV case, which likely

> represents the most accurate EDAM footprint, models BPA's production costs to be $166 million per year higher should BPA join Markets+ instead of EDAM.[136]

As explained above, Bonneville disagrees with PacifiCorp and PGE's characterization that this single case represents a likely outcome for Bonneville. Alt Split 4A BPA WEIM-only depicts a scenario in which the West is divided between two day-ahead markets while Bonneville alone elects not to participate in a day-ahead market. Bonneville does not consider the WEIM-only results a reasonable future operational scenario because the agency would lose significant access to trading partners in the day-ahead horizon over time. Bonneville must maintain access to sufficient trading partners for operational flexibility and to maximize revenue.

Accordingly, Bonneville disagrees with SCL, PacifiCorp and PGE conclusions that a comparison of BPA WEIM-only with Alt Split 4A demonstrates that BPA WEIM-only participation would result in better benefits for Bonneville than participation in Markets+ in all scenarios. Not only does this comparison present a misleading picture of a likely market footprint, but it also fails to consider a range of hurdle rates that provide additional insight into anticipated market outcomes.

Bonneville emphasizes that as the hurdle rate was reduced, footprint 4A results ultimately achieved forecasted benefits above the WEIM-only results (see row 14, columns E, F, G). PPC agrees with Bonneville, stating that the higher hurdle rates appear to "[s]ignificantly overstate the role of market footprint in economic benefits" and "[o]verstate the economic benefits of WEIM participation and the status quo relative to Markets+."[137] Bonneville provides further analysis of hurdle rate variations in Issue #3.

Bonneville also disagrees with PacifiCorp and PGE's characterization of Bonneville's benefits as $166 million per year higher should Bonneville join EDAM instead of Markets+. SCL based its projected benefits of $165 EDAM over Markets+ on analysis of E3 PCM case scenario spreadsheets publicly posted by Bonneville and a workshop response regarding the hurdle rate.[138] Again, these conclusions rest upon comparing the Alt Split 2NV EDAM Scenario to Alt Split 4A alone, which presents a misleading picture because it is derived through a calculation that only considers the highest hurdle rate level rather than a range of hurdle rates.

PacifiCorp and SCL characterizations rest upon the initial hurdle rates modeled in the WMEG analysis, despite the fact that Bonneville and the vast majority of its public customers share the view that the initial hurdle rate assumptions were potentially inflated insofar as they did not

[136] PAC_PGE-040725 at 3.
[137] PPC-040725 at 8.
[138] SCL-040725 at 35-36 n.95 ("City Light relied on the spreadsheets provided by E3 to calculate the differences. Numbers calculated by finding the difference between the "Net Cost Excl Wheeling" values of the EDAM cases (EDAM Bookend and Alt Split 2NV) and Markets+ (Alt Split 4A) for 2026, 2030, and 2035.").

consider existing contracts for transmission and the likelihood of continued use of firm transmission in both markets.[139] For this reason, PPC asserts that "this is not an accurate reflection of what is expected to occur."[140] Nevertheless, SCL maintains that there were no scenarios in which the remaining viable Markets+ footprint provided a net benefit to Bonneville over EDAM, even when the negative impacts of seams and limited connectivity somewhat improved the outcomes for Markets+.[141] However, other customers interpreted the results more similarly to Bonneville. For instance, Tacoma states, "EDAM or Markets+ will yield similar incremental benefits per year for BPA, once realistic cross-market transactional friction assumptions are used."[142] Like PPC and Tacoma, Bonneville firmly believes that analysis of a range of cross-market transactional friction (i.e., hurdle rate) assumptions provide a better basis for comparison of potential real-world outcomes than focusing on a single PCM case result.

SCL goes further with its conclusions from this single PCM case to "estimate[] BPA's decision to join Markets+ could increase power costs for [its] customers by up to $21 million annually."[143] Again, Bonneville disagrees with these numbers because they represent a comparison to a scenario with a very high hurdle rate, and do not account for the costs and benefits of other market design features. Issue #3 contains more discussion of hurdle rate impacts on PCM analysis.

Along with consideration of other market design elements, Bonneville's policy position is based upon the conclusion that analysis of the likely Alt Split 4A footprint comparison scenarios of Markets+ to WEIM-only and of Markets+ to EDAM (Row 14, Column E, F and; Row 15, Column E, F, G) show improved benefits of Bonneville participation in Markest+ compared to BAU and BPA WEIM-only. Bonneville emphasizes that E3's supplemental analysis regarding hurdle rate assumptions was necessary and appropriate considering commenter feedback that the WMEG study had potentially inflated hurdle rates leading to unlikely outcomes projected for the study footprints. Bonneville's hurdle rate analysis is explained further in Issue #3.

In addition to the improved results for Markets+ with lower hurdles, Bonneville also observes that the EDAM highest net benefit (Alt 2NV) was influenced by higher market prices that drove up projected generation revenue (offsetting the higher costs to serve load). WPUDA comments that "EDAM's superior economic benefit depends, long-term, on BPA remaining surplus and EDAM's maintaining higher locational marginal prices," which is "questionable in the long-term."[144] As WPUDA suggests, there is no guarantee, and in fact there is evidence against the

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[139] PPC-040725 at 8-11.
[140] *Id.* at 11.
[141] SCL-040725 at 2.
[142] Tacoma-040225 at 5.
[143] SCL-040725 at 4.
[144] WPUDA-031225 at 3.

assumption that Bonneville will continue to have significant surplus generation to market out of the region and receive such forecasted increases in revenues.

PPC similarly states "[I]t is important to note that the economic analysis essentially shows that prices in the Northwest will be higher if BPA joins EDAM." PPC suggests that "[i]n the production cost modeling performed on BPA's behalf, greater benefits for the agency are based on the assumption that it will have substantial excess generation." PPC observes that "[w]hile historically BPA had excess generation to market which has resulted in secondary revenues that have reduced power rates, the extent of surplus generation available for uses other than serving its preference customers under the coming Provider of Choice contracts and further into the future is uncertain."[145]

With this context, PPC asserts that "[s]electing a future where Northwest prices are higher, simply due to a price convergence with California, is not a clear benefit for BPA, its customers, or Northwest ratepayers as a whole."[146] It concludes that "[t]his uncertainty emphasizes the importance of establishing a balanced market that sends clear and accurate price signals to participants . . . [and] also emphasizes some of the potential risks around using the production cost modeling results as the sole criteria for determining BPA's market participation."[147]

Indeed, Bonneville's 2024 White Book on Pacific Northwest loads and resources concludes that between 2025 to 2034, the agency is projected to have loads of roughly 7,500 to 8,500 MW per month. These load levels coupled with available supply (i.e., firm power generation) would result in projected deficits of 79 aMW to 303 aMW under firm water conditions. It is important to note that the annual energy surplus can increase by over 4,000 aMW under better water conditions, while monthly surplus or deficit positions can vary by close to 7,000 aMW within the same year. Therefore, the PCM analysis assumption of high locational marginal prices (LMPs) driving up generation revenues is heavily dependent on water year conditions relative to Bonneville's firm power customer load.[148] Bonneville's customers also raise concerns with this trend, such as WPUDA citing Pacific Northwest Utilities Conference Committee data to conclude that "BPA will be challenged to remain surplus given that load growth is projected to increase 30% by 2035[149] [and that] BPA's own analysis indicates a tightening of its load-resource balance and even near-term deficits under firm water conditions."[150] Bonneville must base its day-ahead market participation direction not on assumptions of large amounts of surplus generation as

[145] PPC-040725 at 12.
[146] *Id.*
[147] *Id.*
[148] Bonneville Power Admin., 2024 Pacific Northwest Loads and Resources Study at 23 (Aug. 2024), *available at* https://www.bpa.gov/-/media/Aep/power/white-book/2024-white-book.pdf.
[149] WPUDA-031225 at 3 (citing Pacific Northwest Regional Forecast of Power Loads and Resources, 2024 through 2034, Pacific Northwest Utility Coordinating Council (Apr. 2024)).
[150] *Id.*

modeled in the PCM analysis, but on its projections of potential need to acquire resources to serve firm power load on a long-term or short-term basis.

Further, the EDAM cases project higher prices to serve load based on higher LMPs. This could drive up prices for long-term firm power customers if Bonneville or individual customers must acquire power from the market in the short-term to serve load. For these reasons, the increased generation revenue modeled in the EDAM analysis may be misleading because Bonneville is less likely to have surplus generation to market out-of-region in the future, and the increased LMPs for load service may increase the price of power to serve Bonneville's firm power loads. As WPUDA notes, "For PUDs and other BPA customers that exceed their Tier 1 allotment of cost-based electricity from the Columbia River Hydropower System, higher costs for Tier 2 or market power will reduce EDAM's incremental benefit."[151] These situational factors are not captured in PCM analysis, and Bonneville must consider PCM results alongside its existing power forecasting and long-term firm power sales obligations. As discussed below, commenters place different weight on the PCM results vis-à-vis market design elements.

D. Consideration of Other Market Design Impacts

Bonneville emphasizes that while valuable, PCM studies do not reflect various market design elements, which weigh heavily on the value proposition. Commenters who advocate for Bonneville to participate in EDAM indicate that they do not expect the design elements in Markets+ to outweigh the potential benefits of EDAM projected in the PCM results. PacifiCorp and PGE state that "[i]t is not evident how the Agency's expressed preference for Markets+ governance and market design outweighs the significantly reduced economic advantages when compared to EDAM participation."[152] They assert that "no analysis explains why market design and governance of Markets+ is worth $160 million per year more."[153] SCL similarly suggests that "[t]he differences in market design are minimal and unlikely to produce meaningful benefits that outweigh the losses BPA would incur by joining Markets+."[154]

But there are many examples of design elements that cannot be appropriately modeled in PCM and have the potential to outweigh PCM result differences, either through improved financial or non-financial outcomes. For instance, PPC suggests that "the actual observed consequences of unbalanced governance and market design appear to be on the magnitude of hundreds of millions of dollars annually."[155] WPUDA similarly states that "[t]he benefits and costs that actually flow to BPA customers are likely to be affected by factors the Production Cost Modeling did not fully

[151] *Id.* at 2.
[152] PAC_PGE-040725 at 3.
[153] *Id.*
[154] SCL-040725 at 37.
[155] PPC-040725 at 11.

evaluate."[156] Tacoma also comments that "[p]roduction cost projections are an important component of evaluating day-ahead market options . . . [b]ut they are only one component that must be balanced against independent governance and other market designs."[157] Snohomish echoes these sentiments, concluding that "[p]roduction cost models have limited ability to take into account differences in market design, such as congestion rent allocation and GHG pricing described above, that can significantly impact how market costs and benefits are actually allocated among participants."[158]

Some commenters consider the value proposition of market design relative to PCM results. For instance, Tacoma notes that "production cost modeling does not fully evaluate the benefits of joining a market with a common resource adequacy standard," and asserts that "this difference in market design results in a greater risk within EDAM that participants could be forced to over-procure capacity, a result with costs that could potentially surpass any production cost savings." Similarly, regarding price formation and fast-start pricing, PPC decries the lack of fast-start pricing in EDAM, estimating that "implementing fast-start pricing in the CAISO market would increase revenues to those with surplus generation in the Pacific Northwest (including BPA) by $200 million annually."[159] And with regards to congestion charges, PPC describes a value shift during a 5-day winter weather event, where "CAISO congestion revenue rights holders collect[ed] over $100 million of congestion revenue for congestion occurring on a jointly funded and operated multi-state transmission asset."[160] These market design elements and their cost impacts are discussed further in the sections 5.2.1 to 5.2.5.

Considering the PCM analysis alongside other factors, AWEC was "encouraged by BPA's overarching conclusion that participation in a day-ahead market will result in greater benefits to its customers than business-as-usual." Bonneville, like AWEC, "is comfortable with an outcome that could result in reduced economic net benefits compared to EDAM in some circumstances, but that are still greater than business-as-usual."[161] Bonneville has assessed the PCM results and their differing assumptions, and has reached the conclusion that no single PCM case can fairly approximate real-world outcomes, which must also be considered alongside the costs and benefits of market design elements.

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[156] WPUDA-031225 at 2.
[157] Tacoma-040225 at 5.
[158] Snohomish-040725 at 5.
[159] PPC-040725 at 11 (citing Powerex and PPC, The Importance of Fast Start Pricing in Market Design: Including the Cost of Starting and Operating Natural Gas Peaking Units in Wholesale Market Prices (June 2022), *available at* https://www.ppcpdx.org/the-importance-of-fast-start-pricing-in-market-design-june-2022/).
[160] *Id.* (citing Energy GPS LLC, Analysis of Malin Congestion Rents Aug. 2020 and Jan. 2024 Scarcity Events (Mar. 8, 2024), *available at* https://www.pnucc.org/wp-content/uploads/2024-03-CongestionRent-combined.pdf (presentation to Pacific Northwest Utilities Conference Committee)).
[161] AWEC-040725 at 2.

Decision

Based on the PCM analysis and the market design elements discussed below, Markets+ is the best path forward for the agency and its customers. Bonneville expects participation in a day-ahead market to offer better than BAU or WEIM only participation, particularly over the long term. Bonneville stresses that basing a market decision solely on PCM results would be too narrow of a focus and would carry risk of ignoring important market design elements that greatly impact financial outcomes. PCM studies do not reflect various market design elements such as GHG pricing programs, market power mitigation, out-of-market actions, governance, and market bid caps.[162] These topics are examined in Sections 5.2.2 to 5.2.5 of the Policy. As discussed herein, Bonneville recognizes that minimizing hurdles and seams issues will be crucial to achieving this anticipated outcome and will be mutually beneficial to both markets.

ISSUE 3: Whether Bonneville appropriately considered hurdle rates in its PCM Analysis

Draft Policy Position

In Section 5.1.1.1 of the Draft Policy, Bonneville explained that PCM must assume the cost associated with transmission within a market (usually assumed to be zero) and the cost of transmission and other incremental "friction"[163] between markets, which is captured in the PCM analysis as a "hurdle rate." The hurdle rate component of a PCM analysis is incorporated to address the costs associated with two market footprints, such as costs with sales across markets and price divergence between markets.

Public Comments

Some commenters argue that even with lower hurdle rates, Bonneville's analysis does not support a draft policy direction towards Markets+ participation. The State Agencies suggest that "[e]ven with the lowest market-to-market hurdle rates tested for BPA-in-M+, there still would not be as much benefit as BPA-in-EDAM provides per BPA's results."[164] They argue that Bonneville only studied reduced hurdle rate footprints for Bonneville as a Markets+ participant,

[162] *Id.* at 18.
[163] Market-to-market friction attempts to approximate the reduced willingness of a seller to sell into another market footprint. This reduced willingness may be due to additional rules the seller must comply with, additional financial risk the seller takes on, additional costs the seller must recoup, etc. The price differential between the markets must be larger than the assumed "hurdle rate" for the PCM analysis to allow for transactions between the markets.
[164] OR-WA State Agencies-040725 at 3.

and “if lower hurdle rates were similarly applied to BPA-in-EDAM as well, those benefits would likely grow, like was seen in the BPA-in-M+ split footprint.”[165]

SCL rejects other public power customer assertions and Bonneville’s conclusion that lower hurdle rate scenarios may likely be lower than those initially modeled by E3 in the WMEG analysis which serve as the basis for the Alt Split 4A scenarios.[166] During the November 4, 2024, Stakeholder Workshop, SCL asked what the outcome might have looked like if BPA had applied the same hurdle assumptions to the EDAM scenario (Alt Split 2NV) that it did to Markets+.[167] It states that E3 indicated results would likely approach the base-case results for the West-wide market scenario.[168] SCL notes that “[w]hile changing assumptions that reduce the negative impacts of seams and limited connectivity somewhat improved the outcomes for Markets+, there were no scenarios in which the remaining viable Markets+ footprint provided a net benefit to BPA over EDAM.”[169]

On the contrary, Tacoma considers the higher hurdle rates unrealistic, citing “results presented in BPA’s workshops show that either EDAM or Markets+ will yield similar incremental benefits per year for BPA, once realistic cross-market transactional friction assumptions are used.”[170] The Joint Authors express that “modeling results are highly sensitive to ‘hurdle rate’ assumptions between the markets, which are used to reflect not only objective applicable charges, but also as a subjective representation of ‘friction.’”[171] In addition, Powerex acknowledges that PCM models “[a]re highly dependent on input assumptions such as hurdle rates that can produce outcomes that inaccurately predict that limited trade will occur between markets.”[172]

PPC supports Bonneville’s position and expresses concerns that the higher hurdle rates were unrealistic. PPC understands the assumed hurdle rates are meant to capture transmission costs and transactional friction costs but asserts that “the level of assumed hurdles exceeds what [it] would expect to occur based on the continued use of long-term firm transmission in both markets.”[173] PPC explains that an assumed hurdle that increases from no hurdle when BPA is modeled in EDAM to the OATT Rate + $8/MWh of friction when Bonneville is modeled in Markets+ is not an accurate reflection of what is expected to occur. PPC contends that under Markets+, the overwhelming majority of Bonneville schedules modeled already include the

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165 *Id.*
166 SCL-040725 at 27.
167 *Id.*
168 *Id.*
169 *Id.*
170 Tacoma-040225 at 5.
171 Joint Authors-040725 at 2.
172 Powerex-040725 at 3.
173 PPC-040725 at 8.

OATT rate, so the OATT rate should not be assumed as an incremental additional cost in the hurdle rate.[174]

Therefore, PPC stresses that hurdle rates, which are not applied in the Single West-Wide Market footprint, may be "driving analytical outcomes that are not likely to actually occur."[175] PPC describes how PCM analysis of existing data based on the WEIM resulted in prices "essentially behaving in the opposite manner of what is modeled in the study."[176] PPC asserts that this real-world data "demonstrates that the multitude of factors not fully reflected in the production cost model—such as fast-start pricing, scarcity pricing, and others—are having significantly larger impacts on prices than reduced hurdle rates and wider footprints."[177]

PPC concludes that the higher hurdle rates assumed in most PCM scenarios appear to both "1) significantly overstate the role of market footprint in economic benefits, and 2) overstate the economic benefits of WEIM participation and status quo relative to Markets+."[178] PPC concludes that assumption has "an outsized impact on results." PPC discusses Bonneville's Figure 5 on hurdle rate sensitivities, identified Alt Split 2NV and Alt Split 4A as most likely to occur, and concludes that in PCM scenarios "where the assumed hurdle rates were reduced, the benefits resulting from BPA's participation in different modeled footprints converged."[179]

Evaluation

As described in the Draft Policy, hurdle rate assumptions are an important and influential component in PCM. PCM analysis based on a single market does not include a hurdle rate. Multi-market footprints, modeled with hurdle rates, can add a significant cost component. Figure 2 in the Draft Policy presented PCM results with wide ranges of projected economic outcomes.[180]

Figure 3 in the Draft Policy focuses on 2026 WMEG and 2026 supplemental case results, which shows a significant spread between the forecasted benefits for each case plotted in the figure. The observed variation in forecasted benefits is based on the market footprint. Figure 5 in the Draft Policy builds upon the 2026 results by applying declining hurdle rates to Alt Split 4A and Main Split footprints. These declining hurdle rates represent levels of improved market to market seams coordination (reducing the "friction" between markets) and reduced incremental transmission cost assumptions. Bonneville explained that FERC encouraged stakeholders to

[174] *Id.*
[175] PPC-040725 at 8.
[176] *Id.*
[177] *Id.* at 10.
[178] *Id*. at 8.
[179] *Id*. at 9.
[180] Draft Policy at 27.

coordinate and develop workable solutions to minimize friction at the seams[181] (which the hurdle rate attempts to model) to maximize the benefits of wholesale market transactions for customers.

The assumptions made for hurdle rates in the PCM run by E3 significantly drive the costs and benefits of any given model run. This is because production cost models seek to optimally commit and dispatch resources to meet load for each given hour, while minimizing the production costs required to do so. Hurdle rates are a way to demonstrate that there are costs associated with dispatching a resource in one market footprint to serve load in another market footprint. Therefore, as hurdle rates are reduced, the price separation between market footprints will decrease, as the cost to serve load is levelized across both footprints. Other than the modeling difference to reflect fast-start pricing (Markets+ is modeled to include fast-start pricing and EDAM is modeled without it, and the pricing impacts in the PCM are limited when isolating this factor), the PCM cannot differentiate key market design differences between the two. Thus, hurdle rates are a significant driver of different outcomes between footprints.

The table below shows the hurdle rates for Markets+ footprint exports modeled by E3:

- **WMEG & Base Case** - $14.50/MWh (DA and RT) including dry studies, dry/stressed studies, new transmission studies, and in BPA in EIM studies
- **M2M** - $10.50/MWh (DA) and $7.50/MWh (RT)
- **M2M2** - $7.50/MWh (DA and RT)
- **M2M3** - $5.25/MWh (DA and RT)

Table 3 | Hurdle Rate Descriptions & Value for M2M Cases

Hurdle Rates - Markets+ Footprint Exports						
WMEG	Supplemental Analysis					
	M2M		M2M2		M2M3	
Weighted Average OATT Rate of Market + Friction + Congestion Risk	DA	Weighted Average OATT +$6 adder	DA	Weighted Average OATT + $3 adder	DA	50% of Weighted Average OATT + $3 adder
	M2M DA = $10.50/MWh		M2M2 DA = $7.50/MWh		M2M3 DA = $5.25/MWh	
	RT	Weighted Average OATT + $3 adder	RT	Weighted Average OATT + $3 adder	RT	50% of Weighted Average OATT + $3 adder
$14.50 /MWh in DA & RT	M2M RT = $7.50/MWh		M2M2 RT = $7.50/MWh		M2M3 DA = $5.25/MWh	

**** Adder encompasses value for Friction & Congestion Risk***

[181] In Appendix D, Bonneville described and examined how seams exist today and will in the future, produce operational and commercial friction and inefficiencies that must be carefully managed. With the introduction of multiple day-ahead markets with their own footprints, designs, protocols, and procedures, avoiding negative operational and commercial externalities will be critical. Bonneville emphasized that the region will need to work collaboratively to address the introduction of multiple new day-ahead market seams.

As demonstrated in Figure 5 in the Draft Policy, as the hurdle rates are lowered, the spread between benefits in the different footprints narrows. Therefore, it is critical to examine how realistic these hurdle rate assumptions are when interpreting PCM results. To minimize the production cost in finding the optimal dispatch solution, the PCM has to include the hurdle rate when determining which resources should be awarded to meet load.

Where PCMs fall short is that they assume the costs associated with transacting across two markets are incremental to every transaction and every MW. In reality, transmission customers will hold long-term transmission rights across systems, making those rights sunk costs that the hurdle rate assumes represents an incremental (increased) cost. This modeling assumption is problematic because transmission customers will likely continue to hold these rights as they are valuable for transacting at various source (generating resource) to sink (load service) points across the west.

Indeed, upwards of 90% of the scheduled transmission rights across major western Transmission Service Provider (TSP) systems are made up of long-term transmission that an entity would not consider an incremental cost when considering if a trade is economic or not. For transactions leaving the EDAM footprint, E3 explained that the weighted-average assumed OATT rate component of the hurdle is $9/MWh and for transactions leaving the Markets+ footprint, the weighted-average assumed OATT rate component of the hurdle is $5/MWh.[182] These are assumed costs that many entities would strategically not consider when determining whether to submit a resource offer to a neighboring footprint—as the costs associated with the vast majority of their transmission portfolio are not recoverable—therefore transacting or not does not present incremental transmission costs. Whether the transmission rights are exercised or not, they provide no incremental financial value to the holder.[183] Therefore, as highlighted by PPC, the assumptions regarding the OATT-based component of the hurdle rates are likely highly overstated, particularly given that both markets and other non-market programs, such as the Western Resource Adequacy Program (WRAP), incentivize entities to continue to hold long-term firm transmission rights.

In addition to the hurdle rate component derived from OATT rights is the portion that is defined as market friction. There are many reasons for entities to attempt to reduce friction between markets. One is that many entities who have expressed interest in the day-ahead markets have high levels of bilateral trading with one another—and, thus, those entities benefit from limited friction between markets for future transactions. Price separation between the north and the south in the West is often directionally predictable each hour, due to the differences in resources, loads,

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[182] Energy+Environmental Economics, Western Markets Exploratory Group: Western Day Ahead Market Production Cost Impact Study at 34-35 (June 2023), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/9-public-talking-points-june-2023.zip.

[183] A caveat is that transmission rights holders may resell transmission in some circumstances, which is also not modeled in PCM.

and gas prices that are largely known in the day-ahead timeframe. This predictability favors the likelihood that traders will see lower friction in transacting between EDAM and Markets+. Market friction will also reduce as market operators collaborate to create seams agreements that incentivize efficient trading across the footprint.

With respect to potential results if the 2NV footprint had lower hurdle rates applied, Bonneville agrees that, if hurdle rates were eliminated, the results would be nearly identical to the results of the Single West-Wide Market case. However, the convergence to this result is not necessarily linear. Lower hurdle rates cause prices to converge between the two markets. In the cases in which Bonneville is modeled in Markets+, Bonneville sees higher benefits when hurdles are reduced because Bonneville receives a higher price for its surplus energy. Conversely, if hurdle rates are lowered in cases in which Bonneville is modeled in EDAM, Bonneville would likely receive lower prices for its surplus energy. It is unclear at what reduced hurdle rate level the benefits trending toward single West-wide market would overtake the lesser revenue. For these reasons, Bonneville views the PCM results with varying hurdle rates as informative data points regarding the PCM results as a whole.

Decision

For the reasons explained above, the base hurdle rate assumed in all cases, except the "M2M" sensitivities discussed above, likely overstate the incremental costs to transact between markets. This creates PCM results that reflect artificially high separations in results between market footprints—when in practice, the combination of existing OATT rights held and incentives are expected to reduce market friction thereby reducing the incremental costs for transacting between market footprints. By considering a range of potential hurdle rates, Bonneville appropriately considered hurdle rates in its analysis and assessment, recognizing hurdle rates as an important variable that can significantly impact analytic outcomes. Bonneville reiterates and emphasizes its conclusion in section 5.1.1.4 of the Policy that lower hurdle rates are more likely than those initially modeled in the WMEG studies, providing better information to support its conclusion that Markets+ participation will result in benefits above business-as-usual.

ISSUE 4: Whether Bonneville adequately considered retail rate affordability

Draft Policy Position

Bonneville generally discussed the financial impacts of participation in Markets+ in Section 5.1.2 of the Draft Policy and discussed the sound business rationale evaluation criterion in Section 4.1.4 of the Draft Policy.

Public Comments

Many individuals commented with general concerns over the potential impact to retail electricity rates if Bonneville joins Markets+.[184] PacifiCorp and PGE similarly express concern about whether Markets + "will be more economically beneficial to its retail customers than joining EDAM or staying in WEIM."[185] The Clean Energy Buyers Association (CEBA) suggests that Bonneville's decision "should be heavily based on achieving the maximum benefit to end-use customers."[186] The BlueGreen Alliance specifically highlights the impact to large energy users, such as industrial and commercial ratepayers, and suggests that Bonneville should provide additional analysis on the rate impact for current and prospective single large-load facilities.[187]

Evaluation

While Bonneville markets power and transmission at wholesale rates, it certainly appreciates commenters' concerns about consumers' electricity retail rates. "This cost-based model allows [Bonneville] to offer affordable power and transmission services that drive the region's economy."[188] Bonneville understands that its wholesale rates are incorporated into customers' retail rates. Bonneville provides a thorough discussion of a range of outcomes resulting from day-ahead market participation in Section 5.1 of the Policy. Bonneville evaluated its day-ahead market policy through the lens of *Business*, and determined participation in Markets+ to be supported by a sound business rationale, especially considering the changing utility landscape towards participation in day-ahead markets.[189] Bonneville will continue to establish rates pursuant to section 7(i) of the Northwest Power Act.[190] Issue #54 further discusses Bonneville's obligation to set rates at the lowest possible costs consistent with sound business principles.

Decision

As discussed in Section 5.1.1 through 5.2.5 of the Policy, Bonneville expects participation in Markets+ to result in financial benefits and therefore maintain low rates for Bonneville customers.

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184 BlueGreen Alliance-040725; Brewer-040725; Columbia Snake River Campaign (CSRC) members; CEBA-040425; CRITFC-040725; Modern-040425; OR-WA Governors-040725; PAC_PGE-040725; SCL-040725.
185 PAC-PGE-040725 at 1.
186 CEBA-040425.
187 BlueGreen Alliance-040725 at 2. The BlueGreen Alliance further suggests Bonneville's day-ahead markets decision will result in fewer resources for Bonneville to expand or upgrade transmission resources, which translates to fewer jobs in the region. *Id.* at 3.
188 Bonneville Power Admin., About & Careers, https://www.bpa.gov/about.
189 *See* Policy § 4.1.4.
190 16 U.S.C. § 839e(i).

ISSUE 5: Whether participation would increase transmission rates

Draft Policy Position

Bonneville discussed the design features that limit financial impacts to transmission in Section 5.1.1.8 of the Draft Policy and potential impacts to transmission customers in Section 6.8.

In the Draft Policy, Bonneville acknowledged that "[b]ecause Bonneville's transmission will be used in day-ahead, real time, and bilateral markets, Bonneville recognizes concerns about potential transmission cost shifts between these different markets."[191] While day-ahead market participation may potentially reduce transmission revenues, both EDAM and Markets+ have mechanisms to "help participating TSPs mitigate this impact." In addition, Bonneville would "continue to monitor actual transmission revenue recovery and, if needed, advocate through the market stakeholder process for additional market design adjustments to mitigate any potential loss of transmission revenues."[192]

Public Comments

Tacoma comments that Bonneville has "identified mechanisms to mitigate potential transmission revenue impacts and performed due diligence on market participation fees to appropriately conclude that higher implementation costs for Markets+ will quickly be eclipsed by higher ongoing participation costs for EDAM."[193] PPC and NRU also comment that Bonneville's analysis shows that participating in EDAM will also result in higher ongoing costs.[194]

Powerex comments that "Markets+ encourages transmission customers to retain and purchase long-term firm transmission rights as a result [of] its congestion rent design, use of Type 1A contract-based attribution of clean supply, and WRAP firm transmission requirements." In addition, Powerex states that the "EDAM design does not provide these same incentives . . . potentially putting a significant source of revenue at risk for Bonneville and putting upward pressure on long-term rates."[195]

While supportive of Bonneville's Policy decision, WPAG comments that Bonneville should develop a "day-ahead market monitoring plan, including congestion rent, BPA power and transmission rates, and GHG monitoring sub-plans, so that BPA and customers can monitor and evaluate the actual financial impacts around rates and products arising from BPA joining a day-

[191] Draft Policy at 36.
[192] *Id.*
[193] Tacoma-040225 at 2.
[194] PPC-040725 at 13-14; NRU-040725 at 3.
[195] Powerex-040725 at 4.

ahead market[.]"[196] WPAG also comments that Bonneville needs to address "potential congestion rent, revenue, rate, and other implications" of joining Markets+ prior to participation.[197]

NIPPC comments that its "primary interest . . . continues to be the impact to transmission customers."[198] NIPPC continues that Bonneville should "weigh how it will share the market benefits that accrue to transmission customers (through reduced reserves and imbalance charges) with all its transmission customers."[199] NIPPC also comments that Bonneville "may see more volatility in transmission revenues" and "must consider the implications of more volatile transmission revenue forecasts as it prepares to revisit its financial policies."[200] According to NIPPC, Bonneville "should assign the costs of market implementation to customers in proportion to the benefits they receive" and "the bulk of implementation costs should be borne by BPA's power customers as the primary beneficiaries of a broader market."[201]

PacifiCorp and PGE "request that BPA provide the rationale and associated analysis for how its point-to-point and network integrated transmission service transmission customers benefit" and how implementation costs will be allocated based on that benefit.[202]

Evaluation

Many commenters express concern with increased pressure on transmission rates based on Bonneville's decision to join Markets+. As stated in the Policy, "Bonneville is unable to forecast the financial impact around rates, products, and the volatility for any option prior to issuing its day-ahead market Policy. This is because the specifics needed to conduct financial analysis, such as final market design, footprint, seams agreements, etc. are not yet known. Inventory and market price risk represent key drivers of overall financial risk to Bonneville, which exist in both bilateral and organized markets."[203]

As Tacoma and Powerex point out, Markets+ has features designed to mitigate potential lost transmission revenue. Unlike EDAM, Markets+ "encourages transmission customers to retain and purchase long-term firm transmission rights through its congestion rent design that includes an allocation to transmission rights holders."[204] This direct allocation of congestion rents

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[196] WPAG-040725 at 4.
[197] *Id.*
[198] NIPPC-040725 at 13.
[199] *Id.*
[200] *Id.* at 12.
[201] *Id.*
[202] PAC_PGE-040725 at 4-5.
[203] Policy at 34.
[204] *Id.* at 36.

incentivizes transmission customers to hold onto and purchase long-term transmission rights, mitigating any revenue impacts to long-term service.

In addition, and similar to EDAM, Markets+ includes a transmission revenue recovery mechanism allowing Bonneville to recover losses resulting from releasing unsold available transfer capability (ATC) to the market.[205] This design mitigates any revenue impacts to short-term service.

Regarding the costs of joining Markets+, Bonneville recognizes, as acknowledged by Tacoma, PPC, and NRU, that the higher implementation costs of joining Markets+ are offset by the lower ongoing participation costs. Bonneville will hold workshops prior to the start of the rate proceeding to share proposals regarding cost recovery and cost allocation for Markets+. Whether through a separate "day-ahead market monitoring plan" as WPAG suggests, or through its normal processes, Bonneville will ensure customer engagement regarding the power and transmission rate impacts from joining Markets+ and will provide all supporting "rationale and associated analysis" as requested by PacifiCorp and PGE.

Decision

Bonneville's cost allocation and recovery proposals will be addressed in future workshops and section 7(i) rate proceedings. Bonneville's assessment is that Markets+ design features would likely mitigate potential transmission revenue loss.

5.1.2. Participation and Implementation Cost Estimates

ISSUE 6: Whether implementation costs of Markets+ are justified

Draft Policy Proposal

Bonneville discussed participation and implementation cost estimates in Section 5.1.2. of the Draft Policy.

Public Comments

In Section 5.1.2, Bonneville discussed participation and implementation cost estimates for participation in EDAM and Markets+. Bonneville received comments supporting the direction to join Markets+ despite higher implementation costs based on expected benefits over time. PPC asserts that the "magnitude of potential benefits" justifies the higher implementation costs of

[205] *Id.* at 37.

Markets.[206] Tacoma asserts that Bonneville "has performed due diligence on market participation fees to appropriately conclude that higher implementation costs for Markets+ will quickly be eclipsed by higher ongoing participation costs for EDAM."[207]

Powerex comments that long-benefits are greater than implementation costs. Powerex describes how it is "important to consider the magnitude of . . . value shifts [based on market design] relative to any differences in implementation costs and/or the simplified production cost modeling results."[208]

Other commenters raise concerns about the implementation costs of Markets+. CTUIR reasons that "the EDAM/WEIM market is less expensive to build than Markets+" based on the cost estimates in the Draft Policy.[209] Earthjustice observes that "implementation costs of Market+ are higher than those for EDAM." Commenters also note that costs for Bonneville to join EDAM are less than those to join Markets+ because of the costs previously incurred to develop and join the WEIM.[210] NIPPC further notes that the current Markets+ Phase 2 funding agreement Bonneville may not include the full extent of Bonneville's share of Markets+ implementation costs.[211]

Evaluation

Bonneville has assessed implementation costs of Markets+ and EDAM as relevant to an overall determination regarding the value proposition of each market. Bonneville has identified Markets+ as the better option for the agency and its customers. Pivotal market design elements like congestion revenue can result in value shifts of hundreds of millions of dollars.[212] Bonneville agrees with Powerex and PPC that implementation costs must be considered through the lens of long-term strategic and financial impacts and not in isolation.

While CTUIR and Earthjustice observe that there are higher implementation costs associated with Markets+, referencing only the higher implementation costs is an oversimplification that fails to consider lower ongoing participation fees and anticipated market benefits based on the PCM analysis and market design features.[213] Indeed, Bonneville thoroughly considered the operational complexities, implementation challenges, and potential for sunk costs presented by each market option.[214] The results of this analysis have been weighed against each of Bonneville's day-ahead market participation principles discussed in Section 4 of the Policy.

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206 PPC-040725 at 13-14.
207 Tacoma-0402225 at 2.
208 Powerex-040725 at 5.
209 CTUIR-040725 at 11.
210 Earthjustice-040725 at 24; NIPPC-040725 at 10; *see also* Sierra Club-040725 at 2.
211 NIPPC-040725 at 10.
212 *See* Powerex-040725 at 5.
213 Policy § 5.1.2 (Participation and Implementation Cost Estimates).
214 Policy § 9 (Conclusion and Next Steps).

Decision

The higher upfront Markets+ implementation fees are justified by the anticipated market benefits and lower ongoing participation fees. Bonneville updated Policy Section 5.1.2.2. accordingly.

ISSUE 7: Whether Bonneville should further refine cost analyses before making a day-ahead market decision

Draft Policy Proposal

Bonneville discussed participation and implementation cost estimates in Section 5.1.2. of the Draft Policy.

Public Comments

Several commenters raise questions or concerns regarding the estimates of implementation and ongoing participation fees. RNW asks whether Bonneville has considered the additional staff time, hardware and software costs, and further public process to implement joining Markets+ and leaving the WEIM in its financial calculations.[215] SCL asks whether the implementation cost and ongoing participation fee estimates provided by SPP have been updated since 2022.[216]

NIPPC and Puget Sound Energy (PSE) provide thoughts on the on-going participation costs estimated by each of the Market Operators. NIPPC suggests that "[w]hile SPP's estimate of those fees is roughly half of EDAM's, NIPPC cautions that this is based on SPP's estimate of BPA's share of the Markets+ annual operating expenses and may be largely speculative considering that SPP has only just begun its Phase 2 market development process. As the market design continues to evolve and SPP begins implementing Phase 2, the estimated annual costs may increase. Because EDAM is based on an already functioning market platform, the risks of unanticipated costs is much lower for EDAM than Markets+."[217] PSE provides a different view, suggesting that "neither CAISO or Pathways have publicly contemplated firm costs for the new regional organization or how the collective grid management and regional organization charges will be cost allocated between EDAM entities and CAISO participants. This leaves open a broad range of outcomes in EDAM for ongoing costs of market participation."[218]

Evaluation

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215 RNW-040725 at 22; *see also* PAC_PGC-040725 at 4-5 (asserting Bonneville has not made clear the details of its implementation costs).
216 SCL-040725, App. A at 2.
217 NIPPC-070425 at 10-11.
218 Puget-040125 at 1.

Bonneville discusses internal implementation costs in Table 8 of Section 5.1.2.3 of the Policy. The non-labor component reflects initial costs for software and hardware upgrades needed for supporting day-ahead market implementation, while the labor component reflects the incremental staffing costs/time. Bonneville acknowledges that these figures are estimated based upon the best available data.

Bonneville has used its best estimates for fees and cost allocations based upon the most current data available at each juncture. In the case of Bonneville's Day-Ahead Market Policy, estimates were based on information provided by each market operator in early 2025. Uncertainty is inherent in both markets. As NIPPC noted, Markets+ is a new platform. As PSE noted, the cost to implement and maintain a Regional Organization (RO) has not been fully explored or accounted for in the estimates provided by EDAM. Bonneville acknowledges that uncertainty surrounds the discussion of participation fees and implementation costs; indeed, Bonneville uses the words "forecast" and "estimates" in its Policy to reflect this uncertainty.

Decision

Bonneville is not persuaded to further refine cost estimates prior to publishing the Policy. However, Bonneville updated the Section 5.2.1.2 of the Policy to specify that it assessed implementation and participation costs from CAISO, SPP, and internal projections based upon the best-available estimates in early 2025.

ISSUE 8: Whether Bonneville should address the Phase 2 Funding Agreement in its DAM policy decision

Draft Policy Position

This issue was not addressed in the Draft Policy.

Public Comments

OCGC expresses concern that Bonneville "appears to have moved forward with a significant funding decision without a transparent stakeholder process and without assurances of accountability."[219] OCGC comments that Bonneville did not advise stakeholders of Bonneville's full liability under the Phase 2 Funding Agreement, that Bonneville submitted a "letter of assurances" to SPP, and that Bonneville did not explain how costs of market development or participation would be recovered.[220] OCGC requests Bonneville to explain how it has fulfilled its

[219] OCGC-040725 at 6.
[220] *Id.*

vision of "accountability to the region" and how Bonneville's decision to fund Phase 2 of Markets+ has a "sound business rationale."[221]

RNW requests that Bonneville explain the lack of public process around the decision to fund Phase 2 of Markets+ and whether the Phase 2 Funding Agreement obligates Bonneville to join Markets+.[222]

Earthjustice also refers to Bonneville's decision to fund Phase 2 of Markets+, but in the context of a National Environmental Policy Act-related (NEPA) argument.[223]

Conversely, Columbia Power Cooperative (CPC) expressed understanding that the Phase 2 Funding Agreement does not obligate Bonneville to join Markets+, that Bonneville is agreeing to fund development of the market, and that, in doing so, Bonneville preserves optionality.[224]

Evaluation

Whether Bonneville has funded day-ahead market development is unrelated to Bonneville's day-ahead market evaluation criteria and outside the scope of Bonneville's day-ahead market policy decision. Nevertheless, Bonneville must clarify several misconceptions related to the Phase 2 Funding Agreement.

First, the Phase 2 Funding Agreement is not a commitment to joining Markets+, which FERC recognized in its Order: "the Funding Agreement does not obligate any Funding Participant to proceed with Markets+ participation. Rather, the Funding Agreement requires the Funding Participant to meet its financial obligations to avoid shifting those obligations to remaining Funding Participants or SPP."[225] Second, the "letter of assurances" BPA must submit to the lender does not create an additional obligation on Bonneville's part. Bonneville, unlike the other Phase 2 funding participants, is legally prohibited from posting collateral, but is nevertheless obligated to honor its contractual obligations. Therefore, while the lender is requiring other Phase 2 funding participants to post collateral for their proportional shares of Phase 2 development, the lender is accepting simply Bonneville's promise to pay, which is an obligation arising from the Phase 2 Funding Agreement itself. The "letter of assurances" outlines for the

[221] *Id.*
[222] RNW-040725 at 21-22. Seattle City Light also raised stakeholder process concerns around the Phase 2 Funding Agreement. SCL-040725 at 50.
[223] Earthjustice-040725 at 3-5.
[224] CPC-040725 at 1.
[225] *SPP*, 191 FERC ¶ 61,071, at P 34 (Apr. 22, 2025).

lender's underwriting purposes Bonneville's limitations as a federal entity and its statutory obligation to pay.[226]

Here, Bonneville's decision to execute the Phase 2 Funding Agreement was supported by a sound business rationale. As noted above, the decision to fund Phase 2 of Markets+ is not a commitment to join Markets+ and Bonneville negotiated provisions to mitigate liability under the Phase 2 Funding Agreement. Bonneville also received broad support from its customers to fund Phase 2 development. Indeed, Phase 2 development includes a broad coalition of sophisticated utilities in the West. Finally, participating in Phase 2 enables Bonneville to continue participating in market design at a crucial stage and maintains a second viable market option.

RNW raises concerns about the public process for the Phase 2 Funding Agreement. Bonneville's authority to contract is expressly provided in statute.[227] Bonneville is not required to undergo a public process for every contract decision, nor would that be practical for Bonneville to carry out its business interests. Bonneville notes, however, that SPP conducted a stakeholder process with interested parties to develop the Phase 2 Funding Agreement and Bonneville publicly expressed its intent to fund Phase 2 in January 2025.[228]

Decision

Bonneville will not address the SPP Phase 2 Funding Agreement in the Policy.

ISSUE 9: Whether Bonneville should address Pathways funding in its day-ahead market policy decision

Draft Policy Proposal

Bonneville did not address this issue in the Draft Policy.

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[226] *See id.* at P 35 ("We find it sufficient that the Funding Agreement requires Bonneville, a federal agency, to submit a letter of assurances to the lender representing its authority to enter into the Funding Agreement and its statutory obligation to pay the funding obligations.").
[227] Bonneville Project Act, 16 U.S.C. § 832a(f) ("Subject only to the provisions of this chapter, the Administrator is authorized to enter into such contracts, agreements, and arrangements, including the amendment, modification, adjustment, or cancelation thereof and the compromise or final settlement of any claim arising thereunder, and to make such expenditures, upon such terms and conditions and in such manner as he may deem necessary.").
[228] SPP, SPP's Markets+ tariff receives FERC Approval (Jan. 16, 2025), *available at* https://spp.org/news-list/spp-s-marketsplus-tariff-receives-ferc-approval/.

Public Comments

OCGC commented, "[d]espite BPA's heavy emphasis on assessing 'two viable markets' and on independent governance as a decision criteria, BPA had not itself publicly pledged any funds to the effort that was widely expected to enable" Phases 2 and 3 of Pathways, even though a forthcoming funding contribution of $25,000 had been communicated to the Oregon and Washington Senate delegation.[229]

Evaluation

Whether Bonneville has funded day-ahead market development is unrelated to Bonneville's day-ahead market evaluation criteria and outside the scope of Bonneville's day-ahead market policy decision. Notwithstanding the foregoing, and in the interest of transparency, Bonneville offers the following response:

As OCGC noted, Bonneville "had dedicated key senior staff to the Pathways Phase 2 Working Groups."[230] In addition, Bonneville participated in the public meetings of the Pathways Launch Committee and commented at every opportunity. As for funding Pathways, Bonneville sought to fund the effort, but first had to confirm that any financial contribution would be consistent with Pathway's grant award from the U.S. Department of Energy (DOE). While that confirmation was occurring, DOE issued additional guidance for grants by DOE entities, which remains in review.

Decision

Bonneville will not address Pathways funding in the Policy but will continue to monitor and participate in the Pathways initiative as resources allow.

ISSUE 10: Whether Bonneville properly evaluated the potential for an RTO in its decision to pursue Markets+

Draft Policy Proposal

Bonneville discusses the potential for an RTO in Appendix C of the Draft Policy.

Public Comments

Pathways comments that "Appendix C lacks sufficient detail or context about the multitude of issues Bonneville would need to evaluate when considering participation in an RTO, much less

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229 OCGC-040725 at 3.
230 *Id.*

about how Markets+ offers a preferable option over the Pathways recommendations for market services beyond EDAM." [231] Pathways also states that "Appendix C is insufficient to be relied upon as supplemental basis for a day-ahead market participation decision."[232]

Evaluation

As stated in Appendix C to the Policy, Bonneville "is only considering day-ahead market participation in this process." While Appendix C outlined the potential benefits of Markets+ over EDAM if Bonneville decides to join an RTO in the future, Bonneville did not factor in those considerations in its decision to join Markets+.

Decision

If Bonneville decides to explore RTO formation in the future, Bonneville would conduct a separate public process to evaluate that decision.

5.2. Market Design Considerations

5.2.1. Governance

A. High Level Governance Issues

ISSUE 11: Whether Bonneville appropriately weighed the importance of governance

Draft Policy Proposal

Bonneville outlined governance as one of its day-ahead market evaluation principles in Section 4.1.6 of the Draft Policy. In Section 5.2.1, the agency explained that independent market governance continues to be of great importance to its direction towards participation in Markets+.

Public Comments

Many commenters support Bonneville's draft decision based on the superior governance of Markets+.[233] The Joint Authors support Bonneville's use of evaluation principles to ensure "that

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[231] Pathways-040725 at 6.
[232] *Id.*
[233] AWEC-040725; CBEC-033125; Big Bend-040725; CRPUD-040725; Hood River-040425; IFP-040725; Joint Authors-040725; Lincoln-040425; Modern-040425; NRU-040725; Pacific-040725; Powerex-040725; PPC-040725; Snohomish-040725; Tacoma-040225; Umatilla-040425; Wasco-033125; WPUDA-040725.

all critical aspects of a day-ahead market are considered, while ensuring that the evaluation does not inadvertently give undue focus to one aspect over another."[234]

Snohomish "agrees with Bonneville that independent governance is a paramount consideration in order to ensure that all market participants are treated equitably in the development of market rules and in management of market operations."[235] Snohomish states, "CAISO's EDAM and SPP's Markets+ offer substantially different governance structures largely due to the circumstances of each market's origins," with CAISO "created by the California legislature as a market to serve the people of California."[236]

Tacoma states, "Markets+ meets a pragmatic standard for independent governance while EDAM does not and could not for many years into an uncertain future."[237] Tacoma further states, "Markets+ has been built from the ground up with a fully independent Board of Directors and a structure where each participant has a voice and a vote, while EDAM will operate under organizational and statutory mandates specific to California."[238]

Salem Electric and Columbia Basin Electric Cooperative (CBEC) state, "[e]ven if the only reason not to go to the CAISO EDAM was governance, that would be enough."[239]

Idaho Falls Power believes "Markets+ has superior governance" and "urges BPA to continue to show leadership in the development of a market that has proper governance, equitable congestion management and revenue allocation, promotes transmission access and investments and last but certainly not least has proper price formation that is unbiased by state level policies."[240]

WPUDA "finds SPP's Markets+ superior in the area of governance" because its public utility district members involved in Markets+ design report "stakeholders have been and continue to be given due weight and consideration," while, in EDAM design, "participants outside California were disadvantaged" and the "disadvantage . . . continues in present times of outlier events."[241]

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[234] Joint Authors-040725 at 1; *see also* PPC-040725 at 3.
[235] Snohomish-040725 at 2.
[236] *Id.* at 2-3.
[237] Tacoma-040725 at 3.
[238] *Id.*
[239] Salem Electric-040725 at 1; CBEC-040725 at 1.
[240] IFP-040725 at 1.
[241] WPUDA-031225 at 1.

Powerex "strongly supports the foundational importance placed on independent governance in Bonneville's evaluation framework."[242] It asserts, "[t]here is nothing short of full independent governance that can provide Bonneville with confidence in its choice for the long-term."[243]

Several commenters acknowledge that independent governance is an important consideration, but express concern that Bonneville places too much emphasis on governance relative to other factors, such as the market's footprint, transmission connectivity, and economic impact.[244] The State Agencies request Bonneville to weight its evaluation criteria and to "provide a more comprehensive analysis of the risks of governance in both markets." [245] SCL believes that the Pathways Initiative Step 2 proposal satisfies Bonneville's definition of independence.[246]

Evaluation

Bonneville adopted governance as one of its evaluation principles in the Draft Policy. Specifically, Bonneville must ensure "[t]he market has a durable, effective, and independent governance structure which provides fair representation to all market participants and stakeholders. Decision-making and stakeholder engagement occur in a transparent and inclusive manner."[247] As the Policy explains, this evaluation principle is a "consideration[] for Bonneville to weigh in its evaluation."[248] Bonneville's analysis does not treat independent governance as a check box, where some minimum threshold of independence is adequate to render further comparisons or analysis unnecessary. Instead, as an evaluation principle, Bonneville compared the governance structures of the two markets and considered commenter perspectives. Bonneville has explained its concerns with EDAM governance, and why it believes Markets+ governance is superior.

Independent governance does not factor into a strict formula where the risk of negative governance-related outcomes is quantified or weighted against other criteria. There is unmeasurable uncertainty regarding what issues will confront day-ahead markets in the future. In addition to past disputes and known current challenges, there will surely be issues that arise that

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[242] Powerex-040725 at 1.
[243] *Id.*
[244] EWEB-040725 at 1 ("We also acknowledge that independent governance is an important consideration for BPA when deciding which day-ahead market to join. However, we believe that independent governance should not be the sole factor in this decision; it must be carefully weighed alongside the critical elements of transmission connectivity and market footprint."); *see also* OR-WA State Agencies-040725 at 9; PAC_PGE-040725 at 3-4; SCL-040725 at 16, 29, 46, 52, App. A at 1; Public Comments Group 2 at 1; Public Comments-Sierra Club; South-030225.
[245] OR-WA Agencies-040725 at 2, 9.
[246] SCL-040725 at 13.
[247] Draft Policy at 11; *see also id.* at 13 ("At the highest level, the decision-making body for the market must be free of disproportionate obligation to the policies of a single state, entity, or customer class to ensure that market design is on an equal footing for all participants, including Bonneville.").
[248] Policy at 11.

no one has yet fully contemplated, and governance will surely impact market decisions that impact financial outcomes. Bonneville's reassurance in joining a day-ahead market is that there is a process available to work through those challenges. Bonneville would be accepting great risk if the process is biased towards certain entities, does not allow issues of concern to be prioritized, or is not durable enough to provide fair representation in crisis situations.

Bonneville recognizes that the weight placed on governance is necessarily qualitative, and reasonable minds may differ on the appropriate weight to place on governance. Bonneville notes that many comments agree with Bonneville's policy decision considering the superior governance of Markets+.[249] Bonneville observes that the Markets+ governance has already resulted in superior policies related to price formation and fast-start pricing.[250] Bonneville sees Markets+ governance as more truly independent with greater opportunities for stakeholder-driven engagement and decision making on market rules.

Decision

Bonneville has holistically approached its analysis of governance in the Policy. Bonneville made an informed and reasonable comparison of Markets+ and EDAM and has given appropriate weight to their relative governance models in reaching its day-ahead market policy decision.

ISSUE 12: Whether Bonneville's acceptance of WEIM governance is consistent with its DAM policy direction

Draft Policy Proposal

Bonneville did not address this issue in the Draft Policy.

Public Comments

RNW comments: "Please explain why the WEIM governance, which BPA deemed adequate in 2019, is now considered inadequate. Additionally, why did BPA feel comfortable joining the EIM and committing to collaborative improvements, yet now—despite having ample opportunity

[249] *See* AWEC-040725; CBEC-033125; Big Bend-040725; CRPUD-040725; Hood River-040425; IFP-040725; Joint Authors-040725; Lincoln-040425; Modern-040425; NRU-040725; Pacific-040725; Powerex-040725; PPC-040725; Snohomish-040725; Tacoma-040225; Umatilla-040425; Wasco-033125; WPUDA-040725; *see also* Letter from Puget Sound Energy *et al.* to Governor Bob Ferguson at 2 (Apr. 15, 2025), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/20250417-letter-from-washington-utilities-to-governor-ferguson.pdf ("It is impossible to have confidence in a market operator with legal obligations to the state with the world's fifth largest economy. That imbalance of market power puts the value of the Pacific Northwest hydropower fleet at risk against the interests of the merchant generators and other California interests.").
[250] *See* Section 5.1.5 below.

to influence the current governance proposal through the Pathways Initiative and with a pending decision by the California Legislature to address BPA's concerns—the agency believes the only viable option is to move forward with a decision to join a different market at this time?"[251]

Evaluation

In the EIM ROD, Bonneville stated, "[t]he current EIM governance structure is not a barrier to Bonneville joining the EIM, but Bonneville will continue to seek improvements in collaboration with its customers."[252] Bonneville notes that, in citing this language, RNW acknowledges Bonneville's longstanding concerns with CAISO governance.[253] Discussion in the EIM ROD focused on the role of the Governance Review Committee and the potential opportunities for governance improvements as a result of the Governance Review Committee's work. Since that time, work has continued on the CAISO governance. However, after over a decade of ongoing collaboration and over three years since joining the WEIM, the current governance and the Pathways proposal still fall short of meeting Bonneville's principle for independent governance, while Markets+ meets that principle.

At the time it joined the WEIM, Bonneville indicated it was Bonneville's intent to continue to monitor the market and WEIM development to ensure its interests would continue to be protected. As WEIM is a voluntary market, Bonneville would have the right to withdraw from the EIM for any reason.[254]

Joining a day-ahead market is likely to have a much larger impact on Bonneville's business than joining an energy imbalance market. The volume of energy marketed through the day-ahead market is significantly larger than that bid into the real-time EIM. With increased scale comes increased risk. Snohomish explained its support for Markets+ in similar terms: "Given the magnitude of trade likely to occur within day-ahead markets, and the potential influence of market rules and market operations over the allocation of costs and benefits of market participation, Snohomish has a strong preference for the fully independent governance structure of Markets+."[255]

Decision

Bonneville expressed concern regarding WEIM governance in the EIM ROD. A day-ahead market increases the potential ramifications of WEIM governance. Therefore, Bonneville's

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[251] RNW-040725 at 10-11.
[252] Bonneville Power Admin., Administrator's Record of Decision, Energy Imbalance Market Policy at 92 (Sept. 2019), *available at* https://www.bpa.gov/-/media/Aep/projects/energy-imbalance-market/rod-20190926-energy-imbalance-market-policy.pdf ("EIM Policy ROD").
[253] RNW-040725 at 11.
[254] EIM Policy ROD at 35-36.
[255] Snohomish-040725 at 3.

decision to participate in the WEIM is not inconsistent with its governance evaluation in the day-ahead market policy.

ISSUE 13: Whether Bonneville should delay its decision

Draft Policy Proposal

Section 5.2.1.1 and Appendix B of the Draft Policy discussed the impact of the Pathways Initiative. In Section 8 of the Draft Policy, Bonneville noted requests to delay but concluded that its participation in Markets+ is the best long-term strategic direction.

Public Comments

Despite the potential Pathways updates and California legislation, many commenters do not support delaying Bonneville's decision. For example, AWEC "does not believe that it is necessary or appropriate for BPA to delay its decision to see what ultimately unfolds with EDAM governance changes."[256] Tacoma contends, "It would not be responsible for BPA to delay its day-ahead market decision based on insufficient and uncertain efforts to increase the independence of EDAM governance."[257] Commenters cite a number of reasons in support of the timing of Bonneville's policy decision: commenters strongly support the design features of Markets+;[258] the decision is necessary to move forward with Provider of Choice long-term power sales contracts;[259] proceeding now allows Bonneville to fully participate in Phase 2 development;[260] the Pathways Initiative proposal, if enacted, only offers partial independence;[261] the decision preserves Bonneville's critical role in the Western Interconnection;[262] it is unreasonable to ask BPA to wait for EDAM governance reforms when other entities in the region are making decisions;[263] and it is important to keep two market options available.[264]

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[256] AWEC-040725 at 1.
[257] Tacoma-040225 at 7.
[258] Big Bend-040725 at 1; Cowlitz-040725 at 1; CBEC-033125 at 1; CPC-040725 at 1; CRPUD-040725 at 1; Franklin PUD-040225; Hood River-040425 at 2; IFP-040725 at 1-2; Joint Authors-040725 at 1-2; Lincoln-040425 at 1; Mason-040725 at 1-2; Modern-040425 at 1; Pacific-040725 at 1; Powerex-040725 at 1-2; Umatilla-040425 at 1-2; WPUDA-033125 at 1-4.
[259] AWEC-040725 at 2-3.
[260] *Id.*
[261] Big Bend-040725 at 1; CEBA-040425 at 2; Cowlitz-040725 at 1; CRPUD-040725 at 1; Hood River-040425 at 2; Joint Authors-040725 at 2; Lincoln-040425 at 1; Mason-040725 at 1-2; Modern-040425 at 1; Pacific-040725 at 1; Powerex-040725 at 1-2; PPC-040725 at 2, 7, 15; Puget-040425 at 2; Snohomish-040725 at 3; Tacoma-040725 at 3-4; WPAG-040725 at 1.
[262] Hood River-040425 at 2; Lincoln-040425 at 1; Mason-040725 at 1-2; Modern-040425 at 1; Pacific-040725 at 1; Powerex-040725 at 1-2.
[263] PPC-040725 at 15.
[264] Puget-040425 at 2.

Conversely, a number of commenters suggest that Bonneville should delay its decision on a day-ahead market policy until the outcome of the Pathways Initiative proposal and California legislation is known.[265] Amazon Web Services comments that "until legislation is fully adopted, the independent nature of EDAM is in question" and that Bonneville should wait until the "outcome is known and can be fully measured and understood."[266] NIPPC disagrees with Bonneville's contention that Pathways as proposed will be insufficiently independent.[267] NWEC suggests that Bonneville should extend its timeline by nine months to see the results of the Pathways Initiative. It notes that, since Bonneville is not joining until 2028, there is time to await Pathways resolution.[268]

In addition, the State Agencies urge a discussion of whether delay would allow design features and rate impacts to be better understood.[269] Pacific Gas & Electric states that delay places additional pressure "on CAISO and California to reform."[270] RNW and SCL comment that, because Bonneville has already committed to funding Phase 2 of Markets+, Bonneville does not gain anything by moving forward at this time.[271] The Oregon and Washington Senators suggest the stakeholder process could be strengthened if Bonneville extended its comment period and decision making process.[272]

OCGC comments that the decision should be delayed due to the risk that federal workforce reductions pose to "BPA's ability to fulfill one of its core obligations—to deliver power to the region safely and reliably."[273] RNW also suggests delay until reductions in the federal workforce and implications for day-ahead markets can be fully understood.[274]

Evaluation

Bonneville does not find merit in waiting for EDAM to incrementally improve its governance. First, Bonneville has determined that the existing Markets+ governance is superior even to the Pathways Step 2 governance revisions currently proposed for EDAM, which still require legislative approval. Second, the Pathways Step 2 governance does not sufficiently address

[265] AWS-040725 at 2; BlueGreen Alliance-040725 at 3; CTUIR-040725 at 15; Dotson-040725 at 3; EWEB-040725 at 1; CSRC; NIPPC-040725 at 7; NWEC-040725 at 1-3; OCGC-040725 at 2, 7; PAC_PGE-040725 at 4; Pathways-040725 at 6; Public Comments Group 2; Public Comments Sierra Club; SCE-040725 at 1-2; SCL-040725 at 13; Sierra Club-040725 at 3; South-030225; Yakama-040325 at 13.
[266]AWS-040725 at 2.
[267] NIPPC-040725 at 2.
[268] NWEC-040725 at 2
[269] OR-WA State Agencies-040725 at 1-2; *see also* Benedict-033125 at 1; CEBA-040725 at 1; Earthjustice-040725 at 25; PAC_PGE-040725 at 6-7; RNW-040725 at 8; SCL-040725 at 1, 13.
[270] PG&E-040725 at 1-2.
[271] RNW-040725 at 21; SCL-040725 at 4.
[272] OR-WA Senators-040825 at 1.
[273] OCGC-040725 at 2.
[274] RNW-040725 at 8.

Bonneville's concerns regarding independence and EDAM governance independence would continue to be insufficient, even under Pathways Step 2.

Furthermore, there is strategic benefit to making a policy decision now. Bonneville agrees with commenters that making a policy decision on its proposed timeline will allow better coordination with other Bonneville efforts, will provide an "early seat at the table" for participation in Markets+, and will maintain a market development speed that matches other entities. In addition, it is necessary for Bonneville to provide clear expectations to customers, sovereigns, and stakeholders now to mitigate uncertainty and to collaborate on next steps for implementation, including rates and tariff proceedings.

There is no guarantee that the California state legislative processes will produce better options for governance in comparison to Markets+, nor would it be appropriate for Bonneville, a federal entity, to delay its business opportunities to advance its statutory mission based on ongoing state legislative processes. Bonneville discusses the Pathways Step 2 proposal in Appendix B of the Draft Policy, and further in Issue #16 below. The Pathways Launch Committee considered a spectrum of incrementally independent governance options and ultimately proposed Option 2 in its Step 2 Final Proposal, with a potential for implementing Option 2.5. Under Option 2, an RO would be formed to allow expansion and greater independence. However, market operations and administration would remain under the California-appointed CAISO Board of Governors through a contract. This presents potential conflicts of interest because CAISO also operates the largest BAA within the EDAM footprint. Sections of the CAISO tariff pertaining to regional markets (i.e., WEIM and EDAM) would remain within the CAISO's integrated tariff, but would be placed under the RO Board's authority. All contracts and liabilities would remain with CAISO rather than transferring to the RO.

California legislation is necessary to effectuate the changes suggested in Pathways Step 2 as discussed in the previous paragraph. SB 540, as introduced, would add, among other provisions, section 345.6 to the California Public Utilities Code. Section 345.6 would allow CAISO and utilities whose systems are currently operated by CAISO to participate in an energy market governed by an independent RO.[275] Bonneville observes that the proposed legislation, including potential amendments discussed in committee, continue to center California interests.

In the proposed legislation, there is a continued requirement that CAISO "shall conduct its operations . . . consistent with the interests of the people of the state."[276] It would require the RO market to be operated by CAISO, and CAISO would also be the largest BAA in the RO footprint. If California elected to withdraw from the market, there would be no alternative vendor

[275] S.B. 540, 2025-2026 Leg., Reg. Sess. § 345.6(a) (Cal. 2025) (as amended May 1, 2025) ("SB 540").
[276] California Public Utilities Code § 345.5(a).

to operate the market. Bonneville sees this as an effective "veto" for California interests, especially in light of the proposed ability of the California Public Utilities Commission (CPUC) to order California utilities to withdraw from the market for a list of reasons, including detriment to California policies.[277]

Bonneville also notes that, in discussions of the California Senate Energy, Utilities, and Communications Committees on April 21, 2025, Committee members and the bill author focused on adding additional safeguards to ensure the market supports California's policies and interests. While Bonneville determined Markets+ governance is preferable to EDAM even with SB 540 as introduced, the trend appears to be towards less independence. Additionally, Committee discussions introduce additional uncertainty about future legislation.

NIPPC disagrees with Bonneville's characterization of Step 2 independence in the Draft Policy, and "suggests that BPA's conclusions . . . may be missing the forest for the trees."[278] NIPPC argues that Pathways is intended to be an incremental, transitional step.[279] Similarly, SCL argues the Pathways Proposal "is a huge milestone in the stepwise approach [and] is the beginning of what will assuredly be further augmentation in the governance of western markets[.]"[280] These arguments appear to acknowledge that there are further levels of independence that EDAM should aspire towards through additional incremental steps. However, NIPPC believes that the Pathways Option 4.0 (a fully independent market with separate operations from the CAISO) is "too extreme."[281] In contrast, Markets+ has already achieved a level of independence comparable to Pathways Option 4.0, including a separate tariff and dedicated staff.

Bonneville recognizes the stakeholder processes that CAISO is currently undertaking to reform or address congestion revenue allocation, greenhouse gas accounting for other state requirements, and price formation enhancements. Bonneville supports CAISO's efforts to improve market design features for the benefit of stakeholders and the region and will continue to participate in those efforts. In light of the governance concerns and market design preferences Bonneville has highlighted in the Policy and ROD, Bonneville does not find the ongoing stakeholder processes to be a compelling reason to pause its decision on a day-ahead market policy.

Further, it is not clear what will continue to inspire future incremental independent governance of EDAM. NIPPC recognizes that competition between EDAM and Markets+ has incentivized the CAISO and California stakeholders to more seriously consider independent governance. Bonneville acknowledges that the existence of Markets+ has contributed to more independent

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[277] SB 540 § 345.6(d)(2).
[278] NIPPC-040725 at 7-8.
[279] *Id.*
[280] SCL-040725 at 13.
[281] NIPPC-040725 at 8.

governance for EDAM. Indeed, in the Governance Review Committee, joint authority over certain tariff provisions was deemed as far as was possible to go toward independent governance. Without this competition, there may be little incentive for California to allow the market to move toward greater independence.

Bonneville does not see maintaining competitive pressure as a compelling reason to delay its decision on a day-ahead market policy. Many entities in the region have already made decisions on day-ahead market participation, and those entities now can shape the market designs. Bonneville has already delayed its day-ahead market process, which allowed Pathways an opportunity to approve its Step 2 proposal and California interests to sponsor legislation. During this period of delay, Bonneville was able to evaluate the scope of independence proposed by Step 2 of the Pathways Initiative and legislation introduced in the California State Senate. Particularly in light of Bonneville's assessment that Pathways and current legislation are unlikely to result in sufficiently independent governance, Bonneville declines to further delay its day-ahead market policy decision.

Considering Markets+, Bonneville has an opportunity to take steps to join a market designed through an independent process and with an independent governance structure to address future issues. If Bonneville were to adopt a direction towards EDAM and wait for future governance improvements, CAISO's control of operations, the intertwined tariff, and CAISO's status as contractual counterparty would remain problematic. The recommendations of Pathways Step 2 and provisions of pending state legislation will maintain CAISO administration of CAISO market operations. The next years of formative market implementation are critical. For at least those years, even if SB 540 were enacted as proposed, almost all policy and legal support staffing will be subject to CAISO administration, with CAISO maintaining liability and contracts for the market.[282] Bonneville opts for independent governance now, rather than potential incremental independence.

Finally, the composition of Bonneville's workforce is out of scope of this policy decision and does not merit delay.

Decision

Bonneville will not delay its decision based on potential CAISO governance improvements. Bonneville included its rationale for declining to delay in Section 2.3 of the Policy.

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[282] *See* Pathways Launch Committee Step 2 Final Proposal at 42 (Nov. 15, 2024), *available at* https://www.westernenergyboard.org/wp-content/uploads/Pathways-Initiative-Step-2-Final-Proposal.pdf ("Pathways Step 2 Final Proposal").

ISSUE 14: Whether Bonneville inaccurately referred to CAISO as a market participant

Draft Policy Proposal

The Draft Policy included references to CAISO as a market participant in EDAM.

Public Comments

Pathways states, "Bonneville's multiple assertions in the Draft Policy that CAISO is a market participant is, in our view, a troubling distortion. As a Launch Committee, we have highlighted stakeholder concerns—including concerns among our committee members—about CAISO's dual roles (mostly defined by the North American Electric Reliability Corporation) within the same footprint as the market it operates (for example, as a balancing authority or a transmission operator). But these concerns are clearly distinguishable from how actual market participants engage in WEIM and will engage in EDAM."[283]

Evaluation

Bonneville agrees with commenters that CAISO is not a market participant. Bonneville corrected any references to CAISO as a market participant in its Policy. The Policy now identifies CAISO as a participating BA in EDAM.

Decision

Bonneville updated its Final Policy to reflect CAISO's role as a BA and not a market participant in EDAM.

B. EDAM and Markets+: Relative Independence

ISSUE 15: Whether Bonneville accurately described and considered the current EDAM governance under Pathways Step 1

Draft Policy Proposal

Section 5.2.1 and Appendix B of the Draft Policy discussed governance and finds that the independence of the Markets+ decision-making body is superior to that of the EDAM.

Public Comments

[283] Pathways-040725 at 3.

CAISO, SCL, and NIPPC argue that Bonneville did not adequately consider the governance changes entailed with the Pathways Step 1.[284] CAISO and Pathways specifically comment on Bonneville's characterization of the CAISO Board of Governors' authority in response to "exigent circumstances."[285]

CAISO summarizes Step 1's current state.[286] CAISO argues that Step 1's primary authority and dual-filing rights address Bonneville's concerns with fair representation.[287] CAISO characterizes the CAISO Board of Governors' unilateral authority under "exigent circumstances" as "a narrowly-drawn provision."[288]

SCL asserts that, under Step 1, the EDAM's Western Energy Market (WEM) Governing Body will have greater independence than SPP's Markets+ Independent Panel (MIP).[289]

NIPPC states, "BPA's Draft Policy contains a surprisingly short-sighted dismissal of the significance of establishing a dual filing 'jump ball' mechanism . . . ."[290] NIPPC asserts that Bonneville's view "simply does not comport with NIPPC's understanding of the Pathways Step 1 reforms nor the experience of market participants—including many NIPPC members—in New England where a 'jump ball' mechanism was first established."[291]

Pathways argues that Bonneville conflated dual filing with unilateral filing.[292] Pathways argues, "The dual filing approach in Step 1 is a material increase in the independence of the WEM [Governing Body] because it requires FERC—rather than the Board of Governors—to ultimately resolve disputes between the WEM [Governing Body] and the Board of Governors."[293] Pathways also states, "Bonneville takes a considerable leap to warn of a hypothetical disconnect on market issues between the WEM [Governing Body] and Board of Governors under Primary Authority."[294]

Evaluation

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[284] CAISO-040725 at 2-4; SCL-040725 at 15, 49-50, 52; NIPPC-040725 at 7.
[285] CAISO-040725 at 3-4; Pathways-040725 at 1-2.
[286] CAISO-040725 at 2 ("This structure has already been approved by the ISO Board and Western Energy Markets (WEM) Governing Body, was accepted by FERC on April 2, 2025, and will go into effect soon, once the triggering requirement for EDAM commitments has been met.").
[287] *Id.* at 3.
[288] *Id.* at 3-4.
[289] SCL-040725 at 15 and 50.
[290] NIPPC-040725 at 7.
[291] *Id.*
[292] Pathways-040725 at 1-2.
[293] *Id.*
[294] *Id.*

The CAISO, SCL, and NIPPC argue that Bonneville did not adequately consider the governance changes entailed with the Pathways Step 1.[295] Pathways argues Bonneville "conflat[es]" the dual-filing under Step 1 with unilateral filing.[296] Bonneville discussed Pathways Step 1 in Appendix B of the Draft Policy. Bonneville acknowledges the governance improvements for CAISO-operated markets that have evolved over recent years, including the work of the Governance Review Committee and most recently the recommendations of Pathways Step 1, specifically the dual-filing provision. Bonneville disagrees that it has conflated the Step 1 procedures; Bonneville's assessment of Step 1 clearly discusses the role the Board of Governors would play in "exigent circumstances."

Bonneville's emphasis on the transition from joint to primary authority was in response to how Step 1 was communicated as "*elevating* the authority of the WEM Governing Body from joint authority with the CAISO Board of Governors to primary authority."[297] Going first is not as important as having the sole or final say. In isolation, without the dual-filing provision, Bonneville does not see the move from joint authority to primary authority as beneficial. Bonneville has repeatedly expressed its concern that, under primary authority, the CAISO Board of Governors may be insufficiently engaged and informed in the policy development for EDAM market design and revisions, as compared to joint authority.

Pathways disagrees with this concern, arguing that "Bonneville takes a considerable leap to warn of a hypothetical disconnect on market issues between the WEM [Governing Body] and Board of Governors under Primary Authority," and notes its proposal recommends continued collaboration.[298] Bonneville does not disagree that interested CAISO Board of Governors members could remain engaged. Bonneville's concern is simply that primary authority removes some of the procedural guardrails that have required a certain level of engagement.

Bonneville acknowledges that the dual-filing provision may provide incremental improvement as compared to the CAISO Board of Governors' potential veto power under joint authority. Nonetheless, Bonneville has significant concerns with Step 1's model of primary authority with dual-filing rights.

NIPPC references its experience with the Independent System Operator-New England (ISO-NE) dual-filing.[299] There is an important distinction between CAISO's and ISO-NE's dual-filing rights as to *which* bodies can make dual filings. In ISO-NE, the ISO-NE and New England Power Pool (NEPOOL) Participants Committee can make dual filings. Unlike the CAISO Board

[295] CAISO-040725 at 2-4; SCL-040725 at 15, 49-50, 52; NIPPC-040725 at 7.
[296] Pathways-040725 at 2-3.
[297] Pathways Step 2 Final Proposal at 10 (emphasis added).
[298] Pathways-040725 at 2.
[299] NIPPC-040725 at 7.

of Governors, the ISO-NE Board of Directors "must act with impartiality toward all Market Participants," rather than act for the benefit of a single state.[300] The NEPOOL Participants Committee is an independent, FERC-approved stakeholder advisory group. A more apt comparison might be if the WEM Governing Body and Regional Issues Forum (RIF) had dual-filing rights, rather than the CAISO Board of Governors. Unlike ISO-NE, Step 1 allows a California-appointed Board of Governors—with obligations to the market participants of a single state, and who may not have been deeply connected to the formation of tariff revision proposals—to have equal footing with decisions of the WEM Governing Body. EDAM's dual-filing provisions do not provide the same level of independence as ISO-NE's dual-filing provisions.

As discussed in Appendix B, Bonneville remains concerned with EDAM independence under the Step 1 revisions. Bonneville is concerned with the influence CAISO staff will have in the formation of proposals brought to the WEM Governing Body. But even after the full process resulting in the WEM Governing Body deciding to file a tariff revision, the dual-filing rights allow the California-appointed Board of Governors equal footing. Pathways notes it expects "the dual filing provision will encourage compromise between the WEM Governing Body and the CAISO Board."[301] While Bonneville values collaboration, it is not necessarily desirable to aim for a middle path between the decisions of a market's representative board and a California-appointed Board of Governors with duties to a subset of market participants.

Bonneville also questions the CAISO Board of Governors' authority during "exigent circumstances." CAISO and Pathways comments disagree with Bonneville's characterization of this authority. Bonneville understands that the process for tariff filings related to "time-critical exigent circumstances" is not the regular course and would likely be a rare occurrence. Bonneville does not disagree that the exigent circumstances exception requires a unanimous vote of the CAISO Board of Governors, or that a non-time-critical exigent circumstances would involve dispute resolution and dual-filing rights for the WEM Governing Body.

However, Bonneville disagrees that "time-critical exigent circumstances" is narrowly drawn. The CAISO Board of Governors has broad discretion to determine whether circumstances fall within these vague terms. While the CAISO Board of Governors must explain its rationale in writing, the Step 1 Final Proposal acknowledged that "[n]either the WEIM Charter nor the CAISO tariff define 'exigent circumstances' or 'time critical.'"[302] While this power is intended to

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[300] ISO New England Inc., Code of Conduct at 1 (Nov. 15, 2024), *available at* https://www.iso-ne.com/static-assets/documents/aboutiso/corp_gov/bylaws/code_of_conduct.pdf.
[301] Pathways-040725 at 2.
[302] *See* Pathways Launch Committee Step 1 Final Proposal at 9 (May 24, 2024), *available at* https://www.westernenergyboard.org/wp-content/uploads/Step-1-Recommendation_Final-Draft-Update-5.28.24-1.pdf.

be used as "a last resort,"[303] Bonneville remains concerned by the unilateral discretion held by an entity appointed by, and with obligations to, a single state.

In the event of a time-critical exigent circumstance, the WEM Governing Body does not have dual-filing rights, but is limited to including a statement or opinion. The CAISO Board of Governors may file "with no further WEM Governing Body consultation required . . . ."[304] The dispute resolution process between the WEM Governing Body and the CAISO Board of Governors would only be triggered following the time-critical exigent circumstance filing and FERC approval to "develop a durable solution to the circumstances giving rise to the filing."[305] This would leave in place the initial decision until such time as the dispute resolution process is completed and FERC filing accepted.

SCL asserts that, under Step 1, the WEM Governing Body has greater independence than SPP's MIP because SPP does not afford Markets+ the ability for FERC to ultimately resolve disputes.[306] Bonneville disagrees with this assessment. As discussed in Issue #17, Markets+ addresses independent governance in a more foundational way than dual-filing provisions, for example, through the SPP Board's independence from any one state and Markets+ being governed by a separate tariff than SPP's Integrated Marketplace.

Decision

As Bonneville discusses in the Policy, the broad concept of "time-critical exigent circumstances" is most likely to be called upon during moments of crisis, where independent judgement and expertise are most needed. Furthermore, Bonneville has accurately described and considered the current EDAM governance under Pathways Step 1. Bonneville updated Section 5.2.1.1 of the Policy to reflect updates to the Pathways Initiative.

ISSUE 16: Whether Bonneville accurately described and considered EDAM governance under Pathways Step 2 and the potential impact of SB540

Draft Policy Proposal

Section 5.2.1 and Appendix B of the Draft Policy discussed governance and finds that the independence of the Markets+ decision-making body is superior to that of the EDAM.

303 *Id.* at 10 n.22.
304 *Id.* at 8.
305 *Id.* at 10.
306 SCL-040725 at 14-15.

Public Comments

Several commenters agree with Bonneville that Markets+ governance is superior even to EDAM governance under Pathways Step 2 and proposed legislation. WPAG states, "In its current form, the West-Wide Governance Pathways Initiative fails to meet the mark for full independence, and for this reason it is unclear whether it will ever be able to achieve the requisite levels of transparency, collaboration, and equity . . . ."[307] PSE states, "In its current form, the Pathways proposal does not meet the mark for full independence."[308] PPC concurs that the Pathways step 2 proposal does not achieve fully independent governance.[309] The Joint Authors state, "The governance of EDAM does not provide a comparable structure [to Markets+] and would not be comparable even if the West Wide Governance Pathways Initiative 'Step 2' is fully implemented and the associated California legislation is passed."[310]

Snohomish "share[s] Bonneville's perspective that even if Pathways Step 2 is fully implemented (requiring a change in CA law), it would not achieve full independence . . . ." Snohomish's concerns include "significant intertwining of CAISO and the new Regional Organization, including shared staffing and a shared tariff," and CAISO retaining "the dual roles of a participating Balancing Authority for one part of the footprint and the market operator for the full footprint that could result in a conflict of interest."[311]

Powerex states: "While the West-Wide Governance Pathways Initiative (WWGPI) has led to some improvements for the region, the model simply cannot achieve the necessary requirements for full independence given the role of California ISO staff in driving priorities and acting as the market operator, as well as the oversight of a California-appointed board with obligations to prioritize California's interests. It is also highly problematic that WWGPI is simply adopting the EDAM platform which was not designed under a fully independent governance framework and poses risks, as was illustrated most recently in the identified design flaw in its treatment of congestion revenue."[312]

SCL "disagrees with BPA's assessment that the Pathways Initiative Step 2 proposal (Pathways Proposal) does not satisfy BPA's evaluation principles."[313] SCL asserts "the RO board acting as the decision-making body for EDAM would be independent and meet this standard" and "[t]he

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[307] WPAG-040725 at 1.
[308] Puget-040125 at 2.
[309] PPC-040725 at 7, 15.
[310] Joint Authors-040725 at 2.
[311] Snohomish-040725 at 3.
[312] Powerex-040725 at 2.
[313] SCL-040725 at 13.

legislation under consideration in the California legislature would create the only truly independent governance option between the two DAMs."[314]

SCL argues Bonneville "does not adequately discuss the changes that have been adopted by CAISO in recent years as a result of the Governance Review Committee recommendations, nor does it recognize that the changes in the Pathways proposal would introduce some of the elements that BPA prefers in Markets+, such as the ability for stakeholders to drive initiatives and indicative voting."[315]

NIPPC disagrees with Bonneville's characterization of the level of independence proposed in the Step 2 Final Proposal.[316]

Pathways asserts SB 540 "does not impose California's policies on other market participants."[317] Pathways states Bonneville "should further address Pathway's embedded respect for state and local jurisdictional authority . . . including the use of the Public Policy Committee of the RO Board and adding respect of state authority to set procurement, environmental, and reliability goals in the RO Corporate Documents." [318] Pathways alleges that Bonneville has changed its position to now require two separate tariffs to effectuate independent governance, citing August 2024 comments submitted as part of the Pathways process.[319]

Evaluation

Bonneville agrees with the conclusion of many commenters that Markets+ governance provides superior independence even if EDAM governance were to adopt the Pathways Step 2 proposal and California pass SB 540 as introduced.[320]

SCL asserts that "[u]nder the Pathways proposal, the RO board acting as the decision-making body for EDAM would be independent and meet [BPA's] standard."[321] Bonneville discusses governance as an evaluation principle in Section 4.1.6 of the Draft Policy. SCL's simplistic assertion ignores the continued role of the California-appointed CAISO Board of Governors, the RO's lack of independent oversight over market operations, the conflicts created by an integrated

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[314] *Id.* at 14, 50.
[315] *Id.* at 15.
[316] NIPPC-040725 at 7.
[317] Pathways-040725 at 6.
[318] *Id.* at 4.
[319] *Id.* at 4-5.
[320] *See e.g.*, WPAG-040725 at 1; Puget-040125 at 2; PPC-040725 at 7; Joint Authors-040725 at 2; Snohomish-040725 at 3; Powerex-040725 at 2.
[321] SCL-040725 at 14.

tariff, and the CAISO remaining the counterparty on contracts with market participants. Bonneville discussed its concerns with these aspects in the Draft Policy decision.

NIPPC argues that, if legislation is passed, then SPP's governance advantage disappears.[322] SCL goes further and argues this legislation would create the only truly independent governance option.[323] In comparing the two market offerings, Markets+ is superior to EDAM even as modified by Pathways Step 2 and SB 540.

Bonneville has considered the Step 2 recommendations of the Pathways Initiative, and the provisions of California Senate Bill 540 (SB 540) which would enable the Pathways recommendation. With the provisions and reservations contained in SB 540, Bonneville does not see that passage of the legislation will achieve the independent governance that is offered by Markets+. The Pathways Step 2 Proposal and provisions of SB 540 preserve advantages for the priority of California policies in EDAM.

SB 540 as introduced requires that the CAISO operate the EDAM market, conditions state participation on reporting for California's unique GHG accounting requirements and obligates California utilities to withdraw from EDAM if the CPUC determines changes in market rules "are detrimental to California consumers" or other California policy objectives.[324] SB 540 does not address the market continuing to be operated by CAISO staff answerable to the CAISO Board of Governors, EDAM tariff provisions continuing to be intertwined with the CAISO tariff, and the CAISO remaining the contractual counterparty.

Bonneville also continues to see a distinction in the selections of the governing boards for the entities that will serve as market operators. The SPP Board of Directors is independent of any state or entity. The CAISO Board of Governors remains appointed by the Governor of California, approved by the California Senate, with specific obligations to the interests of the people of California. Distinctions between the SPP and CAISO models are further discussed in Issue #17 herein.

Further, EDAM rests on a market design and policy framework historically developed to implement California's state policies. EDAM participants must take California's day-ahead market as they find it and extend it to EDAM with limited modifications. In contrast, Markets+ design is the product of collaborative decision making by participants and stakeholders that has been and will continue to be independent of any one state's policy requirements.

Pathways raises concerns with the markets' relative respect for state and local jurisdictional authority.[325] State participation within Markets+ is superior to that within EDAM. The Markets+

[322] NIPPC-040725 at 9.
[323] SCL-040725 at 49-50.
[324] SB 540 § 345.6(d).
[325] Pathways-040725 at 4-5.

States Committee (MSC) is intended, and has demonstrated itself, to provide an active role for policy representatives of state governments. State government staff participate in Markets+ working groups and task forces and seek to reconcile differing or conflicting state policies. Bonneville sees the MSC's role in the Markets+ Greenhouse Gas Task Force as a particularly helpful example. The MSC can also directly propose tariff amendments to the Markets+ Executive Committee (MPEC) and MIP. In contrast, EDAM under Pathways Step 2 would carry forward a role for the Body of State Regulators (BOSR) that is primarily educational for state utility regulators. While the BOSR may take positions by consensus, the BOSR charter states, "The purpose of the Body is to select a voting member of the EIM Governing Body Nominating Committee and to provide a forum for state regulators *to learn about* the EIM, EIM governing body and related ISO developments that may be relevant to their jurisdictional responsibilities."[326]

Pathways argues that SB 540 will not impose California policy development from California regulatory agencies.[327] This ignores the impact of the CPUC veto power discussed above in Issue #13 herein, which results from the threat of California utilities withdrawing from the market. More specifically, Pathways states, "In the example of greenhouse gas (GHG) policy . . . any utilities (California or non-California) evaluating participation in a day-ahead market [] will independently examine whether the market enables them to comply with their own applicable laws and policies."[328] While it is true that SB 540 will not impose California's policies on other market participants, the take-it-or-leave-it choice is distinct from the collaborative, multi-state engagement Bonneville has experienced with Markets+.

Pathways argues Bonneville "should further address Pathway's embedded respect for state and local jurisdictional authority" as well as "the use of the Public Policy Committee of the RO Board and adding respect for state authority to set procurement, environmental, and reliability goals in the RO Corporate Documents."[329]

Bonneville acknowledges the positive proposal in Pathways Step 2 final recommendation for a Public Policy Committee to provide a procedure for identifying potential conflicts with state procurement, environmental, reliability and other policies.[330] That proposal is carried forward as a requirement in California SB 540. However, the Public Policy Committee proposal, while significant and beneficial, remains reactive and does not envision state representatives working within the market governance framework to harmonize differing or conflicting state policies.

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[326] Western Energy Imbalance Market, BOSR Charter at 1 (Mar. 1, 2016), *available at* https://www.westerneim.com/Documents/EIM-BodyofStateRegulators-Charter.pdf (emphasis added).
[327] Pathways-040725 at 6.
[328] *Id.*
[329] *Id.* at 4.
[330] Pathways Step 2 Final Proposal at 61 (Ch. 3, Proposal § 2.c).

This incremental improvement is not on par with the collaborative engagement Bonneville has seen from the MSC.

While the Pathways Step 2 proposal revises the RO's corporate documents, it does not revise Section 345.5 or the CAISO Board of Governors' corporate documents. Rather than assure Bonneville, the differences between the RO's and CAISO Board of Governors' corporate documents serve to highlight the bias that the CAISO Board of Governors and CAISO staff are obligated to pursue.

SCL argues that BPA's analysis does not "recognize that the changes in the Pathways proposal would introduce some of the elements that BPA prefers in Markets+, such as the ability for stakeholders to drive initiatives and indicative voting."[331] Bonneville acknowledges that Step 2 included an increased role for stakeholders, and Bonneville welcomes that change. However, the details and timing of change are uncertain and untested. In contrast, Bonneville has firsthand experience with the Markets+ stakeholder engagement model. It has been used and tested through the Markets+ development process and has proven a successful model.

As a point of clarification, the August 2024 Bonneville statement that is referenced in the Pathways comments is taken out of context. The comments referenced were submitted in response to a presentation regarding *how* the CAISO tariff should be split out between the RO and the CAISO. In that context, it was stated that the tariff would be shared and the comments were regarding how the shared tariff should be handled if a single common tariff was a given. Bonneville's Day-Ahead Market Draft Policy Letter position that separate tariffs are a necessity to independent governance is consistent with Bonneville's comments on the Pathways Step 2 proposal submitted on October 25, 2024.[332]

Decision

Bonneville find that the consideration of state policies in the Markets+ governance structure is preferable, and that the Pathways Step 2 does not go far enough towards independence.

ISSUE 17: Whether Bonneville accurately described and considered the SPP Board of Directors' role in Markets+ governance

Draft Policy Proposal

Section 5.2.1 of the Draft Policy discusses the role of the SPP Board of Directors.

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[331] SCL-040725 at 15.
[332] Bonneville Power Admin., Comments on West-Wide Governance Pathways Step 2 Draft Proposal (Oct. 25, 2024), *available at* https://www.westernenergyboard.org/wp-content/uploads/G.-Bonneville-Comments-on-Pathways-Step-2-Draft-Proposal-Final.pdf.

Public Comments

Bonneville received comments supporting and expressing concern for the role of the SPP Board of Directors in Markets+. Comments focused on three areas: (1) SPP Board membership, (2) the SPP Board's ability to review MIP decisions, and (3) conflict of interest concerns.

a. SPP Board Membership

Many commenters expressed support for the "fully independent Board of Directors."[333]

Conversely, the State Agencies state "[t]hat SPP board is based outside the West and nominated through a process that currently excludes Western participants and stakeholders."[334] NWEC observe that "the SPP, Inc. Board of Directors [] is nominated and elected by the full SPP membership, primarily consisting of midwest utilities and developers. SPP's obligation is to its members, not the West and not the public."[335] The BlueGreen Alliance expresses disappointment that regional "stakeholders do not have a seat on the SPP Board of Directors" and that the "SPP Board of Directors' voting power is heavily weighted towards utilities."[336]

b. SPP Board's Ability to Review MIP Decisions

PPC comments that it does not have the same concerns over the role of the SPP Board of Directors that it does for the CAISO Board of Governors because "the scope of the SPP Board's decision-making on Markets+ issues is limited and appropriate."[337] PPC points to Section 4.1 of the Southwest Power Pool, Inc. Markets+ Tariff, which sets forth the limited circumstances in which the SPP Board may exercise oversight over Markets+.[338]

Conversely, the BlueGreen Alliance, SCL, NWEC, and RNW characterize the SPP Board's relationship with Markets+ and the MIP as one of "ultimate authority" and "final authority."[339]

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[333] Tacoma-040225 at 3; *see also* AWEC-040725; Big Bend-040725; CBEC-033125; CRPUD-040725; Hood River-040425; IFP-040725; Joint Authors-040725; Lincoln-040425; Mason-040725; Modern-040425; NRU-040725; Pacific-040725; Powerex-040725; PPC-040725; Puget-040125; Salem Electric-040725; Snohomish-040725; Umatilla-040425; Wasco-033125; WPUDA-031225.
[334] OR-WA State Agencies-040725 at 9.
[335] NWEC-040725 at 6.
[336] BlueGreen Alliance-040725 at 2.
[337] PPC-040725 at 6.
[338] *See* SPP, Markets+ Tariff, Attach. O § 4.1 (Apr. 18, 2025), *available at* https://www.spp.org/Documents/73635/Markets%20Plus%20Tariff_with%20compliance%20filing%20language_April%2018.pdf ("Markets+ Tariff").
[339] BlueGreen Alliance-040725 at 2; SCL-040725 at 3; NWEC-040725 at 6; RNW-040725 at 12 (RNW also asked BPA to "Please explain BPA's reluctance to support EDAM's governance structure because SB 540 demonstrates "California's continued policy influence over market design and outcomes" in light of the fact that the SPP Board of Directors retains ultimate authority over all decisions in Markets+."); *see also* OR-WA State Agencies-040725 at 9.

The State Agencies[340] submit a joint comment suggesting Bonneville should "address the Markets+ risks associated with a market participant-controlled governance process" and that the "process is overseen by the SPP board, which cannot delegate away its authority to the Markets+ Independent Panel."[341] SCL asserts "there is no indication that SPP's Board will be more responsible to BPA or Markets+ customers' needs" given that "Attachment O of the Markets+ tariff states clearly that SPP's Board will retain 'ultimate oversight of SPP's administration of Markets+.'"[342] NWEC comments that "ultimate oversight over decisions and financial issues is held by the SPP, Inc. Board of Directors, which is nominated and elected by the full SPP membership, primarily consisting of midwest utilities and developers. SPP's obligation is to its members, not the West and not the public."[343] RNW states, "While regional stakeholders can serve on various committees and provide proposals and advice to the SPP Board of Directors, the Board retains ultimate authority, and Section 205 filing rights, over all decisions."[344] CAISO characterizes the relationship between the MIP and the SPP Board as follows: "While the panel is described as holding the "highest level of authority for decisions related to the Markets+ market," the description goes on to explain this is at all times subject to "the SPP board of directors providing independent oversight." The tariff further states more generally that SPP's Board "provides ultimate oversight of SPP's administration of Markets+ subject to FERC regulatory jurisdiction."[345] CAISO submits that the Markets+ tariff may allow for overly broad review by the SPP Board, which would include "include a large portion of the decisions the MIP is charged with initially making."[346]

CAISO also takes issue with the appeal rights held by MIP members, one of which must be a sitting member of the SPP Board.[347] Any MIP member may appeal any MIP decision to the SPP Board.[348] CAISO believes this would allow the SPP Board "the unilateral ability to review and countermand [] or simply to veto the decision" of the MIP.[349] CAISO comments further that the MIP would not have a means "to place an alternative proposal before FERC for consideration."[350]

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[340] OR-WA State Agencies-040725 at 9. This comment was submitted jointly by Letha Tawney, Commissioner, Oregon Public Utilities Commission; Les Perkins, Commissioner, Oregon Public Utilities Commission; Colin McConnaha, Manager, Office of Greenhouse Gas Programs, Oregon Department of Environmental Quality; Brian Rybarik, Chair, Washington State Utilities and Transportation Commission; Jennifer Grove, Assistant Director, Energy Division, Washington State Department of Commerce; and Joel Creswell, Climate Pollution Reduction Program Manager, Washington State Department of Ecology.
[341] OR-WA State Agencies-040725 at 9.
[342] SCL-040725 at 3.
[343] NWEC-040725 at 6.
[344] RNW-040725 at 12.
[345] CAISO-040725 at 4 (internal citations omitted).
[346] *Id.*
[347] *Id.*
[348] *Id.* at 4-5.
[349] *Id.* at 5.
[350] *Id.*

c. Conflict of Interest Concerns

NWEC, CAISO, and SCL express concern that the SPP Board has a duty to SPP members rather than to Markets+, the West, or the public interest.[351]

CAISO contends that the "interests and positions of Markets+ stakeholders may diverge from the interests of SPP and the SPP Board because the SPP "Board has a duty to take into consideration the interests of its Eastern Interconnection members when exercising its ultimate governance authority over Markets+."[352] CAISO raises the examples of inadequate SPP staff resources to meet the needs of separate markets and prioritizing the positions of its larger, more established market in FERC processes and arguments.[353] CAISO suggests Bonneville should consider "that the multiple-separate-markets model raises its own unique challenges for managing potential competing interests," particularly because "stakeholders in Markets+ generally would not be members of SPP, which means their interests would be legally subordinate to the interests of SPP's members."[354]

SCL comments that "SPP would be the market operator for both the SPP RTO, RTO West, and Markets+, but BPA does not consider that SPP might have the same conflicts it imagines for EDAM."[355] SCL states that the SPP Board's ability to review certain MIP decisions with a material adverse financial or corporate risk to SPP result in a financial conflict of interest because the SPP Board has a fiduciary duty to the members of the RTO.[356] Moreover, SCL comments, the SPP Board may not be a neutral party in a seams negotiation between Markets+ and a neighboring SPP-run RTO.[357]

These concerns are not shared by all commenters. PPC, for example, commented:

> PPC is not concerned with SPP Board review resulting in inequitable consideration of stakeholder impacts as the SPP Board acts on broad, regional market interests. It does not have an obligation to provide additional protections for some market participants as compared to others. Additionally, the CAISO Balancing Authority Area (BAA) is included in the EDAM market footprint, giving the CAISO Board of Governors a potential conflict of interest in ensuring equity for all market participants while meeting their statutory obligations to protect the interests of the balancing area they oversee and, importantly, the California ratepayers they have been appointed to serve. The SPP RTO is not included in the Markets+ footprint and will not be co-optimized in the same market run as resources participating in Markets+.[358]

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[351] *Id.* at 5-6; SCL-040725 at 14-15; NWEC-040725 at 6.
[352] CAISO-040725 at 5-6.
[353] *Id.* at 6.
[354] *Id.*
[355] SCL-040725 at 3, 14-15.
[356] *Id.* at 14-15.
[357] *Id.* at 15.
[358] PPC-040725 at 6-7.

Evaluation

Bonneville addresses the three comment areas in turn: (1) SPP Board membership, (2) the SPP Board's ability to review MIP decisions, and (3) conflict of interest concerns.

a. SPP Board Membership

Bonneville is satisfied that the SPP Board of Directors is sufficiently independent, both in terms of composition and the nominating process.

As an initial matter, FERC has found "SPP's proposed Markets+ governance structure is just and reasonable and not unduly discriminatory or preferential."[359] FERC found Markets+ governance was sufficiently independent from undue influence because of the SPP Board's independence and because "the proposed provisions require that the Markets+ Independent Panel [MIP] *also* be independent of any market participant or market stakeholder . . . ."[360] Regarding EDAM governance, FERC "note[d] that CAISO's proposed EDAM governance structure is consistent with the existing WEIM governance, which the Commission previously concluded is just and reasonable."[361] FERC added, "However, we note that EDAM is a voluntary market and participants may seek recourse with the Commission if they believe CAISO or DMM is acting in an unduly discriminatory manner in administering EDAM."[362]

There is no regional requirement in the makeup of the SPP Board; members need not be based inside or outside any geographic area. Only one of twelve SPP Board members resides in the SPP Integrated Marketplace footprint while two members reside in the Pacific Northwest with previous industry experience at utilities in the Northwest.[363] In contrast, all five members of the California Board of Governors are based in California.

The SPP Board of Directors is elected by the SPP RTO membership. A party need not be a participant in Integrated Marketplace, or any SPP market for that matter, in order to join the SPP RTO and participate in the election of the SPP Board.[364] In contrast, the CAISO Board of Governors are selected by the California governor, albeit with stakeholder input from a nominating committee that recommends candidates to the governor, which limits the ability of stakeholders to have a role in its final selection.

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[359] *SPP*, 190 FERC ¶ 61,030, at P 363 (Jan. 16, 2025).
[360] *Id.* at P 364 (emphasis added).
[361] *CAISO*, 185 FERC ¶ 61,210, at P 484.
[362] *Id.*
[363] *See* SPP, Board of Directors/Members Committee, https://www.spp.org/stakeholder-groups-list/organizational-groups/board-of-directorsmembers-committee/.
[364] *SPP*, 190 FERC ¶ 61,030, at P 367 (Jan. 16, 2025); SPP, Markets+ Governance Frequently Asked Questions at 4 (Apr. 22, 2025), *available at* https://southwestpowerpool.s3.amazonaws.com/newsstories/Markets-Governance-FAQ_v3.pdf.

Because the SPP Board of Directors is independent in composition and nominating process, Bonneville does not share the commenters concerns that the SPP Board will unduly preference any region, sector, or stakeholder group.

b. SPP Board authority over MIP

Bonneville determines the SPP Board's oversight of Markets+ is preferable to even best-case governance currently contemplated by Pathways because the SPP Board is fully independent and the scope of the Board's oversight is limited.

PPC describes the SPP Board's scope of review as "limited and appropriate"[365] Indeed, such review is limited to the following:

1. Decisions of the MIP, after completion of the applicable Markets+ stakeholder process, that have a material adverse effect on SPP, including:
    a. Material agreements and material changes to those agreements between SPP and Markets+ Market Participants or SPP and Markets+ Market Stakeholders.
    b. Issues or concerns raised by the Market Monitor related to any FERC filing, rule or process within the scope of the Market Monitor's authority as established by FERC that has been previously raised to the MIP.
    c. Legal and/or litigation disputes or actions involving SPP or the implementation of Markets+; and
    d. Financial ramifications or corporate risk to SPP.
2. Markets+ budgets, any debt obligations related to Markets+, or material changes to SPP's staffing requirements.
3. Appeals of MIP decisions made pursuant to Section 4.2.1.[366]

Items 1 and 2 represent limited circumstances when institutional financial decisions may impact Southwest Power Pool, Inc., not markets operated by SPP. These provisions clarify Markets+'s responsibilities to SPP as the market operator, not to the Integrated Marketplace. Even then, the SPP Board is obligated to "give significant recognition and deference to the MIP decision-making role."[367]

SPP Board would only review a Markets+ market design decision would be if a MIP member appealed pursuant to subsection 3. In that case, the SPP Board would, "review the matter for resolution in consultation with the MIP."[368] Section 4.2.1 states, "Should the SPP Board of

[365] PPC-040725 at 6.
[366] Markets+ Tariff, Attach. O § 4.1.
[367] *Id.*
[368] *Id.*, Attach. O § 4.2.1.

Directors determine there is not sufficient consensus supporting the MIP's decision, and provided time allows, the SPP Board of Directors may remand the issue to the MIP and/or the appropriate Markets+ working group for further consideration." The SPP Board's review upon appeal is to "determine . . . sufficient consensus," and the only stated remedy is to "remand," "provided time allows . . . ." In the ordinary course, "SPP Staff is authorized to submit requisite regulatory filings to implement the MIP's decision."[369] Bonneville appreciates the consensus-building approach embedded in Markets+ governance and finds this appeal process is generally reflective of that approach.

Bonneville recognizes that the SPP Board has a measure of oversight over the MIP, and that the CAISO Board of Governors has a measure of oversight over the WEM Governing Body (through dual filing rights and under exigent circumstances) and over the proposed RO (through oversight of the market operator). Bonneville discussed its concerns with the CAISO Board of Governors' oversight earlier in this section and in Issue #15 herein. While some commenters compare the scope of these oversight provisions, there are important distinctions regarding the nature of the body exercising the oversight. Bonneville is concerned, not only with *when* oversight may occur, but *who* will be doing it. For example, Bonneville is less concerned with the SPP Board—with no statutory obligation to a specific state—to review whether to remand for sufficient consensus, than with the CAISO Board—subject to California Public Utilities Code § 345.5—to unilaterally file tariff revisions without RO approval during "time-limited exigent circumstances."

Bonneville recognizes that the SPP Board has limited and specific oversight over the MIP and Markets+, and concludes sufficient safeguards are in place that limit the scope of review and serve to promote consensus. Moreover, Bonneville finds comparisons to EDAM on this topic to be unpersuasive because of the lack of independence of the CAISO Board of Governors from the State of California.

c. Conflict of Interest

Bonneville considers the potential for conflicts of interest between the CAISO Board of Governors and the proposed RO Board to be greater than between the SPP Board and Markets+. This is even more so under the current CAISO EDAM governance model involving dual-filings.

First, SPP is fully outside the market footprint of not only Markets+, but also the other markets it operates. Unlike CAISO's dual roles within the same footprint as the market it operates (e.g., as a BA), SPP is not a BA in Markets+ or any other market for which it provides FERC-jurisdictional contract services. The Integrated Marketplace and Markets+ operate from entirely separate tariffs, so design decisions established through their respective stakeholder processes will govern only the market implementing the design decision.

[369] *Id.*

Second, the SPP Board's independence, as discussed above, limits the risk it will prioritize any one region, market, or policy over another. As a matter of practice, SPP has administered many different FERC-jurisdictional contract services such as Markets+. Bonneville is unaware of any complaint of discrimination being filed against SPP at FERC. In the case of seams negotiations, market footprints are not yet established and it is premature to lock in assumptions at this time. That said, if seams negotiations commence, each adjacent market would have a stakeholder process to address seams issues. To effectuate an agreement between the two markets, it is likely the parties would enter a joint operating agreement and each would make Federal Power Act section 205 filings to implement the agreement.

In the event the SPP Board became involved in the seams negotiation, the SPP Board would be obligated as a market operator to act in a non-discriminatory manner. The potential for procedural games, such as attempts by the SPP Board to delay seams-related tariff amendments by appealing and remanding for lack of consensus is low as evidenced from past practice. Moreover, the SPP Board is independent of any particular entity, region, or stakeholder group.

Third, Bonneville does not anticipate staffing issues to be a realistic concern for Markets+ because it expects the MPEC and MIP to continue to be appropriately staffed as established by Markets+ budgeting through the MPEC.[370] Markets+ uses a stakeholder-driven model, meaning stakeholders identify, prioritize, develop, and drive initiatives up through the various work groups and task forces—each of which are comprised of stakeholders who share the workload with SPP staff—to the MPEC and MIP. This is different from the CAISO staff-driven model where the same staff will work on policy initiatives for both EDAM and the CAISO BAA.

Fourth, SPP governance has a demonstrated track record of allowing differing policies among the markets it operates. While the Markets+ tariff was modeled on the Integrated Marketplace tariff, the stakeholders have developed unique design features in many areas using the work group and task force processes. In Bonneville's participation in these work groups and task forces, Bonneville has not experienced SPP staff opposing tariff language proposed by Markets+ stakeholders in order to achieve conformity with the Integrated Marketplace tariff. Bonneville views using the Markets+ consensus-oriented approach to effectuate change as inherently different than having a starting place of embedded policies that were developed under the political constraints of the state of California's policy interests and the interests of California entities.

Fifth, Bonneville disagrees that the SPP Board "might have the same conflicts it imagines for EDAM."[371] The CAISO Board of Governors is currently obligated by California Public Utilities

[370] *Id.*, Attach. O § 5.
[371] SCL-040725 at 3.

Code § 345.5 to center California interests. Even if passed, the introduced version of SB 540 does not change the ISO obligation to "operate consistent with the interest of the people of [California],"[372] the CPUC veto discussed above in Issue #13, or the GHG accounting discussed below in Issue #26-31. By comparison, the SPP Board is not beholden to any particular region or stakeholder group. Bonneville agrees with Joint Authors on the critical importance of an impartial market operator.[373]

Decision

In conclusion, Bonneville concludes that the SPP Board does not exert undue influence over Markets+, whether through the constitution of the SPP Board, the limited ability of the SPP Board to review decisions of the MIP, or the potential for conflicts of interest between the SPP Board and Markets+, the West, or the public interest. Bonneville views independence as one important factor for governance that is part of a bigger picture that must be viewed holistically. Considering the governance structures of these two markets, Bonneville finds that Markets+ governance better situates stakeholders for consensus-driven, durable solutions to future issues and areas of conflict.

C. EDAM and Markets+: Relative Stakeholder Engagement

ISSUE 18: Whether Bonneville accurately described and considered the different engagement models of EDAM and Markets+

Draft Policy Proposal

Section 5.2.1 of the Draft Policy discussed decision development and stakeholder engagement and concluded that the Markets+ process is the best approach to ensure a fair and equitable market across multiple states and fair consideration of Bonneville's objectives and obligations.

Public Comments

Several commenters explain that their preference for the Markets+ stakeholder-driven process over the EDAM staff-driven process is one of the reasons for their support of Bonneville's

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[372] California Public Utilities Code § 345.5(a).
[373] Joint Authors-040725 at 6-7 (listing examples of how "Market operator actions have undeniable impacts on market outcomes and market prices[:] extensive and asymmetrical use of load bias; blocking of EIM Transfers into the CAISO BAA in the Fifteen Minute Market; inaccurate implementation of the Resource Sufficiency Evaluation as applied to the CAISO BAA; and representation of coordinated intertie limits between the CAISO and adjacent BAAs as if these were constraints internal to the CAISO BAA, resulting in large congestion revenues being collected by the CAISO and allocated to its own customers for use of transmission facilities jointly funded by customers outside California.").

decision to pursue Markets+. NRU "agrees with Bonneville staff conclusions with respect to both the SPP Markets+ and CAISO EDAM governance structures, and values the independent, stakeholder-driven model that Markets+ provides . . . ."[374] Powerex agrees with Bonneville that "Markets+ provides transparent stakeholder engagement and equitable representation through the Markets+ Independent Panel, meaningful stakeholder voting rights . . . ."[375] Umatilla states that "Markets+ provides a strong governance and stakeholder process when compared to other day-ahead market options."[376]

Other commenters defend the EDAM model. CAISO "takes pride in its highly evolved, open and transparent stakeholder process" that leverages the independence and expertise of CAISO staff to resolve policy issues.[377] CAISO "is committed to continuing this evolution" and provides opportunities for stakeholders to present on issues in policy initiatives and to take on leadership roles, including directly engaging with Bonneville staff.[378] Meetings are also recorded and available online for the public.[379] CAISO states the RIF and Board of State Regulators play critical roles in stakeholder engagement, including in prioritization of policy initiatives and providing valuable feedback on market design.[380]

SCL "disagrees with BPA's assertion that the CAISO process is not transparent."[381] SCL contrasts Markets+, where "there is little documentation of how the work groups and task forces arrived at their decisions, what factors were considered, or the trade-offs of various policies," with EDAM's "detailed discussion and documentation of how the ultimate market design was settled on, and factors that were considered."[382] SCL appreciates EDAM's "extensive records of the comments of parties on different issues, which offers visibility into the various positions of each party, and the trade-offs considered in policy development."[383]

Pathways requests "that Bonneville clarify whether it prefers a process that requires more organizational time, expertise, and resources but that could lead to limited engagement from stakeholders representing critical customer and public interest perspectives who have more limited resources and staff."[384]

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[374] NRU-040725 at 2; *see also* PPC-040725 at 6.
[375] Powerex-040725 at 2.
[376] Umatilla-040425 at 2.
[377] CAISO-040725 at 7.
[378] *Id.*
[379] *Id.*
[380] *Id.*
[381] SCL-040725 at 16.
[382] *Id.*
[383] *Id.*
[384] Pathways-040725 at 5.

RNW requests that Bonneville explain whether it believes the weighted voting based on total load share in Markets+ is preferable to EDAM.[385]

Evaluation

Along with several commenters, Bonneville strongly prefers the Markets+ stakeholder-driven model over EDAM's CAISO staff-driven model.[386]

CAISO "clarif[ies] the record" regarding its "highly evolved, open and transparent stakeholder process."[387] SCL argues the CAISO process provides superior transparency by collecting comments and documenting decisions.[388] SCL asserts "BPA treats these stakeholder processes as though they are binary—as if one offers a means to engage with other stakeholders, collaborate, have their issues heard, and the other does not."[389]

Bonneville acknowledges and appreciates the advancements that the ISO has made in its stakeholder process, including the draft RIF Enhancements Plan, which proposes the CAISO integrate indicative voting and partner sector sponsors with CAISO staff. Bonneville does note that, while the RIF may provide input regarding the policy development roadmap under the CAISO EDAM, approval of the roadmap continues to be determined by CAISO staff without approval from the WEM Governing Body. The ability for stakeholders to prioritize initiatives is important. CAISO staff may have conflicting responsibilities and may prioritize and assign timelines differently than stakeholders would themselves.

Bonneville agrees that the two markets' stakeholder processes are not binary, but that there is a meaningful difference between SPP's more stakeholder-driven model and the CAISO's more staff-driven model. Bonneville understands that SPP and the CAISO use different approaches and tools in their efforts to achieve transparency. CAISO utilizes public comments in response to staff proposals and collects the accompanying documentation. Markets+ holds deliberations in public meetings, supported by staff serving as official secretaries, with stakeholders engaging directly in compromise and collaboration to work towards resolution on issues. Markets+ publishes minutes and reports indicative voting to decisionmakers.

Bonneville's observations and findings are based on its experience with the inherent structural differences between the CAISO and SPP stakeholder models. Bonneville has the highest respect for CAISO and its staff and appreciates the progress the CAISO has made in its stakeholder

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385 RNW-040725 at 12.
386 NRU-040725 at 2; PPC-040725 at 6; Powerex-040725 at 2; Umatilla-040425 at 2.
387 CAISO-040725 at 2, 7.
388 SCL-040725 at 16.
389 *Id.*

processes. In Bonneville's experience with both the CAISO and SPP stakeholder models, Bonneville finds SPP's robust stakeholder-driven approach to best suit its statutory business needs and the needs of its statutory customers. By design, SPP's approach relies more heavily on the time and expertise of market participants and stakeholders.

We acknowledge that different stakeholders may not prioritize the direct involvement required in the SPP process and prefer to rely on the time and expertise of CAISO staff.[390] These preferences are irrelevant to Bonneville's findings and conclusions and assessment of its own business needs. Bonneville finds that built into the Markets+ process is a framework for the development of stakeholder-driven recommendations resulting in fair and equitable outcomes for the market, as opposed to stakeholders playing a more reactive role to CAISO staff recommendations. Similarly, Bonneville's experience has been that the Markets+ approach better allows for discussion-based collaboration and compromise that yields a more equitable influence. For example, the use of voting provides transparency in positions and supports negotiation and compromise amongst the participants and stakeholders. Markets+ actions will be approved if the "average of the votes from all three sectors is at least 67%, with each sector representing one-third of the vote, meaning that two sectors cannot "drown out" an individual sector." This approach motivates stakeholders to develop consensus and promote durable decision making.

Bonneville agrees with PPC's observation that the stakeholder-driven approach in Markets+ has resulted in innovative solutions with broad support. For example, Bonneville has found stakeholder driven work groups and task forces to be beneficial during the design of Markets+. Bonneville recognizes the level of time and commitment of market participants and stakeholders to engage in collaborative decision making may be greater at times but believes that more informed and durable decisions will be the outcome. Moreover, SPP provides dedicated staff to Markets+ working groups, committees, and task forces.[391] Finally, Bonneville has determined that the stakeholder-driven model allows entities to participate as fully or as narrowly as they choose.

Decision

Bonneville's business needs are best met by the Markets+ stakeholder-driven process because it is specifically designed to facilitate consensus-driven, innovative, durable, and fair market design outcomes.

[390] *See* CAISO-040725 at 7.
[391] Markets+ Tariff, Attach. O § 5.

ISSUE 19: Whether Bonneville accurately described and considered the markets' inclusion of constituencies

Draft Policy Proposal

Section 5.2.1 of the Draft Policy discussed decision development and stakeholder engagement and concluded that the Markets+ process is the best approach to ensure a fair and equitable market across multiple states and fair consideration of Bonneville's objectives and obligations.

Public Comments

Many commenters support the governance structure of Markets+ governance.[392] NRU "values the independent, stakeholder-driven model that Markets+ provides, along with the ability of market participants and independent organizations to engage constructively in organizational decision making."[393] PPC commented that "the participatory stakeholder structure in Markets+ provides a preferred method for policy development. It is PPC's observation that this process allows greater collaboration among stakeholders, provides a greater amount of transparency on stakeholder perspectives and decision-making, allows stakeholders to play a more active role in determining what policy and market design changes are prioritized, and has facilitated aspects of market design that meet BPA's needs but apply broadly to all market participants (ex. 1A attribution for GHG)."[394]

Other commenters suggest that the stakeholder process of Markets+ is inaccessible and "does not allow public input."[395] The BlueGreen Alliance states, "[s]tates and other stakeholders who represent broader public interests have few meaningful or accessible venues to influence decision making in Markets+. While regional stakeholders can serve on various advisory committees, most participation requires an onerous membership fee and these stakeholders do not have a seat on the SPP Board of Directors."[396] Save Our Wild Salmon (SOS) comments that EDAM has "clear roles in governance for public interest participants while Markets+ is a member-based trade association with barriers and costs for public interest participants."[397]

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[392] AWEC-040725; Big Bend-040725; CBEC-033125; CRPUD-040725; Hood River-040425; IFP-040725; Joint Authors-040725; Lincoln-040425; Mason-040725; Modern-040425; NRU-040725; Pacific-040725; Powerex-040725; PPC-040725; Puget-040125; Salem Electric-040725; Snohomish-040725; Tacoma-040225; Umatilla-040425; Wasco-033125; WPUDA-031225.
[393] NRU-040725 at 2.
[394] PPC-040725 at 6.
[395] Miller-033125; Brewer-040725.
[396] BlueGreen Alliance-040725 at 3.
[397] SOS-040725 at 2.

Evaluation

Bonneville disagrees with the contention that Markets+ does not allow public input and that EDAM will allow greater influence for public interests and constituencies. There are a number of avenues for entities with various perspectives to participate in Markets+. The "MPEC provides a forum for interested entities—including market participants, market stakeholders, non-voting stakeholders, and Markets+ State Committee members—to participate in the governance of Markets+."[398] In addition, MPEC must consider "system or process enhancement proposals recommended by SPP, the MSC, Markets+ Market Participants, Markets+ Market Stakeholders, Markets+ Non-Voting Stakeholders or any designated working group, committee or task force established by the MPEC."[399] These processes explicitly allow stakeholders of all kinds to participate in Markets+ governance.

Not only can all stakeholders engage in governance, but also they can participate in developing market design. MPEC and Markets+ workgroup meetings are open to the public. Any participant can raise issues, suggest policy proposals and engage in discussions to advocate for positions that align with their business and public interests in the meetings when design is developed.

Indeed, public interests are well represented in Markets+, and Markets+ does not impose prohibitive costs on stakeholders. SPP is organized as a 501(c)(6), which is a non-profit entity.[400] Markets+ governance also embeds public interest protections and input in its tariff. Notably, the Markets+ Nominating and Governance Committee must include a member representing public interest organizations and consumer advocates.[401] Entities that are not market participants are able to join and participate as Markets+ Market Stakeholders for a small fee, which may be waived for non-profit organizations and state-chartered consumer advocate offices.[402] Bonneville is not aware of cost prohibiting any non-profit organization from participating in Markets+ and is aware of several instances where such fees have been waived for non-profit organizations.

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398 *SPP*, 190 FERC ¶ 61,030, at P 365.
399 Markets+ Tariff, Attach. O § 4.3.1.
400 SPP, Independent Auditor's Report and Financial Statements (Dec. 31, 2023 and 2022) at 9, *available at* https://www.spp.org/documents/71744/2023%20spp%20audit%20report.pdf.
401 Markets+ Tariff, Attach. O § 4.5.1.
402 *Id.* § 2 (Definition of Markets+ Market Stakeholder ("MMS")).

Decision

By design, Markets+ ensures robust, adequate, and effective opportunities for comment and participation from public interests and constituencies in the Markets+ stakeholder processes.

ISSUE 20: Whether Bonneville appropriately considered the role of states in its decision

Draft Policy Proposal

Section 5.2.1 of the Draft Policy discussed reasonable harmonization of state policies and determined that the equivalent consideration of state policies by the Markets+ governance design is superior to that of the EDAM.

Public Comments

The BlueGreen Alliance expresses that EDAM has a "clearer and more substantive role for state regulators and elected officials," which ensures state independence and acknowledgement of state policies.[403] CAISO states:

> The Body of State Regulators (BOSR) . . . plays a critical role in the development of market rule changes through active participation in stakeholder initiatives with independent staff support, providing valuable feedback that is carefully considered in the stakeholder process. [CAISO], along with other technical experts, frequently participates in BOSR meetings to provide detailed explanations of market design choices under consideration in the stakeholder process, their implications and the tradeoffs to be considered before design changes are finalized. . . . A member of Bonneville staff serves as the WEM-BOSR liaison for the power marketing sector . . . .[404]

SCL contends that Bonneville misrepresents CAISO's relationship with state policy, and that "City Light and Washington polices have not been treated on a lesser basis."[405] SCL states that, "[a]s a Washington utility that is subject to the CCA and multiple other emissions-related programs, and that also sells specified-source energy to California, City Light has works closely with CAISO on these topics [and o]verall, our experience is that CAISO is responsive to our needs, actively engaged with and collaborating with the regulating agencies, and available for

[403] BlueGreen Alliance-040725 at 3.
[404] CAISO-040725 at 7-8.
[405] SCL-040725 at 17-18.

assistance as we learn to navigate these nascent programs."[406] SCL notes "CAISO currently has a GHG stakeholder initiative where it is reviewing potential enhancements."[407]

Evaluation

Bonneville acknowledges that SCL has had a positive experience working with CAISO to harmonize state GHG programs. In the Policy, Bonneville used GHG to illustrate the importance of states' roles and how the Markets+ structure facilitates collaboration and harmonization.

The record shows that the MSC offers a more substantive role for state entities to participate in a day-ahead market, including in market design. The MSC will be comprised of one member from each state with generation or load in the Markets+ footprint, and each such member will be appointed by the utility regulatory commission of the applicable state.[408] The MSC's role is to provide advice to the MIP, the MPEC, and any working group or task force.[409] The MSC can directly propose tariff amendments to the MIP.[410] The Markets+ tariff enshrines funding, support, and access to data for the MSC.[411]

Additionally, MSC members and other state officials "are eligible for appointment to Markets+ task forces."[412] The Markets+ Nominating and Governance Committee must have one member of the MSC. Individual MSC members have the right to appeal decisions to the MIP.[413]

In contrast, the charter for the EIM BOSR describes the BOSR role as primarily informational. The charter defines BOSR's purpose as being "to provide a forum for state regulators to learn about the EIM, EIM governing body and related ISO developments that may be relevant to their jurisdictional responsibilities."[414] The charter also states that the BOSR "may express a common position in ISO stakeholder processes or to the EIM Governing Body on EIM issues."[415]

As a market participant operating across multiple states, Bonneville sees significant benefit to market design when states have a robust ability to collaborate and harmonize state policies. Bonneville would support the WEM BOSR playing both a more active role in harmonizing state policies and bringing broader representation on behalf of the states. Ultimately, however, Markets+ provides more extensive and complete opportunities for state involvement.

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[406] *Id.*
[407] *Id.* at 18.
[408] Markets+ Tariff, Att. O § 4.3.2.1.
[409] *Id.*
[410] *Id.*, Attach. O § 4.2.1.
[411] *Id.*, Attach. O §§ 4.3.2.3, 4.3.2.4.
[412] *Id.*, Attach. O § 4.3.2.1.
[413] *Id.*, Attach. O § 7.
[414] Western Energy Imbalance Market, BOSR Charter at 1.
[415] *Id.*

Decision

By design, Markets+ provides more extensive and complete opportunities for state involvement. The formal structure of Markets+ governance will also ensure adequate and equitable representation for states and regulators.

5.2.2. Resource Adequacy and Resource Sufficiency

ISSUE 21: Whether Bonneville appropriately assessed Resource Adequacy and Resource Sufficiency design

Draft Policy Proposal

Bonneville discussed RA and RS design in Section 5.2.2. of the Draft Policy.

Public Comments

Big Bend Electric Cooperative (Big Bend), Cowlitz PUD No. 1 (Cowlitz), Hood River Electric & Internet Cooperative (Hood River), Central Lincoln PUD (Lincoln), Modern Electric Water Company (Modern), Pacific PUD (Pacific), and Columbia River PUD (CRPUD) support Bonneville's assessment that participation in Markets+ is preferable because it has "uniform resource adequacy requirements."[416]

The Joint Authors support the Markets+ design, stating that "a common and rigorous resource adequacy structure is foundational to reliability and critical to achieving equitable outcomes within a market footprint."[417] They also state that WRAP will prevent leaning on other market participants, ensures capacity obligations are distributed equitably, provides visibility into the resource performance, and provides deliverability requirements incentivizing "long-term transmission development, supporting reliable service to customers and the efficient integration of clean energy resources."[418] They assert that the EDAM design presents "challenges in accurately applying [sufficiency] tests, insufficient failure consequences to prevent deliberate leaning, and insufficient notice of a deficiency due to the late timing of the test."[419]

PPC "agrees with BPA's evaluation that participating in a common RA program is important for demonstrating the reliability of the market."[420] PPC states that resource sufficiency tests "do not

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[416] Big Bend-040725 at 1; Cowlitz-040725 at 1; Hood River-040425 at 1-2; Lincoln-040425 at 1; Modern-040425 at 1; Pacific-040725 at 1; CRPUD-040725 at 1.
[417] Joint Authors-040725 at 2.
[418] *Id.* at 2-3.
[419] *Id.* at 4.
[420] PPC-040725 at 4, 16.

send the important signals that are needed to ensure that investments in generation and transmission are adequate to meet reliability needs on a long-term basis" and " a common RA program ensures equitable contribution to the reliability of the region from all participants and creates the opportunity for the region to more efficiently meet demand across the market footprint."[421] WPAG comments that the RA requirement in Markets+ may prove to have important implications and efficiencies for future long-term power sales contracts.[422]

Snohomish comments that EDAM's lack of an RA requirement "leaves the market relying solely on the resource sufficiency evaluations in the operational time frame." They argue that "[t]he lack of a long-term planning standard leads to more complex requirements and more onerous consequences for failure in order to disincentivize 'leaning' on the market in the near term."[423]

Tacoma states that the RA requirement is "a meaningful advantage of Markets+ over EDAM."[424] Tacoma also states that "[t]his difference in market design results in a greater risk within EDAM that participants could be forced to over-procure capacity, a result with costs that could potentially surpass any production cost savings."[425]

Powerex also supports the Markets+ RA design, stating that it "ensures all participants bring forward adequate resources and are held to consistent standards applied under an independent governance framework, without 'leaning.'"[426] Powerex states that "EDAM uses a last-minute test to validate the quantity of supply made available from each BAA, with weak consequences for shortfall that enables leaning and fails to provide an effective incentive for entities to secure sufficient supply in advance. Powerex continues that the EDAM design "is not only inequitable, but it also increases the chances that the overall market footprint will have less supply than necessary to support reliability."[427] Powerex also comments that there is a "inherent conflict of interest" in CAISO applying the resource sufficiency tests to itself, stating that the "CAISO BAA [is] able to 'pass' . . . even during periods when it was clearly not sufficient (*e.g.,* during energy emergencies)."[428]

CAISO comments that the EDAM design is intended to allow participants to use "any long-term resource procurement that the participants establish . . . to support the RSE [resource sufficiency evaluation]."[429] CAISO also states that Bonneville's argument that EDAM "isolates participants

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[421] *Id.* at 4.
[422] WPAG-040725 at 3.
[423] Snohomish-040725 at 3-4.
[424] Tacoma-040225 at 5.
[425] *Id.*
[426] Powerex-040725 at 2.
[427] *Id.*
[428] *Id.*
[429] CAISO-040725 at 10.

when they do not meet their resource sufficiency obligation" is inaccurate.[430] According to CAISO, "[i]n EDAM, failure to pass the day-ahead RSE does not limit transfers but may expose the entity to financial surcharges that act as an incentive to take steps to meet the daily sufficiency obligation based on next day forecasted conditions."[431]

CAISO also states that "[f]ailure of the real-time RSE (in the WEIM) also does not limit transfers, but the entity has the discretion to establish whether to limit transfers to its balancing area for projected fifteen-minute intervals of insufficiency or continue to receive energy though Assistance Energy Transfers (AET)."[432] CAISO continues by stating that it worked with participants on the AET concept, leaving the "determination of how to manage market transfers when the entity does not pass the real-time resource sufficiency with each balancing area."[433] CAISO concludes that "[t]hese factors all ensure a robust day-ahead and real-time resource sufficiency evaluation that is not predicated on imposing participation in a single resource adequacy or resource planning program."[434]

NIPPC comments "that given the uncertainties around the WRAP, Markets+ does not have any real advantage over EDAM."[435] SCL disagrees about WRAP requirements as the focus of evaluating the RA/RS design. SCL states that "footprint and connectivity will play an important role in operational reliability that cannot be captured entirely through an RA program alone" and that "a common RA standard . . . does not outweigh the reliability value of a diverse, well-connected footprint."[436] SCL also comments that "the EDAM approach allows for treatment of different state policies and compliance policies on an equal basis" and questions if Bonneville will still join Markets+ should WRAP not move forward.[437] Finally, SCL also points out that CAISO's AET concept allows entities to stay in the market even if an entity fails resource sufficiency tests.[438]

Evaluation

Bonneville finds that the uniform RA requirement of Markets+ is superior to the EDAM approach of allowing different RA metrics. As stated in the Draft Policy, the Markets+ requirement that all entities participate in WRAP "standardizes, simplifies, and solidifies each market participant's requirements to bring sufficient resources to the market to serve its

[430] *Id.* at 10-11.
[431] *Id.*
[432] *Id.*
[433] *Id.*
[434] *Id.*
[435] NIPPC-040725 at 4.
[436] SCL-040725 at 38.
[437] *Id.* at 38-39.
[438] *Id.*

loads."[439] CAISO and SCL assert that there is no deficiency in the approach which allows EDAM participants to use "any long-term resource procurement" to ensure RA. However, Bonneville's assessment is that this approach will place too much reliance on the real-time RSE by creating uncertainty about whether resources will be sufficient to serve load in advance of operations.[440]

For this reason, the agency views the EDAM approach as not providing a mechanism that ensures equal and prudent planning and resource acquisition in the longer term, which results in no clear visibility into whether the EDAM footprint as a whole will have adequate resources in the planning horizon. As reinforced by other commenters, this approach could continue to result in leaning as it lacks the independent framework associated with WRAP. The Joint Authors state, "[r]esource sufficiency tests applied in the operating timeframe without the underpinning of a common resource adequacy program are inherently challenging for several reasons[,]"including "challenges in accurately applying such a test, insufficient failure consequences to prevent deliberate leaning, and insufficient notice of a deficiency due to the late timing of the test."[441] Bonneville agrees with this assessment.

Bonneville acknowledges CAISO's explanation that the AET allows BAAs to avoid isolation from the market in the event of an RSE failure.[442] However, the AET is not a substitute for a uniform RA requirement that will ensure footprint-wide RA planning. While the AET prevents isolating BAAs from the market, the EDAM resource sufficiency design still does not require any standardized long-term planning metrics by EDAM entities. EDAM entities could potentially fail to adequately plan for adequacy or find it more economical to pay the AET, which could undermine the purpose of an RA metric by allowing for leaning on other market participants to ensure resource sufficiency. In contrast, Markets+ prevents leaning by requiring all market participants to participate in WRAP and thereby ensuring resource adequacy and resource sufficiency based upon a common metric.

Bonneville disagrees with NIPPC that the Markets+ WRAP requirement does not provide any advantage over EDAM because of uncertainty around WRAP. FERC approved the WRAP tariff on February 10, 2023, which stood up the independent governance structure and set participation terms and conditions.[443] There is no FERC-approved resource adequacy metric required for EDAM participants. With the WRAP requirement in the Markets+ design, entities will be required to meet it in order to participate in the market. As more entities join Markets+, WRAP participation will be bolstered. Moreover, in the unlikely event that WRAP were to dissolve,

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[439] Draft Policy at 43.
[440] CAISO-040725 at 10.
[441] Joint Authors-040725, App., Issue Alert 2 at 4.
[442] *Id*. at 10-11.
[443] 182 FERC ¶ 61,063 (Feb. 10, 2023).

Markets+ participants will be well positioned to replace the WRAP requirement with an alternative program developed through the independent governance framework.

Bonneville also disagrees with SCL's assertion that the market footprint itself should be the main focus of Bonneville's evaluation rather than a uniform RA metric. A large, interconnected footprint could improve potential optimization benefits for some entities, but it would be imprudent for Bonneville to deprioritize all other relevant factors to its business based solely on the size of the market and the independent business decisions of neighboring balancing authorities. Indeed, RA is an important, relevant factor to Bonneville's day-ahead market policy direction. Bonneville continues to conclude that the uniform RA metric in Markets+ provides more benefit for Bonneville and its customers by ensuring RA in the planning horizon, in turn supporting RS in the operational horizon.

Decision

The Markets+ RA and RS design will better ensure reliability by employing a common planning metric which in turn will promote sufficiency in the operational horizon. Based upon the additional discussion herein, Bonneville updated the section 5.2.2 of the Policy to discuss AETs in EDAM.

5.2.3. Price Formation and Market Power Mitigation

ISSUE 22: Whether Bonneville evaluated EDAM's Imbalance Reserve Product

Draft Policy Position

In Section 5.2.3 of the Day-Ahead Market Draft Policy, Bonneville described how CAISO created Imbalance Reserve Product, which recognized the need to procure additional flexible products that can be economically awarded to help provide additional capacity and reduce out-of-market actions by the market operator.

Public Comments

CAISO and SCL comment on the EDAM Imbalance Reserve Product. CAISO suggests that Bonneville undervalued the EDAM Imbalance Reserve Product in its market design evaluation, asserting that it "appropriately values the flexible attributes of the FCRPS and its ability to respond to rapid changes in grid conditions to manage uncertainty between day-ahead and real-time driven by changes in load, solar and wind forecasts, and other factors."[444]

[444] CAISO-040725 at 11-12.

SCL comments that Bonneville had changed its position on the Imbalance Reserve Product compared with the position Bonneville stated on the Imbalance Reserve Product in its EIM Record of Decision.[445] SCL further suggests that the Markets+ Reliability Backstop design does not provide fair compensation and thus is inferior to the EDAM design of the Imbalance Reserve Product. They argue that in addition to not having an Imbalance Reserve Product, in situations when additional capacity is needed, the Markets+ "reliability backstop" allows the market operator to "commit additional available resources that were not otherwise offered to the market to relieve the capacity shortage if needed." They assert that "[t]his arrangement is at odds with BPA's stated position on fair compensation for capacity."[446] SCL states that Markets+ stakeholders considered inclusion of the Imbalance Reserve Product in Markets+ market design, but that they could not agree and there is no timeline for when it may be revisited.[447]

Evaluation

Bonneville recognizes that the Imbalance Reserve Product could help address uncertainty between the day-ahead and real-time operational horizons. Bonneville supported the development of the Imbalance Reserve Product in EDAM because the footprint had a demonstrated need for such a product. This need was due to the uncertainty swings in the load-resource balance caused by the variable renewable resource mix within the footprint and the need for dispatchable resources that are deliverable and can ramp between fifteen-minute operational intervals.[448] The product was designed to incentivize flexible resources to economically participate and to reduce the need for grid-operator biasing and out of market actions.

In response to SCL's contention that Bonneville has changed its position, context is important. When CAISO's Day Ahead Market Enhancements (DAME) initiative was in the design phase, Bonneville strongly supported the development of the Imbalance Reserve Product; however, the product has not been implemented in advance of EDAM. Ultimately, CAISO decided to implement DAME and EDAM initiatives concurrently, even though the Imbalance Reserve Product design was finalized in May 2023.[449] Bonneville and other stakeholder support for the product deteriorated over time, particularly in the final stages of the product's evolution.

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[445] SCL-040725 at 42.
[446] *Id.* at 42 (citing Markets+ Tariff, Attach. A § 2.2.2(b)).
[447] *Id.*
[448] CAISO, Day-Ahead Market Enhancements, Stakeholder Technical Workshop presentation at 6 (June 20, 2019), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Day-AheadMarketEnhancementsWorkshop-Jun20-2019.pdf.
[449] Bonneville disagrees with CAISO's characterization of the Imbalance Reserve Product as a stakeholder success for Bonneville and its ability to advocate on behalf of products and to have them successfully developed and implemented. Bonneville sees this product as a once-promising product that changed during the stakeholder process to decrease transparency and is an example of California-centric perspectives being prioritized in CAISO stakeholder processes.

Bonneville's views were transparent and are reflected in its public comments, which are available on the CAISO stakeholder page.[450]

Although Bonneville supports the benefits from a product like the Imbalance Reserve Product, Bonneville has concerns about later-stage changes to its design. Namely, Bonneville is concerned that CAISO plans to implement tunable parameters for Imbalance Reserve Product procurement, allowing the market to procure less Imbalance Reserve Product under conditions where supply is more costly. CAISO also plans to administer Imbalance Reserve Product procurement using model-based deployment scenarios, not based on actual bids submitted to the market. Bonneville is also concerned that insufficient Imbalance Reserve Product may be procured at times when the need is most critical, which could contribute to scarcity conditions. Ultimately, these practices will obscure transparent and accurate price formation, which is problematic because they will also be administered at the market operator's discretion.

While Bonneville supported the inclusion of a similar product in the Markets+ design, some Markets+ stakeholders were not convinced of the need for such a product in the design because unlike EDAM, Markets+ includes a uniform resource adequacy program. While Markets+ does not include a similar product, the inclusion of the WRAP RA metric includes financial incentives to ensure equitable procurement of capacity to prevent leaning on the capacity of others, as well as compensation for holdback and energy deployment in the operational horizon. Bonneville accepted the position that developing a similar product in Markets+ without a demonstrated need could impose additional and unnecessary costs to load service and agreed to move the topic to the Markets+ "parking lot" for consideration after go-live. Bonneville will monitor Markets+ and consider whether a similar product would be necessary or beneficial to the Markets+ design and require prompt consideration through the Markets+ stakeholder process.

As to comparisons drawn between Imbalance Reserve Product and the "reliability backstop" in Markets+, Bonneville finds these comparisons to be unpersuasive because the Imbalance Reserve Product would be included in all day-ahead market runs while the reliability backstop would be only included in unexpected scarcity conditions, which should be rare. Bonneville's assessment is that Markets+ design has a robust industry-standard scarcity pricing approach, which diminishes concerns that there is insufficient compensation for such imbalances when scarcity conditions are triggered because the "reliability backstop" product is settled as a component of the LMP, even though it is not a standalone biddable product.

[450] *See* CAISO, Day-Ahead Markets Enhancements Initiative (comments submitted by Bonneville, Western Power Trading Forum, Vistra, The Energy Authority, and Powerex), *available at* https://stakeholdercenter.caiso.com/StakeholderInitiatives/Day-ahead-market-enhancements.

Decision

Bonneville affirms its policy position regarding the Imbalance Reserve Product based on consideration of the design differences between EDAM and Markets+. Bonneville updated its discussion in Section 5.2.3 of the Final Policy to further discuss the Imbalance Reserve Product.

ISSUE 23: Whether Bonneville considered differences in price formation, including fast-start pricing and scarcity pricing

Draft Policy Proposal

In section 5.2.3. of the Day-Ahead Market Draft Policy, Bonneville described the importance of transparent and equitable price formation to ensure accurate price signals are provided to the entire market footprint. Bonneville determined that Markets+ would better ensure fair and accurate compensation for both Bonneville's flexible and reliable generation and for the entire market footprint because it includes fast start pricing (FSP) and footprint-wide scarcity pricing while the EDAM design does not.

Public Comments

The Joint Authors support Bonneville's emphasis on accurate price formation design practices. The Joint Authors describe how most participants, including Bonneville, will be net buyers and net sellers at different times of the year and/or under different conditions. They describe how "[e]nsuring market prices are accurate provides the greatest assurance of long-term benefits that are equitably distributed under the full range of potential circumstances."[451]

The Joint Authors concur that there are key differences between Markets+ and EDAM with respect to market power mitigation, scarcity pricing, and fast-start pricing. They assert that "these are important areas in which the market design of Markets+ and EDAM differ significantly with implications that are not accurately measured in production cost models." They agree with Bonneville's conclusion that the Markets+ price formation practices are superior to EDAM in each area.[452]

The Joint Authors further opine that "Markets+ includes a scarcity pricing approach that is specifically designed to ensure that market prices can rise gradually as the quantity of available flexible reserves begins to fall and the risk of an energy shortfall increases." They explain that this design will ensure that prices appropriately reflect scarcity conditions.[453] They explain that the EDAM framework does not include scarcity pricing for the EDAM footprint, instead it is generally linked to ancillary service shortfalls in the CAISO BAA alone (rather than the broader

[451] Joint Authors-040725 at 4.
[452] *Id.* at 3.
[453] *Id.* at 4.

EDAM footprint). They explain that "the effectiveness of this approach is frequently undermined by extensive manual interventions that commonly occur in the CAISO BAA during scarcity conditions, including deploying out-of-market supply and emergency demand response." The Joint Authors link this approach to inaccurate downward pressure on market prices, pricing results that are inconsistent with system conditions, and limiting incentives for market participation.[454]

PPC agrees with Bonneville's evaluation of price formation issues, including the importance of fast start pricing. They assert that "[p]revious PPC analysis has demonstrated the value of fast start pricing to BPA and other suppliers in the Northwest."[455] From an Energy GPS study on fast-start pricing, commissioned by PPC and Powerex, PPC estimates that "implementing fast-start pricing in the CAISO market would increase revenues to those with surplus generation in the Pacific Northwest (including BPA) by $200 million annually."[456] Based on this estimate of the potential benefits from fast-start pricing, along with the other factors that PPC cites regarding PCM drivers, PPC asserts that "the $65-$221 million that has been cited drastically overstates the difference in economic benefits between Markets+ and EDAM."

Powerex agrees that the Markets+ approach to price formation better reflects operational conditions and equitable market outcomes, which will provide "appropriate price signals under a range of potential conditions while also incenting long-term investment where appropriate."[457] Citing the same Energy GPS study, they conclude that the "annual estimated regional cost shift of $93-$185 to the detriment of Northwest ratepayers and $95-$235 million to the detriment of Southwest ratepayers, while benefiting California LSEs by as much as $1.3 billion per year in reduced costs of both imported energy and in- state purchases from merchant generators."[458]

Idaho Falls Power acknowledges that Markets+ has "proper price formation."[459]CPC notes that "[w]ithout moving forward, BPA and its customers forgo an optimized resource dispatch that lowers the cost of power for BPA's customers through transparent price formation and better compensation for BPA's flexible resource fleet."[460]

[454] *Id.* at 5.
[455] PPC-040725 at 17.
[456] *Id.* at 11 (citing Powerex and PPC, The Importance of Fast Start Pricing in Market Design: Including the Cost of Starting and Operating Natural Gas Peaking Units in Wholesale Market Prices (June 2022), *available at* https://powerex.com/sites/default/files/2022-06/The%20Importance%20of%20Fast%20Start%20Pricing%20In%20Market%20Design%20-%20June%202022.pdf ("Study on Fast-Start Pricing")).
[457] Powerex-040725 at 2.
[458] *Id.* at 5 (citing Study on Fast-Start Pricing).
[459] IFP-040725 at 2.
[460] CPC-040725 at 1.

SCL argues that the inclusion of fast-start pricing in the Markets+ design should carry little weight in Bonneville's assessment of the market options, and that its perceived value for the Pacific Northwest is likely higher than its actual value.[461] SCL argues that WMEG analysis shows that fast-start pricing "has less of an impact in the Pacific Northwest portion of the Markets+ footprint, due to transmission constraints getting from the Northwest to the Southwest or Rockies area while avoiding transmission through the EDAM," and could possibly have zero impact.[462] SCL suggests that although "BPA would prefer to have this included in the market design, it should not be a determinative factor in BPA's DAM decision, as it is unlikely that it will result in meaningful differences in outcomes for BPA.[463] SCL also points out that CAISO is reviewing fast-start pricing for potential adoption in its Price Formation Stakeholder Initiative.[464]

PacifiCorp and PGE comments that "quantitative analysis by CAISO found only marginal increases in payments to resources if fast-start pricing is used in WEIM."[465]

CAISO comments that the price formation aspects are simply ported over from the existing SPP market.[466] Both CAISO and SCL emphasized that CAISO is reviewing fast-start pricing in a price formation enhancements stakeholder process.[467]

Evaluation

Bonneville appreciates the comments of many stakeholders supporting the preference for the price formation features of the Markets+ design, and their emphasis on the importance of this topic to long-term benefits within the footprint. In addition, the Joint Authors highlighted the longer-term benefits of sound price formation, such as price signals to inform the development of new resources and to expand or upgrade transmission facilities.[468] Bonneville agrees with the statements that fair and accurate energy prices are a fundamental aspect of a well-functioning organized market.

Bonneville finds merit in the claims from SCL about how FSP impacts would likely materialize for the Pacific Northwest, due to the impacts of transmission constraints and the fuel mix of the respective regions. However, Bonneville does not agree with the comments submitted by SCL, PacifiCorp and PGE claiming that the impacts of FSP are marginal and therefore should not be a factor in the evaluation of market design. Even if the magnitude of the $/MWh impact is small, the inclusion of FSP in the price formation of marginal LMPs can be impactful overall. Accurate

[461] SCL-040725 at 39.
[462] *Id.* at 39-40.
[463] *Id.* at 39.
[464] *Id.* at 40.
[465] PAC_PGE-040725 at 3.
[466] CAISO-040725 at 11.
[467] SCL-040725 at 40; CAISO-040725 at 11-12.
[468] Joint Authors-040725 at 4.

price formation across the entire footprint is essential and helps to facilitate price signals for transfers within and across market footprints.

Particularly as seams agreements are further developed and hurdle rates between markets are reduced, accurate pricing signals are essential to incentivize economic flow across the west. Additionally, as the fuel-mix may evolve in the future, FSP is an important part of incorporating the entire costs associated with resources that the market uses to meet its operational needs.

As noted by FERC in its Notice of Proposed Rulemaking (NOPR) on FSP in 2016, the implementation of FSP "reforms is important to ensure that rates remain just and reasonable."[469] Most major organized markets have implemented reforms to incorporate FSP in response to the FERC NOPR, with CAISO being an exception. FERC concluded that the exclusion of FSP "may fail to accurately reflect the marginal cost of serving load because fast-start resources are inappropriately prevented from setting prices. Fast-start resources are often dispatched to meet real-time system needs but are often ineligible to set the clearing price . . . ."[470]

From a market operator who has since implemented FSP, Midcontinent ISO (MISO) Independent Market Monitor (IMM) cites that the exclusion of inflexible high-cost resources from price setting creates multiple market inefficiencies, such as the need for uplift payments, the understatement of real-time prices with inefficient incentives for day-ahead scheduling, and poor incentives for imports/exports to displace high-cost peaking resources.[471] MISO IMM also cites the "demonstrated FSP effectiveness in addressing these inefficiencies through increased LMPs when FSRs are economic, reduced uplift, improved DA/RT price convergence, and preserved emergency price signals."[472] Therefore, Bonneville stands by the position that FSP is a critical design element and should be incorporated into its market evaluation.

While SCL, CAISO, and Bonneville in its Draft Policy noted that fast-start pricing is currently under review in CAISO's Price Formation Enhancements initiative, this initiative began in 2022 with scarcity pricing and fast-start pricing as primary issues within its scope. The support for adoption of some of these policy initiatives has faced mixed reactions within the stakeholder process. Without these critical design elements, Bonneville and the entire market footprint are negatively impacted by the lack of FSP, which would provide valuable price signals to the entire footprint and appropriate compensation for flexible generation providing transparent and accurate compensation for resource attributes needed by the market.

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[469] Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, 157 FERC ¶ 61,213, at P 47 (Dec. 15, 2016).
[470] *Id.* at P 37.
[471] CAISO, Price Formation Enhancements: Fast-Start Pricing at 17 (Feb. 13, 2025), *available at* https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Price-Formation-Enhancements-Feb-13-2025.pdf.
[472] *Id.*

As explained in the Draft Policy, while CAISO has considered changes, the absence of FSP reduces costs for California load by failing to provide fair and transparent compensation for flexible generation from fast-start resources. As noted by the Joint Authors, the Markets+ design incorporates consistent fast-start and scarcity pricing programs for the entirety of the market footprint. In contrast, the EDAM design does not currently include scarcity pricing in a manner consistent with other major organized markets. While CAISO argues that Markets+ merely ports over fast-start and scarcity pricing approaches from the SPP Regional Transmission Organization (RTO), these are FERC-approved approaches that are also in place in some form in most other major organized markets.

Decision

Markets+ offers a superior price formation design because it incorporates fast-start pricing and a scarcity pricing approach across the market footprint.

ISSUE 24: Whether Bonneville appropriately considered differences in market power mitigation (MPM) approaches

Draft Policy Proposal

In section 5.2.3. of the Draft Policy, Bonneville outlined the importance of appropriate and accurate monitoring and mitigation for the exercise of market power. Organized markets are structured to encourage competitive and efficient outcomes, and monitoring for the exercise of market power while preventing over-mitigation are an important aspect of a well-designed market. Markets+ utilizes the conduct and impact assessment to evaluate if an offer materially exceeded an established reference level and if that offer would have a material impact on market price, absent mitigation. Bonneville determined that Markets+ would better ensure appropriate and transparent market power mitigation for the entire market footprint because it utilized the conduct and impact assessment while the EDAM design utilizes the pivotal supplier assessment, which is based upon potential exercise of market power, and which Bonneville believes increases the risk of over mitigation and distorts price signals.

Public Comments

Bonneville received several comments on market power mitigation approaches. With respect to MPM design, CAISO suggests that the Markets+ design "simply ports over the existing SPP price formation market design, particularly with respect to market power mitigation"[473] SCL highlights that the CAISO is currently developing changes to its market power mitigation

[473] CAISO-040725 at 11.

mechanism. They also suggest that a portion of the current EDAM market design is similar to the "conduct" portion of the Markets+ market power mitigation design. SCL also expresses "concern that the limited footprint of Markets+ could result in market power issues."[474]

PacifiCorp and PGE comment that "analysis conducted by the CAISO Department of Market Monitoring on market power mitigation showed the amount of resource capacity in WEIM that has bids lowered due to market power mitigation is small."[475]

The Joint Authors assert a different view that the 'conduct and impact' framework in Markets+ is an industry standard design, used in MISO, ISO-NE, and the New York Independent System Operator in addition to SPP's Integrated Marketplace. They explain that "[t]he Conduct and Impact framework lowers the risk of inappropriate mitigation being applied when market power does not actually exist and helps to ensure that flexible resources with dynamic opportunity costs will be available to support reliability when most needed."[476] They contend that in EDAM "mitigation is triggered without examining whether the market participant's bids likely reflect the exercise of market power and without examining whether the participant's bids would materially impact market prices."[477] They argue that as a consequence, "the EDAM approach has the potential to result in more frequent, and overly-broad, mitigation to price levels that can be below a market participant's actual costs."[478]

Powerex and PPC submit similar comments in support of the conduct and impact framework. Powerex states that "the conduct-and-impact framework used in Markets+ focuses on observed behavior rather than theoretical market power potential, reducing over-mitigation risks that can have significant operational consequences for hydro operations."[479] Similarly, "PPC also agrees that the conduct and impact approach to market power mitigation included in Markets+ is superior to the pivotal supplier approach for mitigating market power used in EDAM… The conduct and impact test ensures that prices will only be mitigated if there is both the potential for and execution of market power – meaning that market power is impacting clearing prices. The risk for over mitigation and associated undesired resource dispatch are particularly critical for BPA whose hydro system is facing increasing constraints to meet environmental mandates and other requirements of its system."[480]

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[474] SCL-040725 at 41.
[475] PAC_PGE-040725 at 3-4.
[476] Joint Authors-040725 at 25.
[477] *Id.*
[478] *Id.*
[479] Powerex-040725 at 2.
[480] PPC-040725 at 17.

With respect to the separate matter of a mitigated offer curve methodology for hydro resources, CAISO cites that the Default Energy Bid (DEB) for hydro resources was initially developed with Bonneville engagement and advocacy.[481] CAISO also points to the evolution of its design to remove the price offer cap on DEB, which was supported by Bonneville.[482] SCL suggests that Bonneville has misinterpreted the difference between the EDAM hydro DEB and the Markets+ Seasonal Hydroelectric Offer Curve (SHOC), stating, "it is unclear that there is a material difference between the two DEBs meriting a determination that one is better than the other"[483] and they believe Bonneville would experience better outcomes under the EDAM methodology.

Evaluation

Bonneville appreciates the comments of many stakeholders expressing their views on market power mitigation structures. In particular, the Joint Authors, PPC, and Powerex emphasized the importance of a mitigation approach that focuses on observed behavior, rather than the potential for market power, to reduce over mitigation risks and ensure that flexible resources are available to deploy when needed, while managing the goal of protecting load from inappropriate exercise of market power. Commenters also highlighted that the conduct and impact assessment utilized in Markets+ is a standardized FERC-approved approach utilized in other organized markets while Bonneville would note that CAISO's approach is unique.

Bonneville also prefers the Markets+ conduct and impact methodology, which evaluates if an offer materially exceeded an established reference level and if that offer would have a material impact on market prices, absent mitigation; in contrast the EDAM Pivotal Supplier approach mitigates for potential exercise of market power, which may lead to over-mitigation. As noted by Bonneville in its Draft Policy and by CAISO and SCL in their comments, as part of the CAISO's Price Formation Enhancements initiative, CAISO is considering changes to its market power mitigation assessment, recognizing that the pivotal supplier assessment structured on BAA-level mitigation should be reviewed and potentially modified by the stakeholder group. In response to claims from SCL that the "WEIM/EDAM MPM already has a mechanism that functions like the 'conduct' portion of the conduct and impact test"[484]

Bonneville does not view the use of the competitive LMP as equivalent to a robust conduct and impact assessment. Further, neither the CAISO comments nor the materials cited claim that their design mimics the conduct portion of the assessment and CAISO's own process has included an open discussion of whether they should adopt the conduct and impact assessment, directly

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481 CAISO-040725 at 12.
482 CAISO-040725 at 12.
483 SCL-040725 at 40.
484 SCL-040725 at 41.

implying that the current methodology is not equivalent. Since the Price Enhancements initiative launched in 2022, Bonneville has submitted comments in support of considering a conduct and impact assessment throughout the process.[485] While Bonneville continues to engage in the CAISO initiatives on improving aspects of the market power mitigation design, there seems to be mixed support for making enhancements to MPM and the likelihood of change seems uncertain. In a day-ahead market where significantly more resources and loads are subject to market awards, MPM design elements are critical aspects to the overall market design.

Bonneville does not agree with the comment submitted by SCL that the "limited footprint" of Markets+ would increase the potential exposure to the exercise of market power.[486] Regardless of footprint, the methodologies deployed to mitigate and monitor market power, as well as the underlying market design should incentivize robust and competitive participation. Approaches that reduce competition are problematic because competition should be the key driver of reducing market power, rather than the size of the footprint. The SPP Market Monitoring Unit (MMU) will be responsible for monitoring the entire footprint for the potential exercise and mitigation of market power should it occur.

Addressing comments submitted by PacifiCorp and PGE, Bonneville does not disagree with the underlying analysis that the commenters cite from the Department of Market Monitoring (DMM). While Bonneville finds the analysis from DMM to be informative, the participation of resources and loads in WEIM is quite limited, particularly for Bonneville. In a day-ahead market, the volume of participation is significantly higher and therefore it is difficult to extrapolate that the behavior and analysis of WEIM can be easily extended to a potential day-ahead market footprint, with a much higher degree of resource participation. Further, Bonneville notes that even a small number of mitigated bids can be inappropriate if the effect of the MPM approach limits competition or if bids are mitigated below a given generator's actual costs.

As a separate matter, both CAISO and SCL submitted comments regarding the similarities between the two mitigated offer curve calculations used for hydro in EDAM and Markets+, the DEB and SHOC respectively. Bonneville agrees with the commenters that these methodologies are far more similar than dissimilar. In the Draft Policy Bonneville states, "for storage hydro, the Markets+ and EDAM are very similar, as the Markets+ design was built upon the approach utilized in WEIM." CAISO acknowledges that Bonneville was heavily engaged in the development of the DEB, a several-years long process to recognize the opportunity cost-based

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[485] BPA's comments are available on CAISO's stakeholder comments website at https://stakeholdercenter.caiso.com/Comments/AllComments/6ac34d7d-0fc1-4a9e-b498-3592f3679999 (Comments on Issue paper: Price formation enhancements (Aug. 9, 2022)) and https://stakeholdercenter.caiso.com/Comments/AllComments/4606ae2b-2d5d-4c57-a73f-e5fdc099f3e4 (Comments on Balancing Authority Area-level Market Power Mitigation working group discussions (Dec. 13, 2024)).

[486] SCL-040725 at 41.

nature of storage hydro, where Bonneville faced significant opposition and challenges from California stakeholders throughout.

Bonneville continues to support the CAISO hydro DEB over other available DEB options. However, Bonneville and other commenters' formal comments consistently emphasized that attempts to approximate opportunity costs are flawed because of the various power and non-power objectives faced by hydro operators. When paired with a mitigation approach such as pivotal supplier assessment, the EDAM approach presents significant risk of over-mitigation. The stakeholders of Markets+ were comfortable using the DEB as the starting point, due to the robust deliberation that went into the initial development of the DEB at CAISO.

Through the Markets+ stakeholder process, the MMU of SPP advocated for a seasonal aspect to be added to the storage calculation for the hydro offer curve. Bonneville recognizes that there is a seasonal aspect to the storage duration of certain hydro projects within the west and is supportive of adopting modifications to existing designs. Ultimately, both DEB and SHOC are imperfect proxies for Bonneville's opportunity costs, which as noted can only be accurately determined internally due to a broad array of system considerations, limitations, and expertise. But Bonneville believes that for both resources and loads, the entire footprint benefits from mitigated offer curves that attempt to be as accurate as possible. Bonneville supports the SHOC method for its slight modifications to the DEB. As these two calculations only differ in one small component, they are not a key driver of stated preference for Markets+ in the consideration of market power mitigation.

Decision

Bonneville maintains its policy position that Markets+ offers superior market power mitigation methodologies because it deploys the conduct and impact assessment. In addition, Bonneville maintains its preference for the seasonal storage adjustment in the Markets+ SHOC methodology.

5.2.4. Congestion Modeling and Congestion Rent

ISSUE 25: Whether Bonneville appropriately considered congestion rent design

Draft Policy Proposal

Congestion rent design is discussed in Section 5.2.4 of the Draft Policy.

Public Comments

Many commenters agree with Bonneville's assessment and conclusion that Markets+ has a more robust congestion rent design. PPC supports "BPA's conclusion that Markets+ offers a preferred approach to allocating transmission congestion."[487] According to PPC, the Markets+ design "provides customers with a better opportunity to hedge their cost risk on BPA's system," and "creates a strong incentive for continued investment in BPA's long-term transmission service."[488]

Powerex states that the EDAM design "potentially shift[s] significant economic value between BAAs and their customers inappropriately."[489]

Snohomish also agrees that the Markets+ congestion rent design is superior, stating that it "shares concerns raised by many parties, including Bonneville, about the EDAM approach."[490] Similarly, "NRU agrees with Bonneville's stated preference for the Markets+ constraint-level design, which more accurately recognized the topology of the footprint and is better aligned with Bonneville's current modeling practices."[491]NIPPC states that it "agrees with BPA that the Markets+ design is superior to EDAM,"[492] while NIPPC noting that the CAISO is working on addressing issues with the EDAM's congestion rent design.

AWEC "is also concerned that the current EDAM congestion policies inappropriately limit benefits to customers by allocating congestion revenues to CAISO's BAA," and "will also stifle incentives to make cost-effective investments in transmission."[493] AWEC concludes that "Markets+ does not suffer the same design flaws and instead approaches the allocation of congestion revenues proportionately to transmission rights holders, thus ensuring that incentives remain properly aligned."[494]

The Joint Authors state that "none of the production[] cost models to date appear to reflect the significant differences in how congestion revenues will be allocated among participants" and that "[t]he magnitude of the value at issue is potentially very large according to some estimates, with the potential to significantly alter the net benefits being projected."[495] The Joint Authors also highlight the importance of the "stakeholder-driven approach to the initial design of Markets+" in developing a superior congestion rent design.[496]

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[487] PPC-040725 at 17.
[488] *Id.*
[489] Powerex-040725 at 3.
[490] Snohomish-040725 at 4.
[491] NRU-040725 at 4.
[492] NIPPC-040725 at 77.
[493] AWEC-040725 at 2.
[494] *Id.*
[495] Joint Authors-040725 at 5.
[496] *Id.*

Several other commenters also express general agreement with Bonneville's assessment.[497]

SCL acknowledges that the CAISO is currently working on addressing the concern about the "potential for exposure to congestion that occurs elsewhere within the EDAM footprint without a means to adequately hedge or recover revenue."[498] SCL also questions whether "the Markets+ constraint-level allocation will provide better protection to load."[499] SCL states that "the congestion revenue will not be allocated just to the load that bears the cost of congestion" but "will be spread across *all of the rights sold for that constraint*."[500] According to SCL, because "congestion revenue will be allocated to an entity based on its share of the total MW of transmission rights across that constraint" and "the total quantity of congestion rent distributed will be based on MW of market flow . . . there is potential that constraints that are likely to bind have sold more MW of rights than are able to flow." SCL states that "it is likely that not all transmission rights are simultaneously feasible and, thus, a rights holder across a constrained path will only receive a fraction of the per MWh congestion payment."[501] SCL ultimately requests analysis on "whether the Markets+ congestion allocation approach could create additional challenges for BPA's already-lengthy queue by creating economic incentives to procure or hold on to long term transmission rights on lucrative paths that are important for serving load."[502]

PG&E states that Bonneville's issue with EDAM's congestion rent design will be solved by joining EDAM because the allocation problem is created by Market seams. As an example, PG&E points to the 2024 MLK weekend, where, according to PG&E, 94% of congestion rent flowed to California. PG&E states that the "problem arises because the CAISO market does not model nor control transmission constraints outside of its market" and results "when a flowgate is managed at a market seam." PG&E concludes that joining EDAM will eliminate this seam and solve the congestion rent concerns.[503]

Evaluation

As described in the Policy, EDAM currently allocates congestion revenues to the participating "BA where the binding constraint is modeled."[504] This design could expose customers in one BAA to congestion in a neighboring BAA "without the means to adequately hedge or recover

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[497] *See* WPUDA-031225 at 3; Big Bend-040725 at 1; CRPUD-040725 at 1; Hood River-040425 at 1; Lincoln-040425 at 1; Modern-040425 at 1; Pacific-040725 at 1; IFP-040725 at 2; Cowlitz-040725 at 1.
[498] SCL-040725 at 43.
[499] *Id.*
[500] *Id.*
[501] *Id.*
[502] *Id.* at 44.
[503] PG&E-040725 at 2.
[504] Policy at 50.

revenue from the costs incurred by load."[505] In addition, this requires the EDAM entity BA to suballocate congestion revenues directly to transmission customers based on the individual EDAM entity's tariff, which "can present undue complexity for customers by producing a wide set of outcomes depending on the tariff or tariffs to which a customer is subject."[506]

CAISO is currently evaluating limited changes to the congestion rent allocation to minimize the unintended impacts of parallel flows. However, the modifications are limited in scope, with the allocation being BAA centric with a "use-it" or "lose it" incentive centering congestion allocation to schedules rather than transmission rights. Bonneville does not expect the changes CAISO proposes to affect Bonneville's analysis, as it maintains the existing allocation of congestion revenue to the BA rather than directly to transmission rights holders. Bonneville has updated the Policy to include this information.[507]

Bonneville maintains its position that the congestion rent design of Markets+ is more robust than the EDAM design. Markets+ "evaluates allocation across the entire footprint, specifically the rights associated with individual constraints."[508] The Markets+ congestion rent design "better recognizes the topology of the market footprint and directly aligns with how Bonneville models and manages transmission constraints."[509] In addition, the Markets+ direct allocation of congestion rents to transmission rights holders based on transmission rights, not schedules, incentivizes continued purchase of long-term firm transmission. A majority of commenters expressed support for Bonneville's analysis and conclusion.

SCL's comments do not change Bonneville's position. SCL's argument that Markets+ may not provide better protection for load is dependent on the individual EDAM BA's decision on how to allocate congestion revenue it receives. Under the proposed allocations of entities that have submitted tariff amendments with FERC to participate in EDAM, the receipt of congestion revenue is dependent on loads self-scheduling, which may put loads in a worse position because self-scheduling removes loads from market optimization.[510] While an EDAM BA can certainly create an allocation that may skew towards protecting loads, this underscores Bonneville's concern that EDAM's congestion rent design can "[produce] a wide set of outcomes depending on the tariff or tariffs to which a customer is subject."[511]

SCL's argument that the Markets+ allocation based on transmission rights may reduce congestion revenue received on oversold lines is also unconvincing. While SCL is accurate that

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[505] *Id.* at 51.
[506] *Id.* at 50.
[507] *Id.* at 48-52.
[508] *Id.* at 48.
[509] *Id.*
[510] *See, e.g., Portland Gen. Elec. Co.*, FERC Docket No. ER-25-1868-000, Transmittal Letter at 17 (Apr. 3, 2025); *PacifiCorp*, FERC Docket No. ER-25-951-000, Transmittal Letter at 18-19 (Jan. 16, 2025).
[511] Policy at 50.

congestion revenues will be proportionally reduced based on the amount of transmission rights sold on a particular path, the tradeoff is that there is no incentive for requiring self-scheduling for receipt of congestion revenues. This leads to greater market benefits as the market will optimize a greater volume of transactions.

SCL also expresses concern that the Markets+ congestion rent design will incentivize the purchase of long-term transmission and may exacerbate Bonneville's "already-lengthy" transmission queue. Issues with the transmission service queue are beyond the scope of this ROD and are being addressed in a separate setting. That said, Bonneville does not view SCL's concern as a problem. Incentivizing the purchase of long-term transmission will help maintain transmission revenues and keep transmission rates lower for all customers. Moreover, Bonneville is an open access transmission provider and must sell transmission under its tariff for existing and future transmission capacity, regardless of market decision. Bonneville will not conduct any additional analysis on this issue as requested by SCL. Bonneville posts transmission information on the Open Access Same-time Information System (OASIS) that customers can use to better inform their decisions.

PG&E points to the 2024 MLK event to argue that eliminating market seams will solve Bonneville's issues with EDAM's congestion rent design. This argument is also unconvincing. While the elimination of market seams may lead to more easily managed outcomes between markets, it does not inherently guarantee equitable outcomes will be achieved. Additionally, these seams can be mitigated through coordinated agreements. In any event, it does not change Bonneville's position that the Markets+ congestion rent design is the better option.

Decision

The Markets+ congestion rent design is more robust than the EDAM design for the reasons explained in its evaluation above and as described in Section 5.2.4 of the Final Policy.

5.2.5. Greenhouse Gas Accounting

ISSUE 26: Whether there has been enough information to evaluate customer requests pertaining to the Markets+ GHG design, compared to the EDAM GHG design

Draft Policy Position

In section 5.2.5 of the Draft Policy, Bonneville concludes that there is enough information available for Bonneville to determine that the Markets+ design is superior to the EDAM design in meeting the concerns expressed by Bonneville customers.

Public Comments

Many commentors mention the importance to utilities across the region, particularly those in Washington, of the day-ahead market's GHG accounting approach and ability to maintain the low-carbon attributes of the federal system.[512]

Many commentors express support for the Markets+ GHG design.[513] Commentors also share support for the Markets+ stakeholder process. WPAG states, "SPP's stakeholder process provides superior flexibility, allowing participants an opportunity to revise the GHG accounting design to account for changes in the GHG reporting landscape."[514] Snohomish comments that it "appreciates the collaborative effort in the Markets+ GHG Task Force by market participants and regulators across a variety of states to develop an out-of-market GHG tracking and reporting framework that is compatible with a variety of state programs with very different requirements (including CETA)."[515]

Several commentors agree with Bonneville's conclusion that the Markets+ GHG design provides superior assurance compared to EDAM and it will better ensure that customers can continue to claim the low-carbon attributes of the federal system.[516] The Joint Authors also state that the Markets+ GHG design provides a more equitable approach to meeting the needs of market participants generally.[517] These commentors collectively recognize several aspects of the Markets+ GHG design that led to their conclusion, namely that the Markets+ GHG design: 1) respects existing contractual commitments through Type 1A designation;[518] 2) provides autonomy and flexibility for market participants to determine what supply is available or not available for attribution to a GHG pricing zone by employing the threshold approach;[519] 3) provides improved validation and price transparency for attribution to the GHG pricing zone;[520] 4) reduces leakage and cost shifts to utilities not subject to a pricing program;[521] 5) provides reporting and tracking that will support the needs of utilities subject to non-pricing emission

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[512] PPC-040725 at 18-19; Puget-040125 at 1; WPAG-040725 at 3; SCL-040725 at 44; AWEC-040725 at 2; Snohomish-040725 at 5; Big Bend-040725 at 1; Mason-040725 at 1-2; WPUDA-031225 at 3-4; NRU-040725 at 1-2.
[513] Big Bend-040725 at 1; CRPUD-040725 at 1; Hood River-040425 at 2; Lincoln-040425 at 1; Mason-040725 at 1-2, Modern-040425 at 1; Pacific-040725 at 1; Cowlitz-040725 at 1; WPAG-040725 at 3; NRU-040725 at 2; Joint Authors-040725 at 6; Powerex-040725 at 3; PPC-040725 at 18-19; Snohomish-040725 at 5; NRU-040725 at 4; WPUDA-031225 at 3-4.
[514] WPAG-040725 at 4.
[515] Snohomish-040725 at 5.
[516] Powerex-040725 at 3; Joint Authors-040725 at 5-6; PPC-040725 at 18; Snohomish-040725 at 5.
[517] Joint Authors-040725 at 5-6.
[518] Powerex-040725 at 3; Joint Authors-040725 at 5-6; PPC-040725 at 8; Snohomish-040725 at 5.
[519] Powerex-040725 at 3; Joint Authors-040725 at 6, 36-37; PPC-040725 at 8.
[520] Powerex-040725 at 3; Joint Authors-040725 at 6, 37.
[521] Joint Authors-040725 at 6, 34-38.

reduction requirements and voluntary utility goals;[522] and 6) enables unspecified resource attribution to the GHG pricing zone when economic.[523]

NIPCC acknowledges that the Markets+ GHG design provides a stronger GHG accounting framework, but stated it anticipates the EDAM design will continue to evolve and improve.[524]

In contrast to others, SCL and the State Agencies disagree that there were meaningful differences between Markets+ and EDAM GHG design. SCL comments that "[w]hile there may be some differences in the design of these elements, it is not meaningful to support choosing a DAM that will result in poor economic and reliability outcomes for its customers. In the end, this is not a measurable difference."[525] SCL states "it was unclear if BPA believes the CAISO GHG approach does not meet BPA's baseline needs (i.e., would need to change for BPA to join EDAM), or if BPA simply prefers the Markets+ approach.")[526]SCL "asks that BPA provide additional information on BPA's position on the GHG accounting mechanisms for both markets, as well as BPA's baseline needs."[527] The State Agencies comment that they "disagree with BPA's conclusion that differences in Markets+ and EDAM GHG design elements will obviously result in markedly worse outcomes for BPA's Washington and Oregon customers under EDAM."[528] And they go on to say they "believe that when the full design of EDAM is considered, including the ability to indicate committed capacity, both Markets+ and EDAM provide significant ability to reflect contractual commitments to Washington and enable attribution of low-cost clean resources."[529]

SCL and the State Agencies also express confidence in the CAISO stakeholder process. SCL states that Bonneville, in characterizing CAISO's GHG accounting design, "not only misrepresents CAISO's relationship with stakeholders and state policy, but it also ignores history."[530] SCL further states that "that CAISO is responsive to our needs, actively engaged with and collaborating with the regulating agencies, and available for assistance as we learn to navigate these nascent programs. City Light and Washington policies have not been treated on a lesser basis."[531] The State Agencies comment that "BPA appears to discount efforts within CAISO to respond to stakeholder inputs on GHG design."[532] The State Agencies are "confident

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[522] Joint Authors-040725 at 6, 34-38; Snohomish-040725 at 5.
[523] Joint Authors-040725 at 6, 37.
[524] NIPPC-040725 at 5.
[525] SCL-040725 at 51.
[526] *Id.* at 9.
[527] *Id.*
[528] OR-WA State Agencies-040725 at 9.
[529] *Id.*
[530] SCL-040725 at 17.
[531] *Id.* at 18.
[532] OR-WA State Agencies-040725 at 8.

both market operators will develop a GHG tracking and reporting approach that meets the initial needs of Oregon and Washington's non-pricing clean energy programs."[533]

Evaluation

Bonneville appreciates the commenters' submitting their assessments of the Markets+ GHG design as compared to the EDAM GHG design. Bonneville recognizes the importance to utilities across the region, particularly those in Washington, of the day-ahead market's GHG accounting approach and ability to maintain the low-carbon attributes of the federal system.[534]

Bonneville assessed aspects of the Markets+ GHG design where there were meaningful differences from EDAM that would impact Bonneville's GHG principle. Bonneville agrees there are other aspects of the Markets+ GHG design that also broadly support market participants' needs, as the commentors (specifically the Joint Authors) point out.[535]

In response to SCL's and the State Agencies' comments, Bonneville thoroughly assessed meaningful differences between the EDAM and Markets+ GHG designs in relation to how those differences would impact the ability of its customers to continue to claim the low-carbon attributes of the federal system. As discussed in Issue #27, Bonneville had enough information available to evaluate and determine that Markets+ better meets its GHG evaluation principle.[536]

SCL and the State Agencies also expressed that they have confidence in the CAISO stakeholder design and SCL made various representations about its experience working with CAISO.[537] Bonneville understands that this has been these commenters' experience in working with CAISO. As described above in Issues #11-17 (Governance), the CAISO governance structure has influenced the confidence Bonneville has in CAISO's stakeholder processes and whether they result in outcomes that work fairly and equitably for all participants and states regarading GHG programs.

Decision

The Markets+ design for GHG accounting provides superior assurance that Bonneville's customers would continue to claim the low-carbon attributes of the federal system.

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[533] *Id.* at 9.
[534] PPC-040725 at 18-19; Puget-040125 at 1; WPAG-040725 at 3; SCL-040725 at 44; AWEC-040725 at 2; Snohomish-040725 at 5; Big Bend-040725 at 1; Mason-040725 at 1-2; WPUDA-031225 at 3-4; NRU-040725 at 1-2.
[535] Joint Authors-040725 at 5-6, 34-38.
[536] *See* Policy § 5.2.5; *see also* Issues 27, 28, and 29 below (discussing GHG issues on committed capacity, the EDAM counterfactual, and the EDAM net export constraint).
[537] SCL-040725 at 51; OR-WA State Agencies-040725 at 8.

ISSUE 27: Whether Bonneville properly considered EDAM's "committed capacity" feature in its assessment of GHG design

Draft Policy Position

Bonneville discussed CAISO's committed capacity feature in section 5.2.5.1.1 of the Draft Policy, concluding that feature is more akin to Markets+ Type 1B and that feature does not recognize contractual commitments in an equivalent manner to Markets+ Type 1A.

Public Comments

CAISO, SCL, and the State Agencies comment that Bonneville did not consider or understand how EDAM's "committed capacity" feature would provide attribution of the federal system to the Washington GHG zone.[538] They point out that EDAM allows the participant to identify contracted resources (committed capacity) for attribution to the GHG zone, and that committed capacity is not included as part of the baseline run (counterfactual). CAISO compares EDAM's committed capacity feature to Markets+ Type 1A, stating the committed capacity feature "would allow Bonneville's preference customers to claim the clean attributes of the FCRPS."[539] CAISO also states that "if the [committed capacity] resource bid is not economic to serve load in the GHG regulation area (based on its energy bid plus a GHG adder), it still may be economic (based on its energy-only bid) to serve the non-GHG regulation area (i.e., the rest of the market footprint)."[540] CAISO emphasizes in its comments that "Bonneville, under the EDAM design, is in full control of how and when it seeks to attribute the contracted FCRPS to the Washington GHG regulation area based on how it bids in the market."[541]

CAISO and SCL state that for both Markets+ Type 1A and EDAM committed capacity the resources must be economic to be dispatched and attributed.[542] CAISO and SCL state that the Markets+ Type 1A resource, if not economic [presumably to the GHG zone] would not be attributed to Washington and could not be dispatched to serve load in the rest of the market.[543] CAISO states this would have the effect of "…reducing market efficiency and the ability of Bonneville to otherwise derive value for that generation."[544]

SCL and the State Agencies then question Bonneville's assessment that, without a Markets+ Type 1A equivalent, EDAM could result in the dispatch of fossil fuel generation within

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538 CAISO-040725 at 10; SCL- 040725 at 44-45; OR-WA State Agencies-040725 at 9.
539 CAISO-040725 at 8.
540 *Id.* at 9.
541 Id.
542 *Id.* at 9-10; SCL-040725 at 44-45.
543 CAISO-040725 at 9; SCL-040725 at 44.
544 CAISO-040725 at 9.

Washington while federal system power is dispatched but not attributed to Washington. The State Agencies state they "do not believe this is an obvious or even likely outcome under EDAM. If BPA indicates committed capacity to Washington and BPA power is cheaper than in-state fossil resources, it seems likely that economic dispatch would result in dispatch and attribution of the available cheaper BPA resources to Washington."[545] SCL states that "if BPA told CAISO what resources were committed capacity to serve Washington, those contracts would be excluded from the counterfactual and be eligible to be attributed to serve Washington, if economic."[546]

The commentors ask Bonneville to reassess its evaluation of the EDAM GHG design in light of this information.

Evaluation

Bonneville understood and considered the committed capacity aspect of the EDAM design.[547] To be clear, Bonneville understands committed capacity is excluded from the counterfactual run and Bonneville has updated its policy to clarify.[548] Bonneville also understands the net transfer constraint does not apply to committed capacity nor apply when the BAA is at least partially located in the GHG zone. With that in mind, Bonneville considered the following points as it evaluated CAISO's committed capacity concept.

First, CAISO has not elaborated on the committed capacity concept. It is not mentioned in CAISO's tariff and only briefly referred to in CAISO's final EDAM policy document. CAISO has no Business Practice Manual posted for it at the time of publication of this policy. However, based on the information available, Bonneville was able to consider important differences between Markets+ Type 1A and EDAM's committed capacity.

Second, CAISO argues that if a "'Type 1A' resource is not economic in the market, it would not be attributed to Washington as a GHG regulation area and could not be dispatched efficiently to serve load in the rest of the Markets+ footprint, thus reducing market efficiency and the ability of Bonneville to otherwise derive value for that generation."[549] To the contrary, Markets+ Type 1A resources will be dispatched when its bid offer, including GHG adder, is economic to meet load in the market footprint. If dispatched, it will *always* be attributed to the GHG zone. This certainty of attribution is important to Bonneville. The Type 1A attribution does not preclude the GHG

545 OR-WA State Agencies-040725 at 8.
546 SCL-040725 at 44.
547 Draft Policy § 5.2.5.1.1.
548 Policy § 5.2.5.1.2.
549 CAISO-040725 at 9.

zone from exporting to the rest of the market. In short, Markets+ is still selecting an efficient market outcome and Bonneville will still derive value for the Type 1A resource.

Third, Bonneville understands that the EDAM committed capacity feature would allow Bonneville to identify contracted amounts to its customers in Washington. However, per CAISO's statement in its comment: "if the resource bid is not economic to serve load in the GHG regulation area (based on its energy bid plus a GHG adder), it still may be economic (based on its energy-only bid) to serve the non-GHG regulation area (*i.e.*, the rest of the market footprint)."[550] In other words, the EDAM market run (the integrated forward market (IFM)) will simultaneously seek out the most economic solution for the market, and in doing so may attribute the committed capacity to the Washington GHG zone or may determine the economic solution is for the resource to serve the non-GHG area. The primary difference between Type 1A and Type 1B in the Markets+ design is whether the megawatts can be economically dispatched without being attributed to the GHG pricing zone. As Bonneville previously explained, EDAM committed capacity is most similar to the Markets+ Type 1B resource, which may be attributed to the GHG zone (based on its energy bid plus GHG adder), or may meet general market load (based on its energy-only bid), resulting in the most economic solution for the entire market footprint, including the GHG zone. By virtue of being able to be economically dispatched without being attributed to the GHG pricing zone, EDAM's committed capacity concept is not akin to Type 1A.

At most, CAISO's statement in its comment appears to imply some sort of preference for committed capacity to be prioritized as attributed to the GHG zone in the IFM, but there is no CAISO documentation on committed capacity that supports this assertion. Nor is there any documentation that assures the committed capacity, if economic to meet any load in the market, is assured to be attributed to the GHG zone (like Markets+ Type 1A). Thus, there is no information available to enable further assessment of treatment of committed capacity.

Finally, the committed capacity feature affords only limited control to Bonneville. CAISO emphasizes: "Bonneville, under the EDAM design, is in full control of how and when it seeks to attribute the contracted FCRPS to the Washington GHG regulation area based on how it bids in the market."[551] However, this control is limited to whether Bonneville seeks to enable committed capacity to be attributed to Washington (when and the maximum amount). As evidenced by CAISO's comment that committed capacity " . . . still may be economic (based on its energy-only bid) to serve the non-GHG regulation area (i.e., the rest of the market footprint),"[552] Bonneville has no control over whether that committed capacity is then determined by the IFM to be attributed to Washington or whether it is attributed to another GHG zone or the non-GHG zone. The IFM will make that determination based on the most economic outcome for the entire

[550] *Id.*
[551] *Id.*
[552] *Id.*

market, including the GHG zone(s). Similar to Bonneville's assessment, the Joint Authors recognized that CAISO's committed capacity feature would not provide the amount of control and autonomy that Markets+ would provide, they stated: "Markets+ provides more autonomy over how market participants make their supply available to the market, and more flexibility to identify which supply is available or not available to be attributed to a GHG zone."[553]

Related to Bonneville's committed capacity discussion, some commenters expressed concern with Bonneville's statement that the CAISO design could enable "dispatch of fossil fuel generation within Washington while less expensive Bonneville power could be dispatched but not attributed to Washington." These commenters appear to misunderstand the point Bonneville was making and misunderstand the importance of the Markets+ Type 1A concept and why Bonneville determined the Type 1A concept is a critical feature. Absent the Type 1A concept, under either market design, clean or low-carbon resources like the federal system may not always be attributed to Washington. Bonneville needs the federal system to always be attributed to Washington (if part of the economic solution for the market) to avoid financial implications in high price/high load times.

While commentors note the federal system, given its low-carbon attributes, will often be part of the economic solution for and thus attributed to the GHG zone, during high price/high load times this will not always be the case. This is because at such times, most, if not all, generation—including fossil fuel resources—located in Washington and across the market will be dispatched to meet loads. The market solutions will first assume resources located inside the GHG zone meet loads in the GHG zone before attributing resources considered external to the zone. Thus, the federal system, which is external to the Washington GHG zone, may not end up being attributed to Washington. In such times, Bonneville will pay the higher cost of energy (energy + GHG price) for the load in its BAA in Washington. However, if the federal system is not attributed to the Washington GHG zone, Bonneville will not recover that GHG cost in its award (energy only)—thereby increasing costs for Bonneville and its ratepayers due to both the state GHG pricing program and the market design.

The Markets+ Type 1A feature avoids this situation. As long as the federal system is dispatched, Type 1A ensures it is attributed to Washington. Bonneville would still pay the higher cost (energy + GHG price) for its loads in Washington, but Bonneville's Type 1A resources would also be awarded the higher price (energy + GHG price). CAISO's design has no feature that is comparable to this, nor one that provides certainty that Bonneville would recover the full cost of its resources and GHG adder.

Similar to Bonneville, various commenters recognize the certainty of attribution that Markets+ could provide, and the importance of that feature. The Joint Authors sum it up as follows:

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[553] Joint Authors-040725 at 6.

"Markets+ will enable market participants to deliver clean energy in a manner that respects existing contractual commitments and provides critical assurance that Bonneville can continue to attribute power from the federal system to its Washington customers."[554] Powerex states: "Powerex agrees with Bonneville's analysis that Markets+ offers superior Greenhouse Gas (GHG) attribution mechanisms—particularly the 'Type 1A' contract-based attribution and surplus threshold modeling. These features protect the integrity of Bonneville's low-carbon federal power in Washington and Oregon compliance frameworks, ensuring Bonneville customers receive expected benefits from clean supply."[555] Likewise, Snohomish comments that it "agrees with Bonneville that relative to the EDAM design, the Markets+ approach improves Bonneville's ability to ensure that its customers both inside and outside Washington are able to claim the low-carbon attributes of their federal power purchases. The 'Type 1A' option in Markets+ provides assurance that Snohomish will receive the benefits of the low carbon attributes. . . ."[556]

Decision

Markets+ provides better certainty of attribution because of the Type 1A feature as described in Final Policy section 5.2.5.1.1. Commenters neither provide definitive information, nor show that Bonneville missed any relevant facts, to support the suggestion of an error in Bonneville's analysis that EDAM's committed capacity feature merely provides treatment similar to Markets+ Type 1B feature (and not similar to Type 1A).

ISSUE 28: Whether Bonneville properly considered EDAM's counterfactual baseline run feature in its assessment of GHG design

Draft Policy Position

In section 5.2.5.1 of the Draft Policy, Bonneville compared and contrasted the GHG baseline runs between Markets+ (the "threshold" run) and with EDAM (the "counterfactual" run). Bonneville concludes that the Markets+ threshold run better recognizes Bonneville's load obligations in determining energy eligible for attribution, thus limiting the risk that energy contracted to other utilities will be attributed to states with GHG pricing programs.

Public Comments

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[554] *Id*.
[555] Powerex-040725 at 3.
[556] Snohomish-040725 at 5.

CAISO comments that Bonneville "does not accurately describe the purpose and function of the EDAM GHG counterfactual market run."[557] CAISO clarifies that "the counterfactual market run stacks resources to find the most cost efficient way to serve all load obligations within and outside of a GHG regulation area (i.e., it does not focus only on load outside of GHG regulation area), absent GHG state policy."[558] CAISO continues, "[u]nder the EDAM design, the counterfactual market run stacks resources to find the most cost efficient way to serve all load obligations within and outside of a GHG regulation area (i.e., it does not focus only on load outside of GHG regulation area), absent GHG state policy."[559] CAISO further states "the EDAM design allows for committed capacity (i.e., contracted capacity to the GHG regulation area) to be excluded from the GHG counterfactual run so that these are considered in the bid stack that is available for attribution to the GHG regulation area . . . ."[560]

Evaluation

Bonneville appreciates CAISO's clarification that the EDAM GHG counterfactual run stacks resources to find the most cost-efficient way to serve all load obligations within and outside of a GHG regulation area (i.e., it does not focus only on load outside of GHG regulation area), absent GHG state policy. Bonneville has updated its policy to incorporate this clarification.[561] However, CAISO appears to misunderstand Bonneville's concern with the counterfactual run, which has nothing to do with committed capacity.

Bonneville discusses the counterfactual run in comparison to the Markets+ threshold run, not in reference to Markets+ Type 1A/EDAM committed capacity. Thus, CAISO's comments do not address Bonneville's main point regarding the differences in the baseline runs for the market: that the correct measure for determining if a resource (or system of resources, in Bonneville's case) should be eligible for attribution (if not contractually committed to load in the state) is whether the resource has energy that is surplus to any load obligations for an individual entity. The Markets+ threshold run does this, the EDAM counterfactual run does not.

Specifically, these baseline runs (EDAM counterfactual, Markets+ threshold) seek to limit attribution to a GHG zone to reduce leakage/secondary dispatch. In that way, the baseline run establishes what amounts from a resource (committed capacity aside) are eligible for attribution to a GHG zone.

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557 CAISO-040725 at 10.
558 *Id.*
559 *Id.*
560 *Id.*
561 *See* Policy § 5.2.5.1.2.

The EDAM counterfactual run goes about this by taking a broad look at resources across the market footprint to establish eligibility. As CAISO explained in its EDAM filing, the EDAM counterfactual will "*approximate how a balancing area outside the GHG regulation areas will meet its own load with its internal generation as well as supply from other balancing areas outside of the GHG regulation area.* The goal of the GHG reference pass is to reflect how supply resources can optimally serve demand in the EDAM footprint without net imports into the GHG regulation areas and the associated cost of compliance with GHG regulation."[562]

The practical result of this, as Bonneville discusses in the Policy, is that the amount of eligible attribution is determined by establishing whether the resource was dispatched in the counterfactual to meet load *in the EDAM footprint without net imports into the GHG regulation area(s)* rather than a comparison to the *individual entity's* load obligations.[563] Hence, EDAM's approach looks at what resource amounts are surplus to the needs of the demand in the EDAM footprint without net imports into the GHG regulation area(s). Bonneville maintains this is an inappropriate measure of whether a resource should be eligible for attribution to the GHG zone.

In contrast, when Markets+ designed its threshold run, it evaluated whether the run should be conducted on an individual basis, BAA basis, or market-wide basis. Ultimately, Markets+ determined the individual basis was the most appropriate measure.[564]

Bonneville prefers the individual approach that Markets+ takes for its threshold run. It allows for more flexibility for the resource owner/operator, potentially increases availability of imports to the GHG zone, and enables individual states to set limits around what qualifies as surplus for the state program in order to customize leakage considerations for their individual state. CAISO's latest comments do not change this assessment.

Decision

Bonneville determines that the Markets+ threshold run (which is conducted on an individual entity basis) is one aspect of the Markets+ GHG design that provides greater assurance than the EDAM GHG design (with its counterfactual run conducted on a market-wide basis) that Bonneville's customers will be able to maintain the low-carbon attributes of the federal system.

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562 *CAISO*, FERC Docket No. ER23-2686, Transmittal Letter at 163-64 (Aug. 22, 2023) (emphasis added).
563 *See* Policy § 5.2.5.1.2.
564 *See* SPP, MGHGTF Type 2 Specified Source Import Supplemental Aug 1, 2023 meeting materials (PowerPoint presentation) (July 27, 2023) *available at* https://www.spp.org/Documents/69801/MGHGTF%20Meeting%20Materials%2020230801.zip ("SPP Type 2 Specified Source Import Supplemental presentation").

ISSUE 29: Whether Bonneville properly considered EDAM's "net export constraint" feature in its assessment of GHG design

Draft Policy Position

In section 5.2.5.1.2 of the Draft Policy, Bonneville stated concern with the EDAM net export constraint, stating that that "the BAA is also not the appropriate measure of whether an individual resource has surplus energy available to meet load in a GHG pricing area."[565]

Public Comments

CAISO comments that Bonneville does not acknowledge that the EDAM GHG net export constraint does not limit the ability for committed capacity to be attributed to a GHG zone. Thus, CAISO contends that Bonneville's concern with the GHG net export constraint can be addressed by identifying the FCRPS as contracted to the GHG zone.

Regarding the net export constraint, CAISO comments that "Bonneville's description fails to acknowledge that this constraint explicitly does not apply to committed capacity (contracted generation) and attribution of this committed capacity is not precluded even when the constraint is in place when the balancing area is a net importer or if transfer limits are exceeded. In other words, Bonneville's core concern that the GHG net transfer constraint will limit their ability for the contracted FCRPS to be attributed to preference customers in Washington is misplaced. Bonneville's concern can be addressed simply by identifying which contracted resources (the FCRPS) are committed capacity and then attribution of the FCRPS would not be precluded by the net export transfer constraint."[566]

NRU comments on the EDAM GHG net export constraint as well, sharing Bonneville's concern around its limits on attribution when a BAA is a net importer.[567]

Evaluation

CAISO misunderstands Bonneville's concerns with the GHG net export constraint. First, Bonneville mentions the net export constraint in comparison to the Markets+ threshold run, not Markets+ Type 1A/EDAM committed capacity. Second, Bonneville understands it can identify that the federal system amounts are contracted to load in a GHG zone and as such the net export constraint would not limit their attribution.

Bonneville's concern with the net export constraint is that it unnecessarily limits surplus energy from federal or non-federal resources from being attributed to a GHG zone (where the BAA is

[565] Draft Policy at 52.
[566] CAISO-040725 at 9-10.
[567] NRU-040725 at 4.

not in the GHG zone). For resources in Bonneville’s BAA, it unnecessarily limits attribution of surplus energy from Bonneville's BAA to California.

NRU agreed with this concern: “NRU also shares Bonneville’s stated concerns with the updated EDAM design; specifically, the unnecessary limitation of attributions from a given resource due to incorrect assumptions as to the best way to prevent “leakage”, and concerns with respect to the CAISO BAA’s net export constraint that limits attribution from resources in a BAA where that BAA is a net importer.”[568]

The net export constraint demonstrates one of the challenges of applying CAISO's BAA participation model to GHG accounting; it assumes that all resources within a BAA are dedicated to meeting load in that BAA. This is not true. For example, an independent power producer (IPP) could have wind energy not committed to load in Bonneville's BAA (or elsewhere) that it wishes to offer for attribution to California. But because Bonneville is a net importer in that hour, the IPP's wind resource would not be eligible for attribution to California. The reverse could also be true where there was surplus FCRPS relative to Bonneville's load obligations in its BAA but other circumstances in the BAA resulted in the BAA being a net importer. Consequently, the FCRPS would not be eligible for attribution to California under CAISO's net export constraint. Bonneville would not define either of these examples as avoiding leakage and secondary dispatch - in both situations the particular resource did not have a load obligation. Nevertheless, in both these situations CAISO’s net export constraint would unnecessarily limit clean, low-cost energy from being attributed to a GHG zone.

CAISO is correct that Markets+ does not have the "unique feature" of the net export constraint.[569] But from Bonneville’s perspective, that is a *benefit* of Markets+. It allows the Markets+ threshold run to limit leakage while giving resource owners flexibility. Markets+ explicitly discussed and opted to not take a BAA level look at loads and resources for determining the threshold because of the concerns raised above. Rather, Markets+ decided the market participant level was the most appropriate way to establish when resource amounts were surplus to loads.[570]

Decision

CAISO’s clarification does not impact Bonneville’s findings related to committed capacity. The CAISO net export constraint places unnecessary limitations on attribution of surplus energy on individual resources.

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[568] *Id.*
[569] CAISO-040725 at 9.
[570] *See* SPP Type 2 Specified Source Import Supplemental presentation.

ISSUE 30: Whether Bonneville should provide additional monitoring and reporting on the market GHG design and impacts to Bonneville's system mix

Draft Policy Position

The Draft Policy does not expressly discuss future monitoring or analysis, but generally notes in Section 5.2.5 that, while the nature of GHG accounting for organized markets is evolving and there are some uncertainties around how the design will work with state reporting, there is sufficient information to describe and generally assess how the market design for GHG accounting will work for Markets+ and EDAM and determine that the Markets+ design is superior to the EDAM design.

Public Comments

Both WPAG and PPC request Bonneville to provide monitoring and reporting of impacts to Bonneville's system mix. WPAG comments that "[a] monitoring plan and sub-plan will be essential to (i) ensure that BPA's participation in a day-ahead market does not interfere with its ability to meet its contractual and other legal obligations to its customers and (ii) identify topics for BPA and other participants to raise in the Markets+ stakeholder process."[571] WPAG further states that it "expects BPA to engage in SPP's stakeholder processes when necessary to ensure that it can meet its obligations under the PoC Contracts including, but not limited, to its obligations under Exhibit H related to GHG accounting."[572] PPC states that "[c]ustomers need to understand, at least at a high-level, how BPA plans to monitor and report on changes to its system mix, and how potential impacts to the carbon content of the federal system will influence BPA's bidding strategies."[573] PPC shares that even the small changes to Bonneville's Asset Controlling Supplier emission factor had impacts for some PPC members.[574]

OCGC asks whether Bonneville would commit to 1) publishing ongoing analysis on any differences between the current assessment of GHG design and realized outcomes of the GHG design and 2) explain whether and how Bonneville will confirm it made the right qualitative assessment on GHG.[575] OCGC asks Bonneville to "explain the reasons why BPA will not hold off on making a final market decision until such impacts can be more confidently analyzed."[576]

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[571] WPAG-040725 at 4-5.
[572] *Id.* at 4.
[573] PPC-040725 at 19.
[574] *Id.*
[575] OCGC-040725 at 9.
[576] *Id.*

Evaluation

In response to WPAG and PPC's comments, Bonneville points out that it provides transparent data on federal system fuel mix and associated emissions on an annual basis as part of the reporting Bonneville provides to state agencies. At this time, Bonneville is not committing to further evaluation of changes to its system mix resulting from participation in a day-ahead market, however, Bonneville is open to exploring during the implementation phase whether there is additional, specific information that might be responsive to this request. Bonneville does not publicly release its bidding strategy. Therefore, Bonneville would not disclose any potential impacts from the interplay between the carbon content of the federal system and bidding strategy within an organized day-ahead market. Such information is confidential and, if disclosed, could impact Bonneville's position in the market.

As Bonneville notes in its policy, GHG accounting for organized markets is an actively evolving area. As resources allow, Bonneville intends to continue to engage in market stakeholder processes around GHG design and evaluate such designs as new information is made available. However, Bonneville will not commit to publishing ongoing analysis between assessed and realized outcomes of GHG design, as OCGC requests.

OCGC asks how Bonneville will confirm it made the right qualitative assessment on GHG design and to "explain the reasons why BPA will not hold off on making a final market decision until such impacts can be more confidently analyzed."[577] Bonneville thoroughly assessed meaningful differences between the EDAM and Markets+ GHG designs in relation to how those differences would impact the ability of its customers to continue to claim the low-carbon attributes of the federal system. Bonneville's assessment is that there was enough sufficient information available to evaluate and determine that Markets+ better meets Bonneville's GHG principle because it is not biased in favor of one state program. The overall purpose of the Policy is to declare Bonneville's policy position in order to provide a measure of certainty to the region. Bonneville has made its policy decision based on the best available information at this time.

Decision

Bonneville does not commit to providing additional monitoring and reporting on the market GHG design and impacts to Bonneville's system mix. There is enough information available to evaluate and determine that Markets+ better meets Bonneville's GHG principle.

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[577] *Id.*

ISSUE 31: Whether Bonneville should evaluate how its decision will impact GHG emissions and states' abilities to meet their greenhouse gas emissions reduction targets and clean energy goals

Draft Policy Position

Bonneville did not address this issue in the Draft Policy.

Public Comments

A few commentors request BPA to evaluate how its decision would impact GHG emissions and help states meet clean energy goals.[578] Other commentors state BPA's decision ignores a "greener" or more "climate-friendly" alternative.[579]

Earthjustice states: "BPA must consider how day-ahead market alternatives could help or hinder the Pacific Northwest in attaining clean energy goals, mitigating GHG emissions, and reducing the emission of toxic air pollutants and other pollution from thermal generating units."[580] The State Agencies state: "BPA has not addressed whether there is more of a benefit to one market or the other in terms of reducing GHG emissions. As states with climate and clean energy policies with emissions reduction targets, the State Agencies are interested in further analysis of this question. While it may be challenging to address this question, BPA should consider further whether there are any inferences that could be made from the regional scenario analysis results (e.g., looking at generation costs) or other relevant analyses."[581]

Evaluation

While Bonneville acknowledges commenters' interests in generally understanding how a day-ahead market could impact GHG emissions and ability to meet state-driven GHG reduction targets, these are not targets that apply to Bonneville and are not legal standards that Bonneville must evaluate. Bonneville's GHG principle was developed to support Bonneville's customers' requests to evaluate how Bonneville's participation in a day-ahead market could impact GHG emissions attributed to the federal system under state GHG reporting programs and identifying impacts to customers' ability to comply with these programs.

Decision

Bonneville declines to evaluate how participation in a day-ahead market could impact GHG emissions or help states meet their individual GHG emission reduction goals.

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[578] Earthjustice-040725 at 10; OR-WA State Agencies-040725 at 7-9.
[579] Brewer-040725 at 1; *see* CSRC.
[580] Earthjustice-040725 at 10.
[581] OR-WA State Agencies-040725 at 9.

6. Preliminary Implementation and Participation Considerations for Markets+

6.1. Generation Resource Participation in Markets+

ISSUE 32: Whether Bonneville considered FCRPS operating constraints

Draft Policy Position

Bonneville discusses that the Markets+ framework allows Bonneville to manage FCRPS operations with other project purposes and within system-wide operating constraints, including operations to support Endangered Species Act-listed (ESA) fish and to provide equitable treatment for fish and wildlife with other system purposes as required by the Northwest Power Act.

Public Comments

Several commenters raised concerns about impacts from the operation and management of federal hydropower projects (i.e., dams and reservoirs) that comprise the FCRPS. For example, some commenters contend that a day-ahead market's "operational framework may alter dam operations" and state that any resulting "reduction in spill or change in water management could directly impact salmon populations."[582] Similarly, others state their concerns about "impacts stemming from operational changes to dams," impacts on aquatic ecosystems and habitats for anadromous fish, and potential impacts on fisheries.[583] Bonneville has several points in response.

Yakama Nation comments "the Market's operational framework may alter dam operations, including spill rates critical to fish passage. Any reduction in spill or change in water management could directly impact salmon populations-species that are central to Yakama culture, economy, and identify." The CTUIR is concerned that Bonneville's participation in the market "may require changes to hydro system operations that would result in impermissible impacts to both the access of the treaty fishing right and degradation of the ecosystem on which those treaty resources depend."[584] Yakama Nation and CTUIR attached to their comment a list of issues to address with Bonneville through government-to-government consultation. In this attachment they explain that day-ahead market participation must protect and enhance salmon and steelhead survival measures through dam operations such as maximizing spill when salmon and steelhead are migrating.[585] They also share several impacts and recommendations from the

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[582] Yakama-040325 at 2 (discussing dam and reservoir operations to improve salmon and steelhead survival and tribe's interest in "ensur[ing] that an expanded day-ahead market will protect and enhance" such operations); CTUIR-040725 at 1 ("without adequate fish operation protections, [BPA's proposal to join Markets+] could make salmon survival worse").
[583] ATNI-040725 at 1-2.
[584] CTUIR-040725 at 1.
[585] Yakama-040325 at 4; CTUIR-040725 at 5.

Columbia River Inter-Tribal Fish Commission (CRITFC) 2022 Energy Vision for the Columbia River Basin.[586]

The Affiliated Tribes of Northwest Indians (ATNI) raise concerns about the impacts of day-ahead market participation related to the operations and management of federal hydropower projects (*i.e.,* dams and reservoirs) that comprise the Federal Columbia River Power System (FCRPS). ATNI asserts that Bonneville has not fully examined the Policy decision's impacts "stemming from operational changes to dams."[587] ATNI requests that Bonneville explain "[w]hat operational changes to dam management are anticipated in relation to BPA's participation in a day-ahead market?"[588] CRITFC comments that Bonneville must evaluate potential impacts of the Policy decision to tribal and treaty resources including "the effects that market participation may have on management of federal power system, its operations, their consistency with currently negotiated fish operations, and the ability to improve those operations as needed for fish."[589]

Earthjustice argues participation in Markets+ "may also lead to the operation of generating projects either outside normal operating constraints or in ways that undermine the purpose of those constraints."[590]

Additionally, Bonneville received feedback from public commenters recognizing that in its operations and management of hydropower resources, Bonneville "must also consider fisheries, recreation, flood control, shipping and more."[591]

Evaluation

First, Bonneville's policy decision here towards Markets+—to facilitate its eventual entrance into Markets+, rather than EDAM—is not a decision to operate or manage the FCRPS in any particular way in the future and does not dictate what the operating limits or constraints for that system are or will be. Such matters are determined separately through decision processes specific to FCRPS operations and management; these processes account for and address Bonneville's various statutory obligations, including those related to fish and wildlife. Bonneville would submit the operational limits and constraints resulting from these processes, including those related to fish and wildlife, to the market when and if Bonneville participates.[592] Operations and

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586 *Id*.
587 ATNI 040725 at 1.
588 *Id*. at 2.
589 CRITFC-040725 at 2.
590 Earthjustice 040725 at 7.
591 Bowler-032125 at 1.
592 For example, the Columbia River System operations, maintenance and configuration are consistent with the Selected Alternative in the 2020 Columbia River System Operations Environmental Impact Statement and Record of Decision and associated documents as well as the proposed action consulted upon in the National Marine Fisheries

management actions (including Bonneville's power marketing) are then undertaken consistently with the decisions made in those processes.

The choice to enter a day-ahead market does not change BPA's obligation to continued river operations intended to benefit fish passage, fish survival, and other environmental needs. Dam operations will continue to be implemented consistent with requirements and obligations in place at the time, for example, current requirements are contained in the 2020 Columbia River System Operations (CRSO) Environmental Impact Statement (EIS) ROD, the 2020 Columbia River Biological Opinions issued by the National Oceanic Atmospheric Administration Fisheries and the U.S. Fish and Wildlife Service (USFWS), and associated operating plans (includes Water Management Plan and Fish Passage Plan), and other established United States Government commitments. The same would be true for any operations and management actions that Bonneville undertakes in the future as a day-ahead market participant.[593] The terms of any day-ahead market implementation agreement that Bonneville eventually enters into would reinforce this, as Bonneville's legal assessment explained: "[A]n agreement to participate in a day-ahead market must expressly acknowledge and not infringe on Bonneville's authority to meet its statutory obligations and contractual requirements."[594] Importantly, this would assure Bonneville can continue to make its power marketing decisions consistent with its applicable NEPA and ESA documents.

Second, if Bonneville ultimately decides to join Markets+ in the future (i.e., by signing a final implementation agreement to become a market participant), the market would "alter dam operations" as some commenters appear to assert.[595] To the contrary, FCRPS operations and management actions, including for Bonneville's power marketing purposes, would continue to be made in coordination with the U.S. Army Corps of Engineers and Bureau of Reclamation subject to and consistent with Bonneville's obligations and applicable NEPA and ESA documents, as explained above. Participation in a day-ahead market does not supersede or define those obligations.

Service and U.S. Fish and Wildlife Service biological opinions for the Operations and Maintenance of the Federal Columbia River System. The Columbia River System (14 dams that are part of the FCRPS) operate within normal operating limits consistent with the Columbia River System Operations Environmental Impact Statement and Record of Decision and associated NEPA and ESA documents, including the annual operating documents, such as the Water Management Plan and the Fish Passage Plan and its appendices.

[593] *See* Policy § 6.1.1.1. ("Bonneville's power marketing services and activities, and its actual power operations to meet load obligations, are conducted consistent with applicable Biological Opinions and are within existing operating constraints and normal operating limits of FCRPS projects. The Markets+ framework allows Bonneville to manage FCRPS operations with other project purposes and system-wide operating constraints, including operations to support ESA-listed fish and to provide equitable treatment for fish and wildlife with other system purposes as required by the Northwest Power Act.").

[594] Policy at 73 (App. A, Legal Assessment).

[595] *See, e.g.*, Yakama-040325 at 1.

Third, nothing about Bonneville's participation in Markets+ would alter Bonneville's existing ability to conduct operations and management actions that address its statutory obligations for fish and wildlife, such as fish passage. Again, "an agreement to participate in a day-ahead market must expressly acknowledge and not infringe on Bonneville's authority to meet its statutory obligations and contractual requirements."[596] In addition, Markets+ would preserve Bonneville's discretion to choose whether and when to offer generation for sale in the day-ahead market, meaning that such offers could be sized and timed to ensure that FCRPS operations comport with existing requirements, such as operations for fish.[597] (The same would be true of EDAM.)[598] Even after making such offers, Bonneville may update them in real-time when planned operations need adjustment in response to changing constraints or limitations in the system, including adjustments necessary for compliance with environmental obligations.[599]

One commenter notes that even "within the constraints imposed by these legal requirements there is considerable flexibility in where, when and how power from the FCRPS is generated for BPA to market," and argues that this "flexibility can be exercised to provide less – or more – favorable conditions" for salmon and other species.[600] This is no different than the current paradigm (under EIM) where Bonneville has flexibility to generate and market power within operational limitations and constraints established by other processes for the FCRPS.[601] In any event, decisions about the use of that flexibility within Markets+ would occur in the future and, within the system's existing limitations and constraints, would continue to be subject to applicable NEPA and ESA documents, including the annual operating documents such as the Water Management Plan and Fish Passage Plan.[602] A day-ahead market (and this policy decision) simply do not make such determinations.

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596 Policy at 73 (App. A, Legal Assessment).
597 *See id.* § 6.1.1 (Federal Generation) ("Bonneville expects to use self-schedules and offer ranges to ensure the FCRPS operates within its limits while allowing for system optimization. In addition to hourly minimum/maximum constraints, Markets+ has also developed an additional constraint, allowing Bonneville to communicate a daily energy maximum for each resource in the day-ahead optimization in addition to the hourly offer range limits. Setting a daily energy maximum helps ensure that Bonneville can honor operational obligations and constraints while still allowing for economic optimization of the system.").
598 *See id.* § 6.1 (Generation Resource Participation in Markets+) ("both markets allow for 'self-scheduling'").
599 *See id.* ("[B]ecause offers can be updated through real-time, Bonneville will be able to make adjustments to its planned operations in the market as fuel certainty materializes."); *id.* § 2.4 (Day-Ahead Market Framework) ("The market operator receives updated constraint information in day-ahead and real-time data submittals from market participants and reliability entities. Transmission Operators and BAs update constraint information on the elements or system areas that have new or existing limitations. Resource Owners/Operators submit hourly offer information about the minimum and maximum amount of generation they are willing to sell . . . .").
600 Earthjustice-040725, at 20.
601 *E.g.*, the Selected Alternative in the 2020 Columbia River System Operations Environmental Impact Statement and Record of Decision and associated documents.
602 *Id.*

Fourth, appropriate tools that help Bonneville meet its environmental obligations, with respect to FCRPS operations and management, would remain available as needed if Bonneville joins Markets+. These include, for example, the Oversupply Management Protocol (OMP) which allows Bonneville to displace other power generation, during periods of high river flows and low power load, so that Bonneville can run water through its generating turbines rather than spilling it to the point it would cause total dissolved gas levels harmful to salmon and other aquatic species.[603] At the same time, under Markets+, Bonneville would continue to exercise its statutory authority to buy short-term power to replace power generating capability lost as a result of spill for fish passage purposes at FCRPS dams.[604] In fact, by participating in a day-ahead market, Bonneville may at times have access to a broader pool of short-term power products and potentially at better prices, which would allow Bonneville to provide fish operations and serve power load in a more economical manner.

Finally, some comments cited to § 4(h)(11)(A) of the Northwest Power Act, which includes the requirements that Bonneville's operation and management of federal hydropower projects provide fish and wildlife with equitable treatment compared to the other congressionally-authorized purposes of such projects, and to take the Northwest Power and Conservation Council's fish and wildlife program into account in doing so.[605] The foregoing discussion demonstrates that future FCRPS operations and management actions, for Bonneville's power marketing purposes as a day-ahead market participant, would continue to be subject to this and other relevant statutory provisions and Bonneville would retain the appropriate discretion and tools to ensure that it is satisfied in a manner consistent with applicable NEPA and ESA documents for FCRPS operations and management.[606]

Decision

Bonneville's policy decision here—to facilitate its entrance into Markets+, rather than EDAM—does not implement FCRPS operations or management actions in fact, which would continue to be subject to applicable NEPA and ESA documents, including the annual operating documents such as the Water Management Plan and Fish Passage Plan. Bonneville's policy regarding Markets+ will not alter the boundaries for such operations without additional environmental compliance and associated operations and management decisions. Bonneville's policy ensures that Bonneville will continue to satisfy its statutory obligations related to fish and wildlife mitigation when Bonneville ultimately executes a Markets+ participation agreement or

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[603] *See* Policy § 6.5.3 (Oversupply Management Protocol).
[604] *See* Federal Columbia River Transmission System Act, 16 U.S.C. § 838i(b)(6)(iv).
[605] *See* 16 U.S.C. 839b(h)(11)(A)(i)–(ii).
[606] *See Confed. Tribes of the Umatilla Indian Reservation v. Bonneville Power Admin.*, 342 F.3d 924, 932 (2003) (identifying "current and future adjustments to planning and operations" supporting fulfillment of the equitable treatment mandate of § 4(h)(11)(A)) (internal quotations omitted); *see also, e.g.*, Columbia River System Operations Environmental Impact Statement Record of Decision, § 5.5 (Sept. 2020) *available at* https://usace.contentdm.oclc.org/utils/getfile/collection/p16021coll7/id/16248.

equivalent after completing all required decision and implementation processes necessary to join Markets+.

6.2. Ensuring Adequate Supply in Markets+

ISSUE 33: Whether Bonneville will provide an adequate supply of power if it participates in Markets+

Draft Policy Position

Bonneville addressed how it will ensure adequate supply while participating in Markets+ in section 6.2 in the Draft Policy.

Public Comments

Lincoln and Modern comment that Markets+ will help Bonneville fulfill its power supply obligations.[607]

In support of Bonneville's decision to pursue Markets+, the Joint Authors state Markets+ "is anticipated to be substantial in size with exceptional generation and load diversity[.]"[608] The Joint Authors point to a "[p]eak demand of over 52 gigawatts," load and resource diversity with a complementary mix of summer and winter peaks and surpluses; clean, flexible supply with northwest hydro and solar in the Desert Southwest; and large geographic footprint containing parts of 11 states.[609]

BlueGreen Alliance comments that joining Markets+ is "likely to result in less reliable power, or that customers will have pay more to ensure they have reliable, uninterrupted electricity."[610]

Earthjustice and RNW comment that a larger footprint will provide a larger and more diverse resource base to provide greater optimization and reliability benefits.[611] RNW also requests further explanation regarding Bonneville's analysis of geographic diversity, optimization, and other reliability benefits of joining Markets+.[612] Earthjustice also comments that joining a market "with a larger footprint and more diverse resource mix like EDAM would give BPA more

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607 Lincoln-040425 at 1; Modern-040425 at 1.
608 Joint Authors-040725 at 2.
609 *Id.* at 2-3.
610 BlueGreen Alliance-040725 at 2.
611 Earthjustice-040725 at 18, RNW-040725 at 19-21.
612 RNW-040725 at 21.

flexibility to meet demand without the services of [the Lower Snake River] dams, as compared with joining a market with a smaller footprint."[613]

Evaluation

In the Draft Policy, Bonneville stated that it "will continue to plan for its long-term firm power load service obligations by managing its existing resources and by acquiring resources in advance based on forecasted need."[614] Bonneville also stated that it uses "its Pacific Northwest Loads and Resources Study . . . and . . . its Resource Program, both of which supplement the regional power plan prepared by Northwest Power Conservation Council pursuant to the Northwest Power Act."[615] Bonneville also noted that its "future participation in WRAP binding operations and Markets+ will provide greater transparency and documentation as to how these obligations are met."[616]

Whether in EDAM or Markets+, every participant is expected to have a long-term plan to meet its expected loads prior to participating in the market. As explained in Issue #21, Bonneville prefers the design of Markets+ because it provides an actual RA standard by requiring all entities to participate in WRAP, while EDAM relies solely on RS tests. In short, all entities have an obligation to ensure an adequate power supply independent of a day-ahead market, and Bonneville stands ready to meet that obligation. The RA requirement of Markets+ is a key metric in determining the benefits of joining Markets+.[617] While Bonneville acknowledges that the size and connectivity of a day-ahead market footprint factors into the magnitude of benefits, as the Joint Authors recognize, and as explained in the Policy, Bonneville expects the footprint of Markets+ to provide optimization and reliability benefits to Bonneville's customers over the status quo.[618] When examined in conjunction with the superior governance and stakeholder process and design of Markets+, Bonneville continues to view Markets+ as the best day-ahead market option.[619]

Decision

Bonneville will be able to provide an adequate supply of power in Markets+.

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[613] Earthjustice-040725 at 9.
[614] Draft Policy at 58.
[615] *Id.*
[616] *Id.*
[617] *See* Policy at 12-13.
[618] Joint Authors-040725 at 2-3; *see also* Policy at 58.
[619] Policy at 58.

6.3. Ancillary and Control Area Services

ISSUE 34: Whether Bonneville would change the way it provides Ancillary and Control Area Services (ACS).

Draft Policy Position

ACS is discussed in Section 6.3 of the Draft Policy. In the Draft Policy, Bonneville concluded that it "does not expect Markets+ to change how ACS is provided," as the Markets+ Real-Time Balancing Market (RTBM) does not supersede the need for Bonneville to provide balancing capacity as the BA.[620] Bonneville acknowledged that incorporating the RTBM will likely require the agency to "revise its Tariff, Rates, and Business Practices . . . in the appropriate processes."[621]

Public Comments

NIPPC comments that "BPA must be prepared to thoroughly revisit its existing rates structures, cost allocations, and operational practices to make them consistent with the market design."[622] NIPPC raises two specific questions related to ACS: 1) "Does BPA contemplate changes to its existing reserve products?"; 2) "Will joining a market allow BPA to reduce the quantity of capacity needed for balancing reserves?"[623] Ultimately, "NIPPC believes that an analysis of each of these topics in the context of each market's detailed designs will provide valuable insights to both BPA and its customers in reaching a decision about which market BPA should join."[624]

Evaluation

Bonneville agrees with NIPPC that it must ensure its rates, tariff, and other operational practices are consistent with the design of Markets+. As stated in the Draft Policy, because neither Markets+ nor EDAM provides a "centrally organized market for the capacity component of ACS . . . ," Bonneville will still have to hold capacity to fulfill its obligations as a balancing authority.[625] As a result, Bonneville does not anticipate significant changes to its existing reserve products or the quantity of capacity needed for balancing reserves, other than minor adjustments to ensure those products are consistent with the design of Markets+.

Bonneville already has experience with the WEIM and did not need to make substantial changes to its ACS to join that market. As stated in the Draft Policy, the RTBM operates in a similar manner to the WEIM.[626] Therefore, an analysis of each market's detailed designs with respect to

[620] Draft Policy at 59.
[621] *Id.*
[622] NIPPC-040725 at 17.
[623] *Id.* at 14.
[624] *Id.*
[625] Draft Policy at 58.
[626] *Id.* at 61.

ACS would not provide any more insight. Bonneville will address specific implementation details in its tariff and rate proceedings during implementation of Markets+.

Decision

Bonneville anticipates providing the same ACS as it does today if it becomes a participant in Markets+. Bonneville will address these implementation details in its rates and tariff terms and conditions proceedings.

ISSUE 35: Whether Bonneville would revise its penalty rates

Draft Policy Position

ACS is discussed in Section 6.3 of the Policy. Bonneville did not address the Intentional Deviation Penalty Charge issue in the Draft Policy.

Public Comments

NIPPC comments that "extra-market penalties" imposed by Bonneville may not allow customers to "take advantage of the features of the Markets+ design."[627] NIPPC cites its experience in the WEIM where Bonneville requires "variable energy resource generation customers to schedule to their forecast." According to NIPPC, Bonneville "imposed significant penalties on customers who choose to schedule their resources in a way that limits their exposure to imbalance charges in the market. Those penalties, however, do not exist in the market design of WEIM."[628] "NIPPC is concerned that BPA will take a similar approach to Markets+ and attempt to impose extra-market penalties and additional requirements on BPA's transmission customers that are not expressly part of the Markets+ tariff or Protocols[.]"[629]

Evaluation

The Intentional Deviation Penalty Charge is designed to address the use of capacity that Bonneville holds for providing balancing reserves. The WEIM, EDAM, and Markets+ are specifically not capacity markets for the capacity component of ACS.[630] The Intentional Deviation Penalty Charge is still necessary to incentivize variable energy resources to schedule to appropriate forecast values to avoid scheduling errors that are inconsistent with Bonneville's capacity forecast. Therefore, the Intentional Deviation Penalty Charge is necessary to address services that are not covered by a day-ahead market, whether Markets+ or EDAM. While Bonneville expects the Intentional Deviation Penalty Charge to complement its participation in

[627] NIPPC-040725 at 17.
[628] *Id.*
[629] *Id.*
[630] Policy at 62-63.

Markets+, Bonneville is open to reevaluating its practices as it gains more experience in Markets+. Any such reevaluation and subsequent decision will be part of Bonneville's rate proceeding.

Decision

Bonneville anticipates needing the Intentional Deviation Penalty Charge while participating in Markets+. However, any decision regarding changing the Intentional Deviation Penalty charge must be made through Bonneville's rate proceedings.

ISSUE 36: Whether balancing reserves would be used to support "high priority" export transactions

Draft Policy Position

ACS is discussed in Section 6.3 of the Policy. Bonneville did not address the high priority export transactions issue in the Draft Policy.

Public Comments

In its comments, NIPPC raises the question, "If customers purchase balancing reserves from BPA, will the balancing reserves support 'high priority' export transactions?"[631]

Evaluation

As stated in the Draft Policy, Markets+ does not change Bonneville's obligations to provide ACS.[632] For export transactions, Markets+ assigns a market designation, "high priority"[633] or "uncommitted,"[634] that the market operator may utilize in cases of market scarcity or overgeneration in the market footprint. A "high priority" export transaction is backed by committed export supply and will be included in a Market Participant's must offer obligations. If an ACS customer taking balancing services from Bonneville can otherwise meet the high priority export requirements, ACS should support the transaction.

[631] NIPPC-040725 at 14.
[632] Draft Policy at 58.
[633] An Export Interchange Transaction that is backed by committed export supply. Committed export supply includes Market Participant's Resource Adequacy Program obligations to load outside the Markets+ Footprint. Committed export supply also includes source specific sales to load outside the Markets+ Footprint where the portion of the export that is high priority is the portion that is supported by an identified Resource's available surplus capacity. High Priority Export Interchange Transactions will be included in the Market Participant's must offer obligation. *See* Markets+ Tariff § 1 (Definitions, High Priority Export Interchange Transaction).
[634] An Export Interchange Transaction that is not a High-Priority Export Interchange Transaction. *See* Markets+ Tariff § 1 (Definitions, Uncommitted Export Interchange Transaction).

Decision

Participation in Markets+ does not eliminate Bonneville's requirement to offer ACS, and ACS will support high priority export transactions.

6.4. Operational and Commercial Seams

ISSUE 37: Whether Bonneville adequately considered seams congestion, reliability, and other seams issues.

Draft Policy Position

Bonneville primarily discussed seams and reliability issues in Section 6.4 and Appendix D of the Draft Policy.

Public Comments

Multiple commenters support Bonneville's seams analysis. The Joint Authors "support the Draft Policy's recognition that there are multiple types of seams in the West" and recognize that seams "will continue to exist regardless of which organized market participants decide to join."[635] The Joint Authors also comment that "Bonneville's careful assessment of seams issues is both detailed and thorough."[636] The Joint Authors also state that seams negotiated between two organized markets are "far more likely to result in equitable resolution of seams" as the seams will not be "managed according to the rules of [the same] market."[637]

Powerex states that "Bonneville provides a thorough analysis of what will be required" to manage seams, that Bonneville has experience managing and negotiating seams, and that negotiations between "two similarly situated market operators . . . reduce[s] the risk of preference for any specific type of entity or geographic location."[638]

PPC expects seams "challenges to be manageable and the advantages resulting from other aspect[s] such as market design and governance outweigh the risks associated with trading across market seams." PPC also commends Bonneville's identification of seams issues in Appendix D, and notes that Markets+ has a Seams Working Group "established to address seams issues."[639]

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[635] Joint Authors-040725 at 4.
[636] *Id.*
[637] *Id.*
[638] Powerex-at 4.
[639] PPC-040725 at 5.

Tacoma states that Bonneville has "thoroughly evaluated potential seams scenarios throughout its workshop process and in its March 2025 Day-Ahead Market Draft Policy" and that Bonneville's "conclusion that they 'and others will need to work collaboratively to manage these seams while continuing to prioritize reliability' is the only responsible conclusion at this stage of market decision and implementations."[640] Tacoma also states that Bonneville "will be in a better position to collaboratively manage seams issues as a member of Markets+" due to the governance structure of Markets+.[641]

Multiple commenters also express concerns with Bonneville's seams analysis. SCL comments that "the creation of multiple DAMs and associated real-time markets will change existing market and Reliability Coordinator (RC) footprints in the PNW and introduce new seams on top of those that already exist."[642] SCL states "differences in market design will create hurdles and impediments to transacting across a seam" and that Bonneville "has not adequately addressed how these costs and risks would be mitigated and is inappropriately concluding that it will derive benefits that will be difficult to achieve under the proposed footprint."[643]

SCL specifically expresses concern with the lack of connectivity, in addition to the ability to "efficiently manage congestion and import energy into the PNW during times of high demand."[644] SCL also states that market seams will create new reliability risks as it "will make it more challenging to manage operational issues when they arise, given the additional coordination and lack of complete regional authority."[645] According to SCL, this complexity means Bonneville "is less likely to experience" reliability benefits in Markets+, as "those benefits are best realized from optimization of a broad footprint across multiple time horizons and with all transmission available in the market."[646] SCL also expresses concern with the effectiveness of seams agreements, stating that "parties are overconfident about what can be resolved and underestimate how difficult it will be to capture potential benefits through coordination."[647]

Earthjustice states "joining Markets+ will create seams in the regional transmission system that make it difficult to transact and exchange power"[648] and that "creating market seams by joining the smaller of two day-ahead markets with less contiguity within and outside the BPA region,

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[640] Tacoma-040225 at 6.
[641] *Id.*
[642] SCL-040725 at 20.
[643] *Id.* at 20, 25.
[644] *Id.* at 21-22.
[645] *Id.* at 22.
[646] *Id.*
[647] *Id.* at 24.
[648] Earthjustice-040725 at 8.

increases the cost of transacting across regional markets."[649] Earthjustice also states that Bonneville's finding that Markets+ provides more benefits than staying in the WEIM rests on a "speculative" assumption that the two markets can come to agreement on seams issues.[650] Additionally, Earthjustice states, "Accordingly, BPA must consider the extent to which its day-ahead market choice will lead to splitting most of the Western Interconnection into two separate day-ahead markets, and how that will affect the reliability of the grid and the risk of blackouts during extreme weather events as compared to its other market choices."[651]

RNW expresses similar concerns with multiple market footprints, stating that "it will create costly seams issues that will be difficult to resolve and will erode the reliability benefits that can be achieved through a broader market."[652] RNW also states that "it is unlikely that seams will be resolved effectively or efficiently, leading to cost and risk to BPA's customers and the region." RNW points out that Eastern markets "took many years to establish seams agreements for market-to-market transactions and still lack adequate solutions that minimize risk and maximize trading opportunities," and that "challenges arise despite carefully crafted seams agreements."[653] RNW also comments that the creation of seams will have serious impacts on reliability and Bonneville's decision "deserves enhanced scrutiny" given Bonneville's "transmission system backbone."[654] RNW does acknowledge, however, that seams are "a difficult issue to address until seams agreements are created[.]"[655]RNW also requests Bonneville address seams and related issues in its future analysis and the Final ROD.[656]

According to BlueGreen Alliance, Bonneville "will inevitably have to negotiate complex seams agreements to coordinate with the other distant and fragmented Markets+ participants across the West" and that Bonneville "would be running two markets on its own grid since some of the transmission users will be participating in EDAM while BPA will be participating in Markets+, effectively creating a seam *within* the BPA footprint."[657] BlueGreen Alliance also expresses concern with "less reliable power" and concludes that the complexity and costs "have not been fully contemplated by BPA in their analysis."[658]

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[649] *Id.* at 23.
[650] *Id.*
[651] *Id.* at 19.
[652] RNW-040725 at 14.
[653] *Id.* at 17.
[654] *Id.* at 20.
[655] *Id.*
[656] *Id.* at 21.
[657] BlueGreen Alliance-040725 at 2.
[658] *Id.*

Eugene Water and Electric Board (EWEB) comments that joining Markets+ "will create new seams and introduce significant efficiency challenges both for BPA and the broader region as distant loads and resources struggle to interact with each other across heavily congested paths."[659]

CAISO comments that Bonneville's decision "could create additional operational and market seams within the Pacific Northwest and between the Pacific Northwest and the rest of the West, including California."[660] According to CAISO, "[s]eams arrangements are not a substitute for an integrated market and there will not be a consolidated balancing area in the Pacific Northwest anytime soon" and that "it is not yet clear to the ISO how this would work out in practice."[661] CAISO also states that, although "the West has managed operational seams" in the past, "seams associated with day-ahead markets and multiple balancing areas in the Pacific Northwest would require an acute level of care and attention with little upside benefit, and material downside risk to reliability and affordability."[662] However, CAISO expressed continued "commitment to working collaboratively with Bonneville and other parties on these complex issues."[663]

PacifiCorp and PGE express concerns with "inefficiencies" caused by market seams, even if managed.[664] PacifiCorp and PGE comment that the inefficiencies will have an economic impact on retail customers, and that Bonneville's "analysis may not adequately consider whether these customers could face higher wholesale electricity costs due to less efficient utilization of generation resources and transmission infrastructure across the Western Interconnection."[665]

PG&E comments that seams will create "inefficiencies" and that EDAM is the solution.[666] PG&E Comments at 1. PG&E also states that Bonneville will need to "purchase Available Transfer Capacity (ATC) to receive priority wheeling" in order to reach other members of Markets+. According to PG&E, "ATC is restricted by planning assumptions which means BPA will only be able to enjoy a limited amount of available capacity." [667]

The State Agencies, Yakama, and SCL all express concerns with Bonneville potentially changing RCs and having two RCs in the Pacific Northwest.[668]

Evaluation

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[659] EWEB-040725 at 1.
[660] CAISO-040725 at 13.
[661] *Id.*
[662] *Id.*
[663] *Id.*
[664] PAC_PGE-040725 at 5.
[665] *Id.* at 6.
[666] PG&E-040725 at 1.
[667] *Id.*
[668] OR-WA State Agencies-040725 at 6-7; SCL-040725 at 20.

Bonneville acknowledges many commenters' concerns that the additional seams created by having two day-ahead markets may create inefficiencies and will be challenging to resolve. These seams include commercial and operational seams and congestion. In Appendix D and E to the Policy, Bonneville has identified the many seams that will need to be addressed prior to participation in Markets+. However, Bonneville believes the West is up to the challenge and resolving these issues is in the best interest of the entire interconnection.

The West has a history of working together to resolve seams issues. Bonneville has 18 adjacent BAAs and 15 adjacent Transmission Service Providers, several of which are located within its BAA, that it must coordinate with on a day-to-day basis. This has culminated in operational arrangements and agreements, such as the Coordinated Transmission Agreement (CTA), that have effectively mitigated seams issues. The CTA established controls for the reliable operation of the WEIM on Bonneville's transmission system consistent with Bonneville's other contractual and tariff obligations. The CTA was entered into *prior* to Bonneville joining the WEIM, to facilitate other entities' entry into the WEIM. While mitigating the seams created by two real-time markets may present more difficult challenges, Bonneville believes similar arrangements are achievable. The CTA provides a starting point for managing any seams created by joining Markets+. Bonneville appreciates CAISO's commitment to work collaboratively to solve these issues.[669] And as other commentors point out, entities in both Markets+ and EDAM have an incentive to ensure their market decisions are adequately represented in any seams agreements.

Bonneville also disagrees with the implications of many commenters that the seams issues are solely a result of Bonneville's decision to pursue participation in Markets+. As noted in the Policy Letter, PacifiCorp and PGE have moved forward with the decision to participate in EDAM based on their evaluation of which market is in their best interests, just as Bonneville has done with its decision to pursue participation in Markets+. However, there has been very limited discussion of seams with those entities, despite their decision relying heavily on use of the Bonneville transmission system, creating the same seams with which many commenters take issue, including PacifiCorp and PGE. All entities will need to rely on negotiating seams agreements, regardless of the day-ahead market in which they decide to participate.

Regarding commentors' reliability concerns about multiple seams, a day-ahead market, whether EDAM or Markets+, does not relieve Bonneville or any other entity of its reliability responsibilities. Bonneville must still meet its various obligations under the NERC Reliability Standards as a BA, Transmission Owner, Transmission Operator, Transmission Planner, and other roles. Bonneville also retains the obligation to have an approved RC, a role in which CAISO and SPP have substantial experience in the Western Interconnection, including managing seams between RCs. Bonneville is still making the decision whether to change RCs or not.

[669] CAISO-040725 at 13.

In addition, Bonneville disagrees with comments that suggest participating in Markets+ will result in additional congestion or curtailments. As stated in the Draft Policy, Bonneville "expects even greater congestion management effectiveness with the addition of a security constrained day-ahead market optimization."[670] While there will likely be challenges in operational coordination between two different markets, Bonneville reiterates its confidence that the region can mitigate issues through seams agreements.

Finally, while commenters' concerns about the market footprint affecting the scale of optimization benefits are valid, Bonneville still believes there will be optimization and congestion benefits from participating in Markets+ once the requisite seams arrangements are finalized.

Decision

Bonneville adequately considered congestion, reliability, and other seams issues in its decision to pursue participation in Markets+.

ISSUE 38: Whether Bonneville has adequately considered implementation complexity

Draft Policy Proposal

Consideration of implementation details is addressed in Appendix F of the Policy.

Public Comments

Commenters express concern that implementation of Markets+ would be challenging for a variety of reasons, including that Markets+ will require Bonneville to abandon systems already in use for WEIM participation,[671] that staffing and other resource challenges may negatively impact implementation,[672] and that Bonneville may not have adequately considered all possible implementation costs.[673]

Commenters are also concerned that the implementation timeline is unknown or that it will be excessive.[674] Bonneville was urged to move quickly to address implementation issues, including policies around Markets+ participation.[675]

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[670] Draft Policy at 60.
[671] SCL-040725 at 4; *see also* RNW-040725 at 9 (questioning whether Bonneville customers are still paying off WEIM software costs).
[672] OCGC-040725 at 13; SCL-040725 at 49; RNW-040725 at 9; Dotson-040725 at 2-3.
[673] OCGC-040725 at 6; PAC_PGE-040725 at 5; WPAG-040725 at 4-6.
[674] NIPPC-040725 at 11, 16; RNW-040725 at 9.
[675] NIPPC-040725 at 18; Umatilla-040425 at 2.

Commenters request clear information on the allocation of implementation costs, including allocation of implementation costs to customers who will benefit,[676] and that Bonneville ensure implementation does not negatively impact various customer groups, including by ensuring participation by all generation in Bonneville's BAA is enabled.[677]

NIPPC recognizes that "future rate and tariff amendment proceedings to implement participation in a day-ahead market" will be necessary.[678]

Evaluation

The Policy contains the best available information to date. First, as Appendix F acknowledges, future implementation details are estimates only. Speculating about timing and exact details is beyond the scope of this policy, which sets the direction for future proceedings. Second, as NIPPC noted, future process around implementation details, including rate and tariff cases, will be necessary, and Bonneville will share details of those processes when they are scheduled.

Decision

Full details regarding implementation of Markets+ are outside the scope of this Policy. Bonneville recommends that its customers continue to engage with Bonneville as Markets+ implementation unfolds.

6.5. Operational Tools

ISSUE 39: Whether Bonneville's participation in Markets+ will affect the Oversupply Management Protocol (OMP)

Draft Policy Proposal

In the Draft Policy, Bonneville proposed keeping its existing operational tools when it joins Markets+.[679] These operational tools include Operational Controls for Balancing Reserves (OCBR), Curtailment Advisor, and OMP.[680] Bonneville acknowledged that these operational tools "will require adjustments to work within the framework and day-ahead market timelines of Markets+" and that Bonneville will work "to identify which operational tools will require adjustments as part of implementation scoping and will work with the market operators as necessary as part of that scoping process."[681]

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[676] NIPPC-040725 at 12; PAC_PGE-040725 at 4; RNW-040725 at 9.
[677] NIPPC-040725 at 16.
[678] *Id.* at 18.
[679] *Id.* at 61-62.
[680] *Id.* at 62-63.
[681] *Id.* at 62.

Public Comments

NIPPC posed a number of questions related to OMP if Bonneville participates in Markets+:

- How will BPA's participation in a day-ahead market impact the need for OMP?
- What are the market settlement implications for BPA and its customers of OMP?
- How will BPA's negative pricing policy apply in an organized day-ahead market?
- How will deployment of balancing reserves be impacted when the market price is negative?
- What does BPA anticipate its bidding strategy will be in a day-ahead market when load, river conditions, and BPA's environmental obligations lead to a condition in which it would trigger the OMP in today's bilateral market?
- How will the day-ahead market rules ensure that BPA does not shift the cost of its environmental obligations to other market participants?
- How will price formation in a day-ahead market work when the LMP in BPA's Balancing Area are negative—assuming other generators in BPA are willing to deliver their output at negative prices?
- Does BPA intend to amend its Negative Pricing Policy?[682]

Evaluation

Bonneville acknowledges that some changes to the implementation of OMP may be necessary to accommodate market rules and will monitor the issue during implementation. Bonneville expects that many of the changes implemented for WEIM will be applicable in Markets+, and that additional changes should be minimal. However, as stated in the Draft Policy, "[w]hile Markets+ may provide Bonneville additional opportunities to market generation during times of high flows, Bonneville still needs a mechanism to ensure compliance with its environmental responsibilities."[683] OMP is memorialized in Attachment P to Bonneville's Tariff, and is approved by FERC. Bonneville must follow the requirements laid out in Attachment P, which ensures that any changes made to the implementation of OMP in Markets+ will preserve OMP's basic operations, "including offering to sell power at zero cost[.]"

Bonneville does not publicly release its bidding strategy. Bonneville will continue to adhere to Attachment P requirements, "including offering to sell power at zero cost[.]" If participating in Markets+, Bonneville will bid into the market, and the market will settle accordingly at whatever price the market dictates. Limitations on Bonneville's resources due to Bonneville's environmental responsibilities will be modeled as a constraint in the market just like any other

[682] NIPPC-040725 at 14-16.
[683] Draft Policy at 61.

resource. In addition, Attachment P will ensure that displaced generators are compensated for displacement.

Decision

Bonneville identified the need to retain OMP when it participates in Markets+ and will make any necessary changes to accommodate market rules. Additional information will become available during the implementation phase of Markets+.

ISSUE 40: Whether Bonneville's participation in Markets+ will affect Operational Controls for Balancing Reserves (OCBR)

Draft Policy Proposal

In the Draft Policy, Bonneville proposed keeping its existing operational tools when it joins Markets+.[684] These operational tools include OCBR, Curtailment Advisor, and OMP.[685] Bonneville acknowledged that these operational tools "will require adjustments to work within the framework and day-ahead market timelines of Markets+" and Bonneville will work "to identify which operational tools will require adjustments as part of implementation scoping and will work with the market operators as necessary as part of that scoping process."[686]

Public Comments

NIPPC posed a number of questions related to OCBR if Bonneville participates in Markets+:

- What are the market settlement impacts of BPA's deployment of Operational Controls for Balancing Reserves (OCBR) to customers and BPA in each market?
- Can BPA's bidding strategy in a real-time market deplete the availability of reserves and trigger OCBR even though flexible reserves may still be available to the market at a higher price?[687]

Evaluation

Bonneville acknowledges that some changes to the implementation of OCBR may be necessary to accommodate market rules and will monitor the issue during implementation. Bonneville expects that many of the changes implemented for WEIM will be applicable in Markets+, and

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[684] *Id.*
[685] *Id.* at 60-61.
[686] *Id.* at 60.
[687] NIPPC-040725 at 14.

that additional changes should be minimal. However, OCBR is intended to manage the depletion of balancing reserve capacity that Bonneville holds to meet its obligations as a BA, and Bonneville still retains these obligations in Markets+. As stated in the Draft Policy, "OCBR is a real-time tool and the day-ahead market elements of Markets+ should not have any impact."[688]

Decision

While Bonneville may have to make implementation changes to OCBR, participation in Markets+ should not change how Bonneville uses OCBR. Additional information such as potential settlement impacts will become available during the implementation phase.

6.6. Markets+ Settlements

Bonneville did not receive comments on Markets+ settlements.

6.7. Bonneville Power Services Customer Participation in Markets+

ISSUE 41: Whether Bonneville adequately considered Provider of Choice

Draft Policy Position

Bonneville explained in the Draft Policy that it "coordinated with customers in the Provider of Choice public process to design power products that will be compatible with a day-ahead market for the 2028-2044 contract period."[689] Bonneville stated that participation in a day-ahead market "will be consistent with the obligations of its Provider of Choice power sales contracts." These contracts include the terms and conditions of the products and services that Bonneville offers its power customers and define the obligations of the parties. Bonneville will look to accommodate power customers' participation in the market consistent with the obligations of their product and service elections.[690]

Additionally, Bonneville collaborated with its customers to include contract provisions "to adapt to potential day-ahead markets to ensure the flexibility to meet a changing landscape."[691] Bonneville explained in section 6.7 of the Draft Policy that the Provider of Choice contracts will include a contract provision that requires Bonneville to hold a public process to consider contract amendments necessary to accommodate Bonneville's decision to join a day-ahead market.[692]

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688 Draft Policy at 62.
689 *Id.* at 9.
690 *Id.* at 62.
691 *Id*. at 14.
692 *Id*. at 62.

Public Comments

Bonneville received multiple comments focusing on its decision around a day-ahead market and Provider of Choice timing and implementation. OCGC and PG&E both commented that Bonneville should delay its decision because it is unlikely to go-live in a day-ahead market until 2028. OCGC stated: "BPA has said it will not go live in a DAM before October 2028, when its Provider of Choice contracts go into effect . . . . [H]olding off on a market decision for a matter of months—until October 2025—should not significantly impact the overall timeline."[693] PG&E states: "BPA has indicated it is unlikely to go-live in a DA market until after new Provider of Choice long-term contracts for preference customers are signed, which means implementation is likely in 2029 or later."[694]

AWEC and PPC comment in support of Bonneville's proposed timeline to ensure there is sufficient time to incorporate a day-ahead market decision into the Provider of Choice contracts. AWEC states that "the timing of BPA's decision is appropriate and necessary in order to ensure that other key processes – including Provider of Choice – are reflective of BPA's decision."[695] AWEC encourages Bonneville to make its decision in May 2025 and begin its implementation process to "ensure that BPA's customers have all of the information necessary to inform product choice . . . ."[696]

PPC emphasizes the importance of moving forward with a day-ahead market participation decision in order to "provide important context for ongoing Provider of Choice contract discussions . . . ."[697] PPC states that detailed discussions on implementation issues are needed especially related "to how participation in Markets+ can be incorporated in the Provider of Choice contracts . . ." and to document any details in the ROD to the extent they are already known.[698] PPC states that the day-ahead market participation decision will inform other ongoing processes and Bonneville should "set clear expectations with customers on how it will engage with them on future issues. For example, we would like to see BPA begin its active stakeholder processes to implement the market decision into the provider of choice contracts, as soon as possible following contract execution."[699] PPC emphasizes that: "BPA must ensure capability between the Provider of Choice contracts and Markets+ participation. As the agency implements the Provider of Choice contracts and their delivery through the day-ahead market, BPA must

693 OCGC-040725 at 5.
694 PG&E-040725 at 4.
695 AWEC-040725 at 2.
696 *Id*. at 2-3.
697 PPC-040725 at 2.
698 *Id*. at 7.
699 *Id*. at 20.

ensure that it does so in an equitable manner for all power customers, regardless of product type."[700]

WPAG states that Markets+ better aligns with the draft templates for Provider of Choice contracts. This alignment, WPAG states, "will go a great deal toward ensuring that BPA's participation in a day-ahead market will facilitate rather than hinder its implementation of the [Provider of Choice] Contracts."[701] WPAG cites multiple examples of areas where the Markets+ and Provider of Choice contracts are compatible: (1) both support regional resource adequacy through WRAP, (2) Peak Load Variance Service under the Block with Shaping Capacity product, and (3) GHG accounting. WPAG emphasizes the importance of the GHG accounting design under Markets+ and stated it is "essential for BPA to be able to meet its GHG obligations to customers under Exhibit H of the draft [Provider of Choice] template." WPAG asserts it would not support market participation without the alignment of GHG accounting between the market and the Provider of Choice contract. WPAG states that before Bonneville participates in a day-ahead market, Bonneville must address the "[p]otential amendments to the PoC Contracts as contemplated in Section 23 of the draft templates to facilitate BPA's participation in the selected day-ahead market."[702]

EWEB cautions that implementation of a day-ahead market must consider alignment of the day-ahead market with other processes including Provider of Choice contracts.[703] Similarly, Snohomish encourages Bonneville to begin implementation discussions before the fall.[704]

Multiple commenters explained that by joining a day-ahead market, Bonneville will have opportunities to "optimize generation and transmission resources, improve reliability, enhance price transparency, and ensure cost-effective long-term load service. By selecting Markets+, BPA is demonstrating leadership in the evolution of Western energy markets and aligning with its statutory and contractual obligations."[705] Modern made a similar comment and adds day-ahead market participation will improve the agency's ability to meet it power supply obligation: "BPA's evaluation process demonstrates that joining a day-ahead market will bolster the agency's capability to fulfill its power supply obligations and deliver economic advantages to customers."[706] Pacific similarly states, "BPA's evaluation process shows that participating in a

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[700] *Id.*
[701] WPAG-040725 at 3.
[702] *Id.* at 4.
[703] EWEB-040725 at 2.
[704] Snohomish-040725 at 6-7.
[705] Big Bend-040725 at 1; Cowlitz-040725 at 1; CRPUD-040725 at 1; Hood River-040725 at 1; Lincoln-040425 at 1; Mason-040725 at 1; Pacific-040725 at 1.
[706] Modern-040425 at 1.

day-ahead market will bolster the agency's ability to meet its power supply obligations and provide economic benefits to customers."[707]

RNW expresses concern over Bonneville's ability to implement a new day-ahead market while maintaining its existing functions, such as "BPA's ongoing BP-26 rate case, the new transmission planning reforms, Provider of Choice, Fish and Wildlife and Tribal Programs, Evolving Grid, and the Residential Exchange Program, among others."[708]

Evaluation

Multiple stakeholders commented on the timing of a day-ahead market decision relative to Bonneville's long-term Provider of Choice contracts. Timing considerations are addressed in Issue #13. Bonneville is not persuaded by comments that it should delay a decision toward joining a day-ahead market given the commencement of power deliveries under Bonneville's post-2028 long term power sales contracts (Provider of Choice contracts). Bonneville believes it is reasonable to prepare in advance the practices and mechanisms it will need to interface with a day-ahead market so that Bonneville's obligations to supply electric power pursuant to such power sales contracts are met without any unexpected surprises.

For example, customers must request a contract and make a product election by June 18, 2025.[709] Thereafter, Bonneville will need time to populate individual contract offers with the goal to have contracts signed and executed by the end of December 2025. If Bonneville delayed its policy until after October 2025, customers would be making product elections without knowing the market Bonneville would be pursuing. Under the Provider of Choice draft master template, customers have a one-time right to change their product election subject to certain conditions.[710] The earliest a product change could be effective is October 1, 2032. Bonneville agrees with AWEC and PPC that a May decision to pursue Markets+ would provide important time and context to inform customers' Provider of Choice product election and to align market participation with Provider of Choice contracts.

PPC and EWEB comment that Bonneville must ensure compatibility and alignment between Provider of Choice contracts and the day-ahead market.[711] PPC requests Bonneville to "set clear expectations with customers on how it will engage with them on future issues. For example, we would like to see BPA begin its active stakeholder processes to implement the market decision

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[707] Pacific-040725 at 1.
[708] RNW-040725 at 3.
[709] *See* Bonneville Power Admin., Provider of Choice Timeline (Feb. 20, 2025), *available at* https://www.bpa.gov/energy-and-services/power/provider-of-choice.
[710] The Provider of Choice Draft Master Template is available at https://www.bpa.gov/-/media/Aep/power/provider-of-choice/contract-templates/20250312-poc-master-template.docx.
[711] EWEB-040725 at 2.

into the Provider of Choice contracts, as soon as possible following contract execution."[712] Snohomish commented Bonneville should initiate implementation discussions before the fall in particular for planned product customers that may be "market facing" and "to ensure they are ready to participate in the market at the time of Bonneville's market entry."[713]

Bonneville explained in the Draft Policy that it would host a public process to determine if contract amendments are necessary to implement Bonneville's day-ahead market decision. The Draft Policy recognized this and explained that there would be a provision in the Provider of Choice contracts that will enable the parties to amend contracts to align with Bonneville's decision to join a day-ahead market. Section 6.7 of the Draft Policy states, "Bonneville will hold a public process to review proposed standardized amendment language and offer an opportunity for public comment on that language."[714]

Bonneville agrees with WPAG's comment that before Bonneville participates in a day-ahead market, "BPA must address the [p]otential amendments to the PoC Contracts as contemplated in Section 23 of the draft . . . ."[715] Under Section 23 of the Provider of Choice draft master template,[716] published March 12, 2025, after Bonneville makes a final decision to join a day-ahead market, Bonneville will conduct a public process to discuss "implementation details of Bonneville's decision and work with customers to determine: 1) any necessary amendments to the Provider of Choice power sales agreements, including any that are necessary to align with an updated Transmission Services tariff and settlements under an organized market, and 2) the anticipated timeline for executing such amendments."

Bonneville recognizes there are many implementation details that need to be discussed. The purpose of the Policy is to transparently inform stakeholders about the scope of subsequent actions towards participation such as 1) determining cost allocation in rate proceedings 2) updating tariff terms and conditions in a tariff proceeding and 3) ultimately making a final decision, which would include completing the steps of readiness and go-live in the event of participation. Implementation details related to the Provider of Choice contracts will be discussed through the public process triggered pursuant to the Provider of Choice contracts. Commenters requested Bonneville initiate contract discussions early or as soon as possible after contract execution. Bonneville intends to engage in the contract amendment process with Provider of Choice customers as soon as a decision to join a day-ahead market is made. Prior to the contract amendment process, Bonneville may begin preliminary implementation discussions

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[712] PPC-040725 at 20.
[713] Snohomish-040725 at 6-7.
[714] Draft Policy at 62.
[715] WPAG-040725 at 4.
[716] The Provider of Choice Draft Master Template is available at https://www.bpa.gov/-/media/Aep/power/provider-of-choice/contract-templates/20250312-poc-master-template.docx.

if it determines that early engagement would be useful. Then, after Bonneville takes steps to become a participant in a day-ahead market, Bonneville and customers would finalize and execute day-ahead market Provider of Choice contract amendments.

RNW expressed concern over Bonneville's ability to implement a new day-ahead market while maintaining its existing functions.[717] Bonneville agrees it has many important initiatives and functions that it must fulfill and a major initiative such as day-ahead market participation will need adequate staffing and resources to implement alongside existing initiatives. While implementation will require dedicated resources, alignment between the day-ahead market and many of these existing initiatives must occur. For example, multiple commenters noted their support for Bonneville's future participation in a day-ahead market as it would provide opportunities to "optimize generation and transmission resources, improve reliability, enhance price transparency, and ensure cost-effective long-term load service."[718] Bonneville agrees there are many opportunities that a day-ahead market will present that are likely to complement Bonneville's existing initiatives and functions. For this reason, day-ahead market implementation planning will be critical. Bonneville has not identified a go-live date for participation but rather, Bonneville would determine the appropriate go-live date through future implementation planning to ensure resources will be available to implement a day-ahead market decision across various agency initiatives.

Finally, Bonneville appreciates comments from WPAG and Tacoma that highlight how Markets+ is compatible with the Provider of Choice contracts. WPAG commented that key commonalities between Markets+ and the Provider of Choice contracts include support for regional resource adequacy and design of GHG accounting.[719] Bonneville agrees that Markets+ appears to align closely with the Provider of Choice contract obligations. Tacoma expressed appreciation of Bonneville's consideration of product offerings relative to a day-ahead market. Tacoma stated, "In January of 2024 Tacoma submitted comments stating that as BPA considers day-ahead market options, BPA must also serve its customers with products that will enable its customers to be successful participants in that market. We appreciate that BPA has focused on that necessity. BPA's decision to join Markets+ reflects that continued commitment to the needs of its customers."[720]

Decision

Bonneville adequately considered Provider of Choice and other important agency initiatives in the Final Policy.

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[717] RNW-040725 at 3.
[718] Big Bend-040725 at 1; Cowlitz-040725 at 1; CRPUD-040725 at 1; Hood River-040425 at 1; Lincoln-040425 at 1; Mason-040725 at 1; Pacific-040725 at 1.
[719] WPAG-040725 at 3-4.
[720] Tacoma-040225 at 6-8.

ISSUE 42: Whether Bonneville would sell power outside of the Western Interconnection

Draft Policy Position

Bonneville described the evolution of energy markets in the Western Interconnection as well as the proposed footprint of Markets+ in Section 2.2 of the Policy.

Public Comments

Several comments express concern that Bonneville would be sending low-cost power generated in the Pacific Northwest to Arkansas or other entities outside the Western Interconnection.[721]

Evaluation

It is important to clarify the footprint of Markets+ and the role of SPP. The Markets+ footprint will be entirely in the *Western Interconnection*, meaning all generation and load (energy demand) is located in the West.[722] No energy will flow from the Pacific Northwest to Arkansas as a result of Markets+ optimization. The Western Interconnection is geographically separated from and not synchronously connected to other regions, meaning that there is no inadvertent flow out of the Western Interconnection. The footprint of Markets+ is limited to the Western Interconnection and does not include any generation or load in SPP's eastern RTO footprint or SPP's proposed RTO West footprint.

SPP is the Markets+ market operator, meaning it will provide services and run the market solution algorithm based on data submitted by Western entities participating in Markets+. Neither SPP nor any participant in another SPP-operated market will have generation or load in Markets+. While SPP operates other markets, the Markets+ market run will not include co-optimization with SPP's eastern RTO footprint, its Western Energy Imbalance Service footprint, or its proposed RTO West footprint.

Decision

Bonneville will not sell power outside of the Western Interconnection.

6.8. Bonneville Transmission Services Customer Participation in Markets+

[721] Jacobson-031725 at 1; Harter-031825 at 1; Richman-031125 at 1; Nason-030225 at 1.
[722] Policy § 2.2.

ISSUE 43: Whether participation would affect transmission customer use of existing transmission rights

Draft Policy Position

Bonneville discussed the potential impacts to transmission customers in Section 6.8 of the Draft Policy.

In the Draft Policy, Bonneville concluded that it is anticipating some changes in how its customers may utilize their Bonneville transmission rights. Bonneville transmission contract holders will still have the ability to exercise their transmission rights . . . .".[723] Bonneville will need to address necessary tariff changes for implementation. Bonneville will discuss potential tariff changes through the tariff process. Bonneville may also need to update its business practices for implementation and will do so through the established business practice process.[724]

Public Comments

NIPPC comments that Bonneville "does not discuss the differences between the two market designs or address the different implications each market will have on transmission customers."[725] NIPPC submits multiple questions about the implications of joining Markets+ on customers' use of transmission rights both prior to and after the day-ahead market run.[726] While NIPPC acknowledges "some of these questions can be definitively answered only in a rate setting or tariff revision process," it believes that answers will "provide valuable insights to both BPA and its customers in reaching a decision about which market BPA should join."[727]

Evaluation

As stated in the Policy, "Bonneville transmission contract holders will still have the ability to exercise their transmission rights . . . consistent with Bonneville's tariff, business practices, and any other relevant agreements as they do today during the day-ahead and real-time horizons, though there may be different implications of doing so."[728] Bonneville also provided an overview of how transmission may work in Markets+ at a public workshop on July 18, 2024.[729]

Currently, Bonneville does not have any more information to share. Most detailed questions will need to be answered during implementation, and as NIPPC acknowledges, cannot be finalized until tariff changes are proposed through a tariff terms and conditions proceeding.

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[723] Draft Policy at 63.
[724] *Id.* at 65.
[725] NIPPC-040725 at 13-14.
[726] NIPPC-040725 at 14.
[727] *Id.* at 14-15.
[728] Policy at 67.
[729] *Id.* at 67-68.

Decision

Bonneville will work with customers to provide more detail on how transmission will be used during the implementation of Markets+, leading to proposed changes through a tariff terms and conditions proceeding.

ISSUE 44: Whether participation would have disparate impacts on Network Integration Transmission Service (NITS) customers

Draft Policy Position

Bonneville discussed transmission customer participation in section 6.8 of the Draft Policy and the congestion rent design and allocation methodology in section 5.2.4 of the Draft Policy.

In the Draft Policy, Bonneville concluded that it is "anticipating some changes in how its customers may utilize their Bonneville transmission rights. Bonneville transmission contract holders will still have the ability to exercise their transmission rights . . . ."[730] Also "[i]n Markets+, congestion rents associated with physical constraints are allocated directly and proportionally to the transmission rights holders of firm and conditional firm PTP transmission service, network integration transmission service, and legacy transmission service of monthly or longer service increments whose rights are associated with that physical path . . . ."[731]

Public Comments

A number of commenters raise concerns about the lack of a direct distribution of congestion revenue to NITS customers relying on secondary NITS or priority 6 transmission for load service. NRU, WPAG, and Umatilla express concern regarding the treatment of secondary NITS. NRU states a concern regarding SPP's allocation of congestion rent to firm and conditional firm Point-to-Point (PTP) without a similar allocation to NITS and secondary NITS. NRU highlights that Bonneville Transmission staff have recently expressed consideration of re-creating a conditional firm NITS product due to an inability to ensure firm capacity for NITS customers.[732] WPAG similarly suggests that Bonneville create a conditional firm NITS product to enable congestion revenue allocations to NITS customers that must rely on secondary NITS due to a lack of transmission capacity.[733] Umatilla echoes these concerns and suggests that Bonneville

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[730] Draft Policy at 63.
[731] *Id.* at 48.
[732] NRU-040725 at 4-5.
[733] WPAG-040725 at 5.

continue to work to address this issue. NRU asks specifically that Bonneville commit to working with NITS customers in advance of market implementation.[734]

PPC states, "[i]t will be critical that a holistic review of these implementation details occurs between BPA and its customers. The questions asked about how congestion revenue applies to various aspects of NT service and how congestion collected by BPA will be allocated to full requirements NT customers is an excellent example of why a timely a holistic approach to these discussions is so important."[735]

Evaluation

Bonneville acknowledges and understands the concerns raised by NRU, WPAG, and Umatilla. The concerns raised relate to the Markets+ design, which has been approved by FERC as just and reasonable.[736] Under the Markets+ tariff, if an entity is a registered Market Participant, the Market Operator will distribute congestion revenue directly to PTP transmission rights holders if they hold firm or conditional firm (CF) service for a month or longer. While firm PTP relies on priority 7 transmission, if CF service has not been firmed up, it relies on priority 6 transmission. As CF can only be acquired through a request for long-term firm PTP, this aspect of the market design is intended to incentivize entities to request and retain long-term service.

Similarly, as for PTP customers, if a NITS customer is a registered Market Participant, it is eligible for direct settlements through Markets+. For NITS customers who are not registered Market Participants and for whom Bonneville Power Services is the market participant on their behalf, SPP will distribute congestion revenue directly to Bonneville Power Services. The allocation cap is based on the customers' monthly peak load and the allocation across paths is based on the designated network resources offered to serve their loads.[737] However, if NITS customers use secondary NITS service (priority 6), they will not receive direct congestion rent allocation as the Markets+ design does not include secondary service in the direct congestion rent allocation.

NITS customers use secondary service for market purchases from non-designated network resources or in instances where there is insufficient transmission capacity for the resource designation. Bonneville Power Services also uses secondary NITS to take advantage of market purchases from non-designated resources. In these cases, there may be congestion revenue, but SPP will not allocate it directly to the Market Participant. SPP will allocate any undistributed congestion revenue to the TSP, and the TSP must determine how to allocate the congestion

[734] Umatilla-040725 at 2.
[735] PPC-040725 at 20.
[736] *SPP*, 190 FERC ¶ 61,030 (Jan. 16, 2025).
[737] Markets+ Tariff, Attach. A § 7.16 (Congestion Rent Eligible Transmission Service Reservation).

revenue to its customers.[738] Bonneville intends to address these issues in a future rate proceeding undertaken pursuant to Section 7(i) of the Northwest Power Act.[739]

In addition, the inclusion and potential impacts of PTP CF will be monitored by the Markets+ stakeholders and evaluated for potential changes in the future, which may result in updates to the Markets+ design, if appropriate.[740]

With respect to transmission capacity constraints, Bonneville intends to work with customers as part of its Transmission Planning Reform initiative. While new large NITS loads continue to pose issues, these issues impact a very small subset of customers. For most NITS customers, Bonneville has planned for and can accommodate trended load growth.

Both NRU and WPAG raise the concept of a NITS CF product. Bonneville removed the NITS CF product from its tariff in 2020 because NITS customers already have the flexibility that is otherwise afforded by the PTP CF product: for example, firm transmission does not need to be available 100% of the time for a NITS customer to designate a network resource.

For the handful of NITS customers that are forecasting large load increases, Bonneville will continue to work toward resolution in the Transmission Planning Reform initiative.

Decision

Bonneville does not expect disparate impacts to NITS customers, and it commits to engage with all customers regarding the treatment of excess congestion revenue and other rates-related issues prior to market implementation.

ISSUE 45: Whether the Markets+ design allowing transmission opt-outs is beneficial for transmission customers

Draft Policy Position

Bonneville discussed transmission opt-outs in Section 6.8 of the Draft Policy.

In the Draft Policy, Bonneville acknowledged that "Markets+ permits transmission customers to 'opt out' their transmission rights according to the market rules."[741] "Bonneville transmission contract holders that want to participate in another market (e.g., EDAM) may want to 'opt out'

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[738] *Id.*, Attach. A § 9.2.15 (Day-Ahead Excess Congestion Rent Allocation Distribution Amount).
[739] 16 U.S.C. § 839e(i).
[740] SPP, Markets+ Monitoring Metrics Congestion Rent (Aug. 14, 2024), *available at*: https://www.spp.org/Documents/72193/Congestion%20Rent%20Monitoring%20Approach%20Clean.docx.
[741] Draft Policy at 64.

transmission from Markets+ so that generation in that market can be optimized across that transmission."[742] Bonneville also noted that "opting out transmission is not required in order to (a) self-schedule or (b) individually transact outside of the Markets+ footprint."[743]

Public Comments

PG&E disagrees with Bonneville's conclusion that transmission design of EDAM and Markets+ are similar.[744] Specifically, PG&E states "there is no method of excluding transmission capability from EDAM" and that the ability to opt-out transmission in Markets+ may lead to "the potential for economic withholding[.]"[745] According to PG&E, this could lead market participants to (i) "opt-out transmission to create artificial shortage"; (ii) game the market by "opt[ing]-out certain transmission paths to force the Markets+ optimization to rely on resources owned by that same entity to advantage itself in the market"; and (iii) maximize congestion rent revenues "by withholding certain transmission paths."[746] Ultimately, PG&E concludes that joining EDAM is the only solution.[747]

SCL comments that joining Markets+ will create seams and "[f]urther transmission opt-outs . . . may cause the market(s) to be commercially constrained even though the transmission system is not physically overloaded."[748]

Snohomish supports the design of Markets+ that allows for opt-outs of transmission. Snohomish states the "Markets+ tariff explicitly supports interoperability with neighboring markets through the provision of opt outs (the ability to carve transmission rights out of Markets+ for other purposes, such as EDAM) and opt ins (the ability to use rights on non-participating systems to connect the footprint)."[749]

Evaluation

As described in the Draft Policy, the Markets+ design "permits transmission customers to 'opt-out' their transmission rights . . . ."[750] As Snohomish acknowledges, this allows Bonneville transmission customers to participate in other markets, such as EDAM. Without such a feature, Bonneville transmission customers would not be able to participate in their market of choice.

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[742] *Id.*
[743] *Id.*
[744] PG&E-040725 at 2.
[745] *Id.*
[746] *Id.* at 3.
[747] *Id.*
[748] SCL-040725 at 21.
[749] Snohomish-040725 at 4.
[750] Draft Policy at 68.

Bonneville views this feature as a benefit. In contrast, PG&E argues that joining Markets+ may lead to various forms of market manipulation and that EDAM is the only solution. First, PG&E's arguments are misplaced; Bonneville notes as a threshold matter that Markets+ was determined to be just and reasonable by FERC. Second, not only are there timing requirements that would make gaming impractical (minimum duration of one month, inability to communicate opt-outs more than once a month, and communication of opt-outs at least 15 calendar days in advance of the upcoming calendar month),[751] but the Markets+ design provides for a market monitor specifically aimed at curbing such behavior.[752] PG&E's conclusion that EDAM is the only solution is incorrect. Nevertheless, Bonneville has updated Section 6.8 of the Policy to note the role of market monitor to prevent unlawful withholding of transmission by market participants.

Bonneville also disagrees with PG&E that EDAM does not allow for the exclusion of transmission capability from EDAM. Section 33.18.33 of CAISO's tariff provides:

> **33.18.33 Transmission Not Available in the Day-Ahead Market.** If the CAISO is informed through the prospective EDAM Entity implementation process or by the EDAM Entity Scheduling Coordinator for the EDAM Transmission Service Provider that accommodation of incremental intra-day schedules in the Real-Time Market should be unavailable in the Day-Ahead Market according to the EDAM Transmission Service Provider tariff, the CAISO will accept a notification from the EDAM Entity Scheduling Coordinator associated with the EDAM Transmission Service Provider and will adjust Day-Ahead Market availability of the impacted transmission elements and the associated transmission service rights.[753]

In its transmittal letter, CAISO stated that "if a balancing authority informs the CAISO through the implementation process, or anytime following its participation in EDAM, that transmission availability should be restricted in the day-ahead market to accommodate the exercise of transmission customer rights, the CAISO will adjust day-ahead market transmission availability of the affected transmission elements."[754] Thus, EDAM specifically allows each TSP to carve out transmission to allow for the exercise of transmission rights on the TSP's system.

While Bonneville acknowledges SCL's concern about creating additional market seams, as stated above, such a feature is necessary to allow multiple markets to work together. Bonneville and all other parties will need to work collaboratively to mitigate all seams issues that may be created by the intersection of multiple day-ahead markets.

Decision

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[751] Markets+ Tariff, Attach. D § 1.2 (Obligation to Communicate Markets+ Transmission Capacity Availability Changes).
[752] Markets+ Tariff, Attach. C § 4.5 (Monitoring for Potential Transmission Market Power Activities).
[753] CAISO, FERC Docket No. ER23-2686, Transmittal Letter, Attachment A-2, Tariff § 33.18.3.3 (Aug. 23, 2023).
[754] *Id.* at 135.

Bonneville concludes that the Markets+ design allowing transmission opt-outs is necessary to allow for interoperability of multiple day-ahead markets.

7. NEPA & Environmental Obligations

ISSUE 46: Whether Bonneville properly and adequately conducted its environmental review of its day-ahead markets policy

Draft Policy Position

Consistent with NEPA, Bonneville assessed the potential environmental effects that could result from its proposal to adopt a policy direction to take steps to facilitate participation in SPP's Markets+ in Section 7 of the Draft Policy.

Public Comments

Comments from NWEC, Idaho Conservation League (ICL), Earthjustice, OCGC, the Sierra Club, RNW, ATNI, CTUIR, and Yakama Nation assert that Bonneville has failed to conduct an adequate environmental review process under NEPA and/or consultation under the Endangered Species Act in connection with Bonneville's proposed adoption of this Policy.[755] With respect to NEPA compliance, a joint comment letter from NWEC, ICL and Earthjustice asserts, as an initial matter, that Bonneville "has made an irreversible commitment of resources to Markets+ before it has conducted any NEPA analysis for that commitment or a decision to join Markets+" by "signing the binding Markets+ Funding Agreement and providing a binding letter of assurances of up to $40,000,000 as part of the collateral for a bank loan to support the development of Markets+."[756] The joint comment letter further asserts that Bonneville's adoption of the Policy would "fail to consider the environmental impacts of joining Markets+," including "changes in the normal operating range of . . . generating resources by more than 50 average MW" resulting from the potential replacement and retirement of the Lower Snake River Dams, which NWEC, ICL and Earthjustice assert would follow from Bonneville's increased access to sufficiently large quantities of "cheap low-cost renewable power" via participation in a day-ahead market.[757]

Separate comment letters from CTUIR and Yakama Nation echo this latter point, each asserting that Bonneville's adoption of the Policy entails "a contract for the acquisition of new power resources larger than 50 average megawatts and is likely to change operations at more than 50 aMW of existing federal resources," triggering the need for NEPA review, including preparation of an EIS, and precluding invocation of a categorical exclusion.[758] Additional comment letters

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[755] Bonneville also received many comments from the public regarding other environmental impacts; *see* Hanken-Follett-031725; Hughes-040325; Rasmussen-031725 (raising wildfire impacts).
[756] Earthjustice-040725 at 2.
[757] *Id.* at 13.
[758] CTUIR-040725 at 9-10; Yakama-040325 at 7.

from OCGC, the Sierra Club, RNW, and ATNI, respectively, assert that NEPA requires Bonneville to analyze various potential environmental impacts of day-ahead market participation, including:

- Impacts resulting from "fundamental[]changes in how electricity is sourced and dispatched across the region";[759]
- "emissions, conventional air pollution releases and many on the ground impacts";[760]
- impacts on "resource mix," impacts caused by "transmission system change"—including the possibility of "additional transmission across federal land"—and "impacts to low-income ratepayers and environmental justice communities related to the addition of new markets seams";[761]
- impacts to "aquatic ecosystems, including habitats critical to anadromous species such as salmon and steelhead."[762]

OCGC also questions whether Bonneville "has . . . satisfied NEPA's requirements" to "solicit comments from interested and affected parties" as part of its assessment of potential environmental impacts of adopting the Policy.[763]

With respect to ESA compliance, comment letters from CTUIR and Yakama Nation assert that "[j]oining a day-ahead market could have impacts that could jeopardize the continuing existence of a threatened or endangered species under the Endangered Species Act," obligating Bonneville and other action agencies such as the BOR and the USACE to "prepare a biological assessment and biological opinion on the effects of its decision."[764]

Evaluation

Bonneville appreciates the comments of many interested parties and stakeholders regarding Bonneville's environmental review of its proposed adoption of the Policy. In section 7 of the Draft Policy, Bonneville indicated that, although it was still in the process of assessing the potential environmental effects that could result from participation in a day-ahead market, such participation was likely the type of action typically excluded from further review pursuant to DOE NEPA regulations, which apply to Bonneville.[765] In contrast to a final agency decision to join Markets+, this policy establishes the scope for future implementation decisions, and sets a direction to enable Bonneville's participation by determining cost allocation in rate proceedings and updating tariff terms and conditions in a tariff proceeding. These steps would precede a final

[759] OCGC-040725 at 12.
[760] Sierra Club-040725 at 3.
[761] RNW-040725 at 23.
[762] ATNI-040725 at 1.
[763] OCGC-040725 at 12.
[764] CTUIR-040725 at 9-10; Yakama-040325 at 7.
[765] Draft Policy § 7 (NEPA & Environmental Obligations).

agency decision to join Markets+ and would not entail any action by Bonneville that would have a potential effect on the environment. Bonneville will conduct and document any appropriate NEPA analysis prior to taking additional steps towards—or making any final agency decisions with respect to—joining and participating in Markets+. Bonneville retains its authority and discretion over any future decision to join or participate in a market.

For the same reason, Bonneville has not—as NWEC, ICL and Earthjustice assert—already decided the matter of its participation in Markets+ merely by agreeing to fund development of the market.[766] Bonneville's prior decision to fund market development did not obligate Bonneville to actually join or otherwise participate in Markets+, and Bonneville would conduct and document appropriate additional NEPA analysis prior to making that decision. As stated above, the decision to adopt this policy direction to participate in a day ahead market similarly does not obligate Bonneville to join the market. Accordingly, the proper scope of environmental review extends only to the administrative and procedural actions that would be undertaken pursuant to the proposed Policy direction.

Merely adopting a Policy direction would not have any environmental effects, including, but not limited to, the various asserted impacts of concern to OCGC, the Sierra Club, RNW, and ATNI. Specifically, Bonneville's proposed Policy direction here—to facilitate its potential entrance into Markets+—would not implement FCRPS operations or management actions. Operational decisions would continue to be subject to applicable NEPA and ESA documents, including the annual operating documents such as the Water Management Plan and Fish Passage Plan, and this Policy direction would not alter the boundaries for such operations without additional environmental compliance on associated operations and management decisions. Thus, a decision to adopt the proposed Policy direction is not expected to have environmental effects, including impacts on ESA-listed species and/or their designated critical habitat of concern to CTUIR and Yakama Nation.

Decision

Bonneville determines that setting a Policy direction to pursue joining Markets+ is not expected to result in any environmental impacts requiring analysis and documentation pursuant to DOE NEPA regulations, which are applicable to Bonneville. The Policy does not obligate Bonneville to join Markets+; a final decision on whether to join would be made by Bonneville at a later date. Appropriate additional NEPA analysis and documentation would be conducted prior to making that final agency decision.

[766] Earthjustice-040725 at 2.

All public comments concerning environmental compliance for this proposal that Bonneville received during the stakeholder discussions will continue to be considered during the environmental review process.

ISSUE 47: Whether Bonneville should assess Fish and Wildlife Mitigation Funding in the Policy

Draft Policy Proposal

Bonneville does not address fish and wildlife mitigation funding in the Draft Policy.

Public Comments

CRITFC questions whether the additional implementation costs associated with Markets+ would impact Bonneville's fish and wildlife budget.[767] CTUIR further suggests that funds for implementation could alternatively be spent on fish and wildlife or rate reduction.[768]

Evaluation

Bonneville's fish and wildlife program addresses certain mitigation responsibilities under the Northwest Power Act and the ESA. The budget for Bonneville's programs, including its fish and wildlife program, are developed through other processes. Bonneville recovers all of its costs, including the costs for implementing its fish and wildlife program, through rates.

Decision

Bonneville's fish and wildlife funding is outside the scope of this Policy. To the extent that this comment suggests Bonneville might reduce fish and wildlife funding in order to offset market implementation costs, Bonneville has no such intention.

8. Tribal Obligations

ISSUE 48: Whether the Policy should address tribal treaty and trust obligations

Draft Policy Proposal

Bonneville did not address tribal treaty and trust obligations in the Draft Policy.

Public Comments

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[767] CRITFC-040725 at 3.
[768] CTUIR-040725 at 11; Yakama-040325 at 12.

Commenters raise concerns regarding the federal government's trust and treaty responsibility. The Snoqualmie Tribe and Makah Tribe comment: "The federal government's trust responsibility obligates BPA to ensure that Tribes are full partners in managing the lands and resources that are our ancestral inheritance."[769]

OCGC comment: "As a federal agency, BPA has a legal and fiduciary obligation to fulfill its Federal trust responsibilities to Tribes, and BPA's DAM decision implicates *several* Tribal resources and rights in the region (including dam operation and fisheries).[770] Bonneville's Draft Policy makes zero references to Tribes, or to any research or analyses it may have conducted in order to understand how its DAM decision may or may not affect the resources and rights of Tribes in our region. This is a glaring oversight."[771]

Multiple commenters state that Bonneville's plans to join Markets+ would "violate federal trust responsibility—shutting out Tribal voices in key energy decisions . . . ."[772] Similarly, one commenter stated that joining Markets+ would "[v]iolate federal trust obligations to Tribes across the Columbia-Snake River Basin by shutting out tribal participation in major energy decisions.[773] Another commenter states that Markets+ could "exclude Tribal Nations from key decisions—violating federal trust responsibilities.[774] Others made similar comments: "I don't want to see . . . Tribes shut out of the policy decision making process . . . ,"[775] and "Please do not join Markets+. It would . . . shut out Tribal voices . . . ."[776] "Please do not commit to the risky Markets+ energy relationship that will . . . negatively impact tribal rights, salmon and our environment . . . ."[777]

Other commenters request for Bonneville to "honor our treaties our native neighbors . . . ."[778] and "honor treaty rights and protections that other non-regional players are not dealing with."[779]

Evaluation

Multiple commenters raised concern that Bonneville's participation in Markets+ would violate federal trust obligations. Bonneville does not have a specific trust obligation. As a federal agency, without a specific trust or treaty obligation, Bonneville has a general trust responsibility.

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769 Snoqualmie-040725 at 1; Makah-040725 at 1.
770 OCGC-040725 at 11.
771 *Id*.
772 CSRC at 1.
773 *Id*.
774 Brewer-040725 at 1.
775 Moen-040325 at 1.
776 CSRC at 1.
777 *Id*.
778 Rutherford-040725 at 1.
779 Miller-040325 at 1.

Bonneville recognizes the "undisputed existence of a general trust relationship between the United States and the Indian people."[780] Bonneville also recognizes that it shares in this general trust responsibility and remains committed to fulfilling such responsibility. While there is a "distinctive obligation of trust incumbent upon the Government in its dealings with [Indian tribes]," that alone "does not impose a duty on the government to take action beyond complying with generally applicable statutes and regulations."[781]

Bonneville fulfills its treaty and trust responsibilities by working with the Pacific Northwest tribes in accordance with Bonneville's Tribal Policy. Bonneville also fulfills its responsibility by complying with laws governing Bonneville's activities, including but not limited to the Northwest Power Act, the American Indian Religious Freedom Act (as amended), the Native American Graves Protection and Repatriation Act, the Native American Free Exercise of Religion Act, the National Historic Preservation Act, and the Archaeological Resources Protection Act. Bonneville's Tribal Policy is consistent with its statutory and contractual obligations. As stated above, Bonneville's day-ahead market Policy sets the policy direction for Bonneville's future participation in a day-ahead market. The Policy neither impacts nor changes Bonneville's ability to meet obligations under existing laws and contracts, including FCRPS operations, river management, or fish and wildlife mitigation. Operational non-power obligations will continue to be met consistently with such obligations, as referenced above in Section 6.1, Section 8, and Appendix A of the Policy.

Decision

While Bonneville has not identified any provision in the Policy that would directly affect tribal resources that are held in trust by the federal government, Bonneville has updated the Policy to reflect that it has considered tribal treaty and trust obligations.

ISSUE 49: Whether the Policy should address tribal engagement and consultation

Draft Policy Proposal

In section 3 of the Draft Policy, Bonneville outlined the extensive public process that Bonneville has conducted from July 2023 through the publication of the Draft Policy in March 2025. During this time, Bonneville engaged its regional stakeholders in an extensive and transparent public process involving customers and interested parties.

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[780] *United States v. Mitchell*, 463 U.S. 206, 225 (1983).
[781] *Gros Ventre Tribe v. United States*, 469 F.3d 801, 810 (9th Cir. 2006).

Public Comments

CTUIR, Yakama Nation, Makah Tribe, Snoqualmie Tribe and Central Council of the Tlingit & Haida request Bonneville engage in direct government-to-government consultation.[782] CTUIR requests consultation so that "BPA fully understands our concerns" and all parties are assured "that joining the Market will not negatively impact the Treaty-reserved resources and rights of the CTUIR or any other Columbia River Treaty Tribe (CTUIR, Confederated Tribes and Bands of the Yakama Nation, Confederated Tribes of the Warm Springs Reservation of Oregon, the Nez Perce Tribe)."[783]

CTUIR comments: "[a] decision by BPA to move forward with Market participation without government-to-government consultation with the CTUIR raises serious concerns about BPA's fulfillment of its trust responsibilities."[784] The Yakama Nation and Umatilla explain "BPA's approach to consultation on this matter has not met the standard of meaningful, government-to-government engagement. The offer of a 'Question & Answer' session with Columbia River Basin Tribes does not constitute sufficient consultation."[785] Finally, Yakama Nation and CTUIR both include a list of issues they would like to address through consultation and conclude they are "committed to engaging in meaningful collaboration with BPA to address these concerns and ensure that all decisions align with . . . Treaty obligations."[786]

The Snoqualmie Tribe comment "Tribal values, priorities, and rights must be integrated into the DAM. The Snoqualmie Tribe respectfully call on BPA to provide proactive government to government consultation."[787] The Makah Tribe state: "BPA has not consulted with the Makah Tribe regarding this rate change" and "[t]his lack of consultation is a serious oversight." They request Bonneville integrate "Tribal values, priorities, and rights" into the day-ahead Market framework" and "provide proactive, meaningful, and timely government-to-government consultation."[788]

The Central Council of the Tlingit & Haida comment that "government-to-government consultation is essential whenever BPA takes action that affects Tribal rights."[789] The Central Council of the Tlingit & Haida request Bonneville to "fully integrate Tribal values, priorities, and

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782 Yakama-040325 at 1; CTUIR-040725 at 1; Snoqualmie-040725 at 1; Makah-040725 at 1; Tlingit & Haida-040425 at 1.
783 CTUIR-040725 at 1.
784 *Id* at 2.
785 Yakama-040325 at 1; CTUIR-040725 at 2.
786 *Id*.
787 Snoqualmie-040725 at 1.
788 Makah-040725 at 1.
789 Tlingit & Haida-040425 at 1.

rights into any day- ahead market planning and to ensure that Tribes are proactively informed and consulted."[790]

In addition to tribes, multiple organizations request BPA to engage in government-to-government consultation. CRITFC commented, "[g]overnment-to-government consultation assures that tribes are adequately informed of any proposal and allows for exchange of concerns. Without it, BPA cannot assure that it is adequately assessing all tribal concerns and interests and assuring tribal rights. Public, open meetings do not constitute government-to- government consultation."[791]

ATNI comment: "it remains unclear whether Tribes with treaty and other protected rights have been adequately informed or meaningfully consulted regarding this consequential decision and its impacts**.** ATNI urges BPA to prioritize Tribal consultation leading to free, prior, and informed consent."[792] ATNI asks Bonneville two questions related to consultation: (1) "To what extent and with which mediums has BPA conducted proactive outreach and engagement with Tribes in Washington, Oregon, Idaho, Montana, Nevada, and California, concerning the Day-Ahead Market decision and its implications?" and (2) "To what extent has BPA conducted timely, meaningful consultation with Tribes in Washington, Oregon, Idaho, Montana, Nevada, and California, concerning the Day-Ahead Market decision and its implications?"[793] ATNI expresses a willingness to "work collaboratively with BPA to ensure Tribal Nations are meaningfully engaged in this critical decision-making process."[794] NWEC and NRDC comment in support of the Yakama Nation and ATNI's comments.

ATNI also submits in the day-ahead market formal comment period a letter to Bonneville dated November 15, 2024. The letter expresses similar concerns and urged Bonneville "to proactively engage in formal government-to-government consultation with affected Tribes on the day-ahead markets decision." The letter quoted ATNI Resolution #24-35 that calls for "free, prior, and informed consent of transmission planning processes at every level to ensure that Tribal electric utilities, Tribal energy development organizations, and Tribal governments have decision- making authority, oversight, and leadership roles in planning of new transmission buildout . . ."[795]

The Alliance for Tribal Clean Energy (ATCE) state "[t]here has been a failure to proactively share information and engage in meaningful dialogue with Tribes regarding these potential impacts, hindering informed decision-making."[796] ATCE continue "BPA's expectation for Tribes

[790] *Id*.
[791] CRITFC-040725 at 2-3.
[792] ATNI-040725 at 1.
[793] *Id* at 2.
[794] *Id*.
[795] ATNI-032425 at 1.
[796] ATCE-040725 at 1

to initiate consultation places an undue burden on Tribal governments and does not align with the principles of the federal trust responsibility. Inadequate Information Sharing: Without detailed data on potential impacts, Tribes cannot provide informed consent, violating their sovereign rights."[797] ATCE recommend "BPA should engage in co-stewardship and co-decision making with Tribes" and urged BPA to "prioritize comprehensive Tribal consultation and informed consent in its decision-making processes regarding day-ahead market participation."[798]

OCGC comment: "BPA has not conducted comprehensive government-to-government Tribal consultation on its DAM decision. BPA's Draft Policy makes zero references to Tribes, or to any research or analyses it may have conducted in order to understand how its DAM decision may or may not affect the resources and rights of Tribes in our region. This is a glaring oversight."[799]

OCGC questions if Bonneville has "upheld its Federal trust responsibility to Tribes through comprehensive government-to-government consultation on this decision?"[800] They also ask whether Bonneville has "conducted any research or analyses on how its DAM decision will or will not affect the resources or rights of Tribes in our region?"[801] One comment notes: "BPA must prioritize transparency, Tribal consultation, and the long-term interests of the Northwest."[802]

Evaluation

The Yakama Nation, Makah Tribe, Snoqualmie Tribe and Central Council of the Tlingit & Haida requested formal government-to-government consultation with Bonneville. Bonneville welcomes these requests to engage in formal consultation and will reach out to these requesting tribes to set up meetings to discuss their concerns.

In addition to the tribal requests for formal consultation, Bonneville received numerous other comments on the topic of consultation.[803] Bonneville recognizes the unique government-to-government relationship the agency has with federally recognized tribes within Bonneville's service territory. Bonneville has a Tribal Affairs organization that provides outreach and

[797] *Id* at 2.
[798] *Id*.
[799] OCGC-040725 at 11.
[800] *Id*. at 13.
[801] *Id*.
[802] Brewer-040725 at 1.
[803] Multiple commenters stated that tribal consultation is necessary for tribes to have "free, prior, and informed consent" (FPIC) of Bonneville's decisions. *See, e.g.*, ATNI-040725 at 1. ATCE similarly recommended "BPA should engage in . . . co-decision making with Tribes" and urged Bonneville to "prioritize comprehensive Tribal consultation and informed consent in its decision-making processes regarding day-ahead market participation." ATCE-040725 at 2. Bonneville notes the FPIC standard is not applicable, and Bonneville is under no obligation to obtain consent from any entity, including tribes ahead of a decision to join a day-ahead market.

communicates with tribes regarding Bonneville programs, projects, and initiatives. Bonneville meets with tribes in formal and informal settings and strives to proactively address tribal concerns. For example, Bonneville meets with tribes on specific projects during NEPA processes, or specifically consults with tribes as part of its obligations under National Historic Preservation Act section 106 processes. Bonneville's Tribal Policy also outlines when the agency will seek formal consultation with tribal governments.

Under the Tribal Policy, Bonneville will engage in formal consultation whenever requested by a tribe. In addition, Bonneville will proactively seek consultation when a Bonneville action may affect tribes or their resources. In this instance, Bonneville did not seek formal consultation with tribes because the Policy decision does not impact tribes or their resources. Primarily, the Policy is a decision on a policy direction, it is not a binding implementation decision to join Markets+. Bonneville's final decision to join Markets+ will be made in the future after the conclusion of subsequent public processes for rates and tariff terms and conditions. Equally as important, participation in a day-ahead market will not alter or impact Bonneville's obligations under existing laws and contracts, including FCRPS operations, river management, or fish and wildlife mitigation. As noted above, Bonneville has received and responded to requests for formal government-to-government consultation and Bonneville will engage with these tribes, and any other tribes that request consultation to discuss the Policy direction decision and potential future market participation. Bonneville anticipates formal consultation with requesting tribes will occur ahead of its final decision to join a day-ahead market.

In its comments, ATNI asked "to what extent and with which mediums has BPA conducted proactive outreach and engagement with Tribes in Washington, Oregon, Idaho, Montana, Nevada, and California, concerning the Day-Ahead Market decision and its implications?" Bonneville has held an open and inclusive process to explore day-ahead market participation that included 11 public workshops available on Webex and in-person. Bonneville's Tribal Affairs group also sought engagement with tribes and ATNI by sending out communications to tribes on workshops and comment periods, and when given the opportunity, Bonneville has made announcements at the ATNI Energy Committee. Bonneville also offered to provide a Q&A session for ATNI.

Decision

Bonneville recognizes that while the day-ahead market public process has been extensive, it is not intended to replace formal government-to-government consultation when required or requested and Bonneville looks forward to engaging in formal government-to-government consultation with the requesting federally recognized tribal governments in our service territory.

ISSUE 50: Whether Bonneville should delay its day-ahead market policy decision until government-to-government consultation is completed

Draft Policy Position

Bonneville does not address government-to-government consultation in the Draft Policy.

Public Comments

The Yakama Nation, CTUIR and Snoqualmie Tribe commenters request Bonneville not move forward with market participation until it has engaged in direct government-to-government consultation.[804] The Yakama Nation request for Bonneville to "decline to join the Market until it has engaged in full and meaningful consultation with the Yakama Nation" and extend the formal comment window until May 7, 2025."[805] The CTUIR request for Bonneville to "decline to join the Market" and "extend the formal comment window until direct government-to-government consultation with the CTUIR has been conducted."[806] The Snoqualmie Tribe further calls upon Bonneville *to "NOT* join a new day-ahead market until tribes are fully informed and consulted on any potential impacts to tribal rights."[807]

The Makah Tribe request Bonneville not join a new day-ahead market ". . . until Tribal Nations have been fully informed and engaged in consultation to evaluate potential impacts to our rights and communities."[808] The Central Council of the Tlingit & Haida urges Bonneville to delay its decision and "not to join a new day-ahead market until the federal trust responsibility is upheld through robust and meaningful consultation with tribal governments—consultation that leads to free, prior, and informed consent through a true government-to-government process."[809]

CRITFC also asks Bonneville to delay its decision until if had engaged in "government-to-government consultation with CRITFC's member tribes and has thoroughly reviewed any decision for potential impacts to the tribes' treaty-reserved resources, including the Columbia River salmon and steelhead that navigate through the federal hydropower system."[810]

ATCE urge: "BPA should delay any commitment to a day-ahead market until it has conducted extensive consultations with all affected Tribes, ensuring their concerns are addressed and

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[804] Yakama-040325 at 1; CTUIR-040725 at 3; Snoqualmie-040725 at 1.
[805] Yakama-040325 at 2
[806] CTUIR-040725 at 3.
[807] Snoqualmie-040725 at 1.
[808] Makah-040725 at 1.
[809] Tlingit & Haida at 1.
[810] CRITFC-040725 at 1.

consent is obtained."[811] ATNI argue: "BPA's current drafted decision, if advanced without timely and meaningful Tribal consultation, could result in wide-ranging impacts on Tribal rights and interests that have been inadequately assessed."[812]

Evaluation

Bonneville received multiple comments related to the timing of its day-ahead market policy decision. Commenters requested for Bonneville not to join or participate in a day-ahead market until it has engaged in government-to-government consultation. Yakama Nation and CTUIR request for Bonneville to extend its formal comment window. Yakama specifically asks for it to be extended until May 7, 2025. As described in Issue #13, Bonneville has maintained its current timeline for adoption of this policy direction. Nevertheless, as explained in Issues #48-5 herein, Bonneville that it will consult with any tribes that request government-to-government consultation and anticipates this will occur ahead of its final decision to join a day-ahead market.

Decision

Bonneville will promptly engage in government-to-government consultation as requested. Bonneville declines to extend its formal comment window on the Policy.

ISSUE 51: Whether Bonneville should review its Tribal Policy

Draft Policy Proposal

Bonneville did not address Bonneville's Tribal Policy in the Draft Policy.

Public Comments

The Yakama Nation comments, "BPA must conduct a comprehensive review of its tribal consultation practices to ensure alignment with its federal trust obligations. This review must assess whether BPA' s engagement meets the standards of early and meaningful consultation."[813] The Yakama Nation also states, "BPA must commit to maintaining open and continu[o]us dialogue with the Yakama Nation, respecting our status."[814]

Evaluation

Bonneville explained in Issue 32 herein that the Policy is a policy direction and would not affect hydroelectric operations and river management and any future participation in a day ahead market would be consistent with Bonneville's existing non-power obligations. For this reason,

[811] ATCE-040725 at 2.
[812] ATNI-040725 at 1.
[813] Yakama-040321 at 2.
[814] *Id.*

the Policy direction would not affect tribes or their resources. Bonneville's Tribal Policy does not require it to seek consultation on every decision the agency makes. Rather, the Policy states: "BPA will consult with tribal governments by deliberating, discussing, or seeking the opinion of the tribes when a proposed BPA action may affect the tribes or their resources." As part of the formal comment process, Bonneville received requests for consultation and Bonneville will consult with requesting tribes, including the Yakama Nation. Bonneville commits to maintaining an open and continuous dialogue with the Yakama Nation and other tribes regarding Bonneville's future participation in a day-ahead market.

Decision

Review of Bonneville's Tribal Policy is outside the scope of the Policy and this comment period.

9. Conclusion and Next Steps

Bonneville received a number of comments on its conclusion and next steps, which are discussed throughout the Record of Decision. In addition, Bonneville updated Section 9, Conclusion and Next Steps, in the Final Policy to reflect its stakeholder process, additional analysis pertaining to production cost modeling and hurdle rates, up-to-date governance developments, additional market design elements, and a forthcoming stakeholder engagement plan regarding seams and implementation issues.

10. Legal Assessment

ISSUE 52: Whether Bonneville's day-ahead market decision is consistent with sound business principles

Draft Policy Proposal

In Appendix A of the Draft Policy, Bonneville provided a legal assessment discussion of its statutory authorities and obligations. Bonneville analyzed its day-ahead markets policy decision using stakeholder-approved evaluation criteria, including "statutes" and "business," which is discussed in Section 4 of the Policy.

Public Comments

SCL argues "BPA's decision to join Markets+ does not comply with the agency's statutory obligation to provide 'the lowest possible rates to consumers consistent with sound business principles.'"[815] SCL alleges Bonneville "has presented no business case in its DAM evaluation and their Draft Policy and record is inadequate to support its position."[816] SCL argues that

[815] SCL-040725 at 1.
[816] *Id.* at 3.

Bonneville "eschew[ing] objective analysis and choos[ing] which factors it elevates based on whether they support its preferred outcome . . . is not consistent with sound business principles."[817]

SCL states that "until BPA is able to positively determine that joining a Day Ahead market will result in positive benefits for its customers, BPA should remain in the WEIM and defer a day-ahead market decision."[818] It asserts that "[o]n BPA's current record, joining Markets+ is arbitrary and capricious."[819] SCL lists "four key aspects illustrating the deficiencies in BPA's analysis of its own record and the facts before it": 1) "BPA fails to explain how the costs of exiting WEIM are justified by the benefits of Markets+," 2) "BPA repeatedly draws distinctions between Markets+ and EDAM that do not withstand scrutiny," 3) "BPA's own commissioned economic analysis shows that DAM itself is a better choice for BPA customers," and 4) EDAM would provide a better "footprint and connectivity."[820] SCL also raises "sound business principles" arguments in its comments on Production Cost Modeling,[821] Bonneville's business case,[822] and "differences in design."[823]

In discussing Bonneville's business case, NIPPC states it "agrees that BPA should have a sound business rationale in choosing which day-ahead market to join . . . however, it appears that EDAM provides BPA and its power customers (as a whole) with significantly more benefits than Markets+." It also argues that "neither market design appears to provide quantifiable benefits to BPA's transmission customers."[824]

RNW requests that Bonneville "explain how deciding to enter into any market with substantial uncertainties regarding its overall footprint, governance structure, and market structure represents adherence to 'sound business principles.'" It further requests that Bonneville "explain why BPA waited eight years before joining the WEIM while it is now deciding to enter into a DAM that is not yet operational."

Evaluation

SCL, NIPPC, and RNW argue that BPA's decision to join Markets+ does not comply with the agency's statutory obligation to market power at the lowest possible rates consistent with sound

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[817] *Id.* at 2.
[818] *Id.* at 12.
[819] *Id.*
[820] *Id.* at 2-13.
[821] *Id.* at 26.
[822] *Id.* at 45.
[823] *Id.* at 46.
[824] NIPPC-040725 at 2.

business principles."[825] While Bonneville consistently operates in a business-like manner, the "sound business principles" standard is primarily concerned with ratemaking.

As cited by RNW, the Flood Control Act of 1944 obligates Bonneville to "transmit and dispose of . . . power and energy in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles . . . ."[826] Similarly, the Transmission System Act states that "[s]uch *rate schedules* . . . shall be fixed and established (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles . . . ."[827] In addition, citing these two provisions, the Northwest Power Act states that "[s]uch *rates* shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System . . . over a reasonable period of years [as well as] other costs and expenses incurred by the Administrator . . . ."[828]

The Ninth Circuit has interpreted the "sound business principles" standard to apply to Bonneville's discretionary contract decisions.[829] Bonneville has broad authority to best determine how to operate consistent with the "business-oriented philosophy" reflected in Bonneville's statutes.[830] The court also recognizes Bonneville's "unusually expansive mandate to operate with a business-oriented philosophy." The court further opined that "it seems particularly wise to defer to the agency's actions in furthering its business interests, especially when the agency is responding to unprecedented changes in the market . . . ."[831]Bonneville is now similarly responding to unprecedented changes in the market and has assessed the PCM analyses and market design features to determine the best path forward for the agency.

When interpreting the statutes regarding sound business principles, the Ninth Circuit has emphasized the statutory text in which Congress chose to vest the Administrator with authority. In *California Energy Commission*, the court stated:

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[825] SCL-040725 at 1; NIPPC-040725 at 2; RNW-040725 at 6.
[826] Flood Control Act of 1944, 16 U.S.C. § 825s.
[827] Transmission System Act, 16 U.S.C. § 838g (emphasis added).
[828] Northwest Power Act, Section 7(a)(1), 16 U.S.C. § 839e(a)(1) (emphasis added).
[829] *See Ass'n of Pub. Agency Customers v. Bonneville Power Admin.,* 126 F.3d 1158, 1171 (9th Cir. 1997) ("The statutes governing BPA's operations are permeated with references to the 'sound business principles' Congress desired the Administrator to use in discharging his duties." (citing 16 U.S.C. §§ 825s, 838g, 839e(a))).
[830] *Id.* ("Thus, although Congress did not prescribe the parameters of the Administrator's authority, it granted BPA an unusually expansive mandate to operate with a business-oriented philosophy.").
[831] *Id.*

> [T]he statutes do not dictate that BPA always charge the lowest possible rates. 16 U.S.C. § 838g directs that rates be set "with a view to encouraging . . . the lowest possible rates to consumers . . . ." The words "with a view to encouraging" do not constitute a statutory command that the prices charged to consumers always be the lowest possible. Moreover, nearly every action by BPA has some arguable impact on future rates. If the strict interpretation of the "lowest possible rates" standard . . . were accepted, the discretion that Congress vested in the Administrator would be eliminated. In addition, the direction to charge the lowest possible rates is tempered by the addition of the clause "consistent with sound business principles."[832]

The Court summarized the standard in *Industrial Customers of Northwest Utilities*, stating that "[w]hen, as here, we are measuring BPA's actions against the 'sound business principles' standard embodied in BPA's governing statutes, 'we are particularly deferential to the agency's assessment of whether its actions further BPA's business interests consistent with its public mission.'"[833] Indeed, the Court recognizes that such business decisions must be made in the face of uncertainty.

In *Association of Public Agency Customers*, the Court held:

> This challenge to the soundness of Bonneville's business strategy is not persuasive. We are not to debate the wisdom of any BPA business decision unless that decision is so manifestly unreasonable as to rise to the level of being arbitrary and capricious. The decision to execute the Long-Term Extension Agreements was not.
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> . . .
>
> In short, the record does not support a charge that BPA acted arbitrarily and capriciously in approving the Block Sales Contracts. The Administrator made a reasoned business decision. As with all such choices in an uncertain market, we cannot foretell whether the strategy will succeed or not. Time may prove the Administrator's plan un-sound. However, it would be improper of us to substitute our business acumen, or lack of it, for the Administrator's. Our judicial review is confined to assessing whether the Administrator's actions were arbitrary and capricious. They were not.[834]

Bonneville has considered the relevant factors and articulated a rational connection between the facts found and the agency direction after an extensive public process. It has also evaluated the considerations raised by SCL, NIPPC, and RNW throughout this record of decision.

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[832] *Cal. Energy Comm'n v. Bonneville Power Admin*., 909 F.2d 1298, 1308 (9th Cir. 1990) (citing 16 U.S.C. § 838g).
[833] 767 F.3d 912, 922 (9th Cir. 2014) (quoting *PNGC v. Bonneville Power Admin.*, 596 F.3d 1065 (9th Cir. 2010)).
[834] 126 F.3d at 1181-82.

As other entities move towards day-ahead market participation, Bonneville believes that joining a day-ahead market will allow continued access to trading partners in the day-ahead timeframe, will allow for optimization of a broader mix of resources to serve load, and that this broader array of resources will better ensure system reliability. Bonneville recognizes the uncertainty inherent in forecasting benefits of different alternatives, and therefore considered the decision holistically. As SCL acknowledges, this decision "could have generational impacts on the Western Interconnection."[835] Over the course of that timeline, distinctions in market design parameters and governance processes to resolve future issues are very important.

Bonneville did not ignore the relevant economic analysis, including regarding the option of staying in the WEIM.[836] Bonneville concluded that its policy determination towards Markets+ is the best direction for the agency based on the PCM analyses and other factors.[837] Bonneville considered the differences in market design and explained the connection between those distinctions and the policy decision towards participation in Markets+.[838] Bonneville further discussed preliminary implementation considerations such as operational and commercial seams and reliability issues.[839] Bonneville discussed significant differences in the markets' relative governance structures.[840] There are very real differences between the two markets and the value they place on products and services. SCL may disagree with the significance that Bonneville has placed on these differences in its business judgment, but that does not mean Bonneville's decision is statutorily impermissible.

Finally, Bonneville's decision is supported by many other utilities.[841] Bonneville customers will bear the risk of Bonneville's decision through paying cost-based rates, and they have provided valuable insight and information to the agency throughout this process. Many customers have also reviewed the data and analyses, applying their business mindset, and have reached the same conclusions as Bonneville. In a letter from Puget Sound Energy, Tacoma Power, Douglas County PUD, Chelan County PUD, and Grant County PUD to Washington Governor Bob Ferguson, the utilities concluded:

> Most electric utilities serving Washington customers participated in the development of Markets+ and support BPA's process and market decision. Only

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[835] SCL-040725 at 13.
[836] *E.g.*, Policy at §§ 5.1.1 (PCM), 5.1.1.6 (Business Line Economic Impacts), 5.1.2 (Participation and Implementation Cost Estimates).
[837] *Id.* § 5.1.1.
[838] *Id.* §§ 5.2.2 through 5.2.5.
[839] *Id.* § 6.4.
[840] *Id.* § 5.2.1.
[841] AWEC-040725; CBEC-033125; Big Bend-040725; CRPUD-040725; Hood River-040425; IFP-040725; Joint Authors-040725; Lincoln-040425; Modern-040425; NRU-040725; Pacific-040725; Powerex-040725; PPC-040725; Snohomish-040725; Tacoma-040225; Umatilla-040425; Wasco-033125; WPUDA-040725.

> one Washington-based electric utility has taken a different position in opposition to Markets+. Additionally, most public power entities in the Northwest support BPA's decision to join Markets+. All electric utilities in Washington are operating in good faith to make the best decisions for their customers, but it is important to recognize the meaningful benefits that many Washington utilities recognize Markets+ will bring to the region.[842]

SCL, NIPPC and RNW may disagree with Bonneville's policy direction, but it is reasonable.

Decision

Bonneville's day-ahead market decision is consistent with sound business principles. The agency considered the relevant factors, including PCM results, the market governance framework, and design differences valuing various products and services. This Policy articulates a rational connection between the facts found and the direction forward, and it is supported by many of Bonneville's utility customers.

ISSUE 53: Whether BPA's Day-Ahead Market Draft Policy approach is sufficient to satisfy regional preference regarding surplus sales

Draft Policy Proposal

In section 2(c) of the Legal Assessment appendix to the Draft Policy, Bonneville explained that it will continue to meet its preference and regional preference obligations when making surplus sales while participating in a day-ahead market. It provides notice to its preference customers regarding the availability of short-term surplus power using a combination of: 1) annual letters notifying regional customers of surplus availability and how they may exercise their rights; 2) product specific letters/emails when Bonneville is preparing to sell a new type of product to a non-preference customer; and 3) a standing daily notification on Bonneville's website regarding the availability of surplus power and instructing regional customers on how to obtain it if they are interested. This format has been an efficient and effective way for Bonneville to participate in the short-term market while also notifying regional customers that Bonneville may have surplus power available for sale on a rolling basis.

Public Comments

NRU argued that BPA's analysis of how preference would apply to surplus sales is incomplete given the prioritization required by the Regional Preference Act. NRU remains concerned that

[842] Letter from Puget Sound Energy *et al.* to Governor Bob Ferguson, *Re: Bonneville Power Administration (BPA)'s Day-Ahead Market Draft Policy* at 4 (Apr. 15, 2025), *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/2025/20250417-letter-from-washington-utilities-to-governor-ferguson.pdf.

Bonneville's conclusion that relying on its daily standing notice prior to the market run is insufficient and contrary to the language and intent of the Regional Preference Act.

Evaluation

Bonneville's approach to how and when it communicates surplus is available for sale for use both within and outside the region is based on the following order of preference: 1) Pacific Northwest public utilities, 2) Pacific Northwest IOUs, and 3) Southwest public utilities. This order is consistent with the 1964 Pacific Northwest Consumer Power Preference Act, 16 U.S.C. § 837 *et seq.*

Since the deregulation of the electric utility industry and development of the wholesale spot market (Western Systems Power Pool) in the mid-1990s, notification to regional customers has evolved to adapt to the changes in wholesale electric markets that impact Bonneville and its customers. It is notable that since the 1960s, automation and technological developments have dramatically increased the speed in transacting the selling and buying of power. Bonneville has been transparent with its customers in changing when and how notice is given—daily and on the world wide web—which comports with the 30 days "written notice" as expressed in statute. This adjustment has benefitted Bonneville and its power customers by affording greater efficiency in transacting short-term purchases and sales. When there is a proposed long-term sale of surplus out of region by Bonneville, e.g., for a period greater than five years, a 30-day notice is provided to give regional customers the opportunity to accept the same terms, conditions, and price of the proposed sale. By following this order of regional preference, if additional power is available, Bonneville may also make surplus sales to non-preference customers. Bonneville notes that NRU raised similar concerns during the development of the EIM Policy but has not taken issue with Bonneville's approach to providing notice regarding the availability of surplus during EIM implementation.[843]

Bonneville explained in the EIM Record of Decision:

> On the specific mechanics of the notice, Bonneville intends to generally continue the regional notice format the agency has used for over 20 years. Since the advent of modern markets, Bonneville has provided notice to its preference customers regarding the availability of short-term surplus power using a combination of: (1) annual letters providing notice of surplus availability and how regional customers can exercise their rights; (2) product-specific letters/emails when Bonneville is preparing to sell a new type of product to a non-preference customer; and (3) a standing daily notification on Bonneville's website regarding the availability of surplus and instructing regional customers on how to obtain it if they are interested. Bonneville is unaware of any instance during the past 20 years where regional

[843] EIM Policy ROD at 60-62.

> preference customers took issue with the format of Bonneville's notice requirements. The regional and daily notice format has been an efficient and effective way for Bonneville to participate in the short-term market while also notifying regional customers that Bonneville may have surplus power available for sale on a daily basis.[844]

Bonneville published the EIM ROD in September 2019, and, again, has not received any customer feedback regarding concerns with purchasing surplus power from Bonneville in accordance with the statutory order of regional preference.

Bonneville satisfies preference first by making long-term firm power sales to eligible customers to meet their net requirements in accordance with section 5(b) of the Northwest Power Act, 16 U.S.C. § 839c(b). If Bonneville is unable to secure power to meet all requests for long-term firm power purchases, it will apply preference in an allocation scenario.[845]

Only after fulfilling its long-term firm power supply obligation will Bonneville market surplus power. Bonneville markets surplus power in the statutory order prescribed by the Regional Preference Act.[846] Bonneville's regional preference obligation originates in connection with the construction of high voltage transmission enabling the interconnection of the Pacific Northwest with California and the desert Southwest. Congress enacted legislation that preserved the Pacific Northwest's priority access to low-cost power from the FCRPS by placing limitations on the Administrator's disposition of surplus power.

Section 2 of the Regional Preference Act established boundaries of the Administrator's Pacific Northwest marketing area—Bonneville's primary service territory. The Preference Act established a regional preference for Pacific Northwest customers to surplus energy and surplus peaking capacity.[847] It defines "surplus energy" as "electric energy generated at Federal hydroelectric plants in the Pacific Northwest which would otherwise be wasted because of the lack of a market therefor in the Pacific Northwest at any established rate."[848] The Preference Act defines "surplus peaking capacity" as "electric peaking capacity at Federal hydroelectric plants in the Pacific Northwest for which there is no immediate demand in the Pacific Northwest at any established rate."[849] It requires contracts for the sale of power outside of the Pacific Northwest to include a sixty-day notice to withhold surplus energy, or a sixty-month notice to withhold surplus peaking capacity, either of which will trigger if the Administrator determines that they

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[844] *Id.* at 62.
[845] 16 U.S.C. § 839c(b)(6).
[846] 16 U.S.C. § 837a-c.
[847] 16 U.S.C. § 837a.
[848] 16 U.S.C. § 837c.
[849] 16 U.S.C. § 837d.

reasonably foresee that such deliveries under the contract would impair their ability to meet the energy requirements of Pacific Northwest customers.[850] The statute operates as a "caveat emptor" or buyer beware clause, as the purchaser assumes the risk and cost of replacing any power the Administrator withholds. Thus, the Preference Act discourages long-term surplus power purchases from outside of the Pacific Northwest.

Bonneville has not mischaracterized its regional preference obligation in the Day-Ahead Market Draft Policy. Bonneville will apply regional preference to surplus power in accordance with its standing daily notice. Bonneville's standing notice currently provides:

> Consistent with the Bonneville Project Act (Public Law 75-329), the Pacific Northwest Electric Power Planning and Conservation Act (Public Law 96-501), and the Act of August 31, 1964, (Public Law 88-552), Pacific Northwest (PNW) customers may request to purchase available amounts of surplus firm energy and capacity prior to the sale of such power to out-of-region customers. In addition, consistent with the laws referenced above, PNW Public utilities may request to purchase available amounts of power prior to the sale of such power to PNW Investor-Owned utilities (IOU) and PNW Direct Service Industries (DSI). Please contact your BPA representative when requesting to purchase for information on pricing and power availability.
>
> If power is available, and terms and conditions are mutually agreed upon, BPA will meet customer requests in the following order: (1) PNW Public utilities, (2) PNW IOUs and PNW DSIs, and (3) Southwest Public utilities. Thereafter, if additional power is available, BPA may also meet requests for power from non-preference customers.
>
> When requesting preference power, please contact the BPA Trading desk at BPAMarketing@bpa.gov prior to the preschedule day, and a BPA Trader will respond to you about power availability and pricing. At its discretion, Bonneville may also offer any remaining surplus FCRPS energy (capability) into the Energy Imbalance Market (EIM).[851]

In *Aluminum Co. of Am. v. Cent. Lincoln People's Util. Dist.*, the U.S. Supreme Court explained that the preference system "determines the priority of different customers when the

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[850] 16 U.S.C. § 837a, 837c.
[851] Bonneville Power Admin., Power Products Catalog (2025) (includes the Daily Notice, Annual Notice, and Long-Term Power Sales contract product offerings), *available at* https://www.bpa.gov/energy-and-services/power/products-catalog.

Administrator receives 'conflicting or competing' applications for power . . . ."[852] The Court explained that "as long as . . . power is uncommitted, the preference provisions apply. Once committed by contract, the interruptibility of the power is determined by the terms of the contract."[853] Bonneville's standing daily notice invites request for purchases of surplus power from any requesting customer. If power is available, and terms and conditions are mutually agreed upon, BPA will meet customer requests in the following order: (1) PNW Public utilities, (2) PNW IOUs and PNW DSIs, (3) Southwest Public utilities, and customers outside the region thereafter.

Bonneville's participation in a day-ahead market will not impact its surplus sales approach. Bonneville will continue to market surplus power when available prior to the day-ahead market generation and load bid submission window, and thereafter prior to the real-time market bid submission window. The day-ahead market resource schedule output does not ultimately determine real-time dispatch, the real-time market bid submission window allows for Bonneville to make additional sales if surplus power remains available. Bonneville will continue to meet its regional preference obligations when marketing uncommitted surplus power.

Decision

Bonneville has updated its legal assessment to include more information regarding its continued approach to surplus power marketing consistent with the Regional Preference Act.

ISSUE 54: Whether Bonneville will continue to sell power at cost

Draft Policy Proposal

In section 7 of the Appendix A Legal Assessment, Bonneville explained that if it participates in Markets+, it will continue to establish its power and transmission rates in Northwest Power Act section 7(i) rate proceedings, and it will set the terms and conditions for transmission service in tariff proceedings.[854] Under Section 7(a)(1) of the Northwest Power Act, the Administrator establishes "rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal power. Such rates shall be established . . . to recover . . . the cost associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment . . . over a reasonable period of years and the other costs and expenses incurred by the Administrator . . . ."[855]

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[852] 467 U.S. 380, 381 (1980).
[853] *Id* at 394 (citing 16 U.S.C. § 832d(a)).
[854] 16 U.S.C. § 839e(i).
[855] 16 U.S.C. § 839e(a)(1).

Public Comments

NRU requested additional discussion and legal analysis regarding preference and cost-based service and how Bonneville intends to allocate the cost and benefits of day ahead market in a manner consistent to provide "preference service 'at cost.'"[856]

Evaluation

Bonneville will continue to sell power at cost under applicable rates because Bonneville must meet statutory provisions obligating the agency to recover its costs, including Northwest Power Act section 7(a)(1), Transmission System Act sections 9 and 10, and section 5 of the Flood Control Act of 1944.[857] Unless Congress alters Bonneville's governing statutes, the rates for power sold under its next long-term power sales contracts and its transmission contracts will continue to be set at cost. In the day-ahead market context, Bonneville's power rates would continue to recover the cost of Bonneville's resources related to federal dams, conservation, and non-federal resources purchases, including market purchases, that are used to meet the Administrator's firm power supply obligations. Bonneville's transmission rates will also continue to be set at cost. Therefore, any future cost-based rates would reflect both the costs and benefits of the day-ahead market, assuming Bonneville's future actions towards implementing this policy direction ultimately results in a participation decision.

Decision

Bonneville will continue to market power and transmission at cost-based rates as described in section 7 of the Appendix A Legal Assessment

ISSUE 55: Whether Bonneville has considered the region and met its public purposes under the Northwest Power Act

Draft Policy Proposal

Bonneville did not address this issue in the Day-Ahead Market Draft Policy.

Public Comments

RNW states the Northwest Power Act "mandated that BPA establish programs to conserve electricity, develop renewable energy, protect fish and wildlife, and encourage public

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856 NRU-040725 at 3 (citing PPC comments RE: BPA's September 11 Day-Ahead Market Workshop, *available at* https://www.bpa.gov/-/media/Aep/projects/day-ahead-market/ppc-day-ahead-202310.pdf).
857 16 U.S.C. § 839e(a)(1); 16 U.S.C. § 838g, 838h; 16 U.S.C. § 825s.

participation in the formulation of regional power policies."[858] RNW claims Bonneville has not articulated how its proposed action meets BPA's obligations to the region.[859]

The BlueGreen Alliance also argues that Bonneville has a "statutory obligation to serve the interests of the entire Pacific Northwest region, per the Northwest Power Act."[860]

Evaluation

Bonneville has conducted its market process in a transparent and broad public process. It has included 11 public workshops to discuss concerns and issues raised by all public stakeholders and has received hundreds of comments and public input on the several phases of Bonneville's consideration of market development. This public process is consistent with section 4(g) of the Northwest Power Act and has ensured Bonneville has informed the public and invited public review and comment. Indeed, Bonneville's consideration of power markets that are developing in and around the wholesale power industry in the Pacific Northwest is critical as they are likely to impact Bonneville regardless of whether the agency joins.

As described by RNW, the Northwest Power Act outlines its public purposes. However, such purposes are connected to Bonneville's statutory based power sales contracts with its firm power customers in the Pacific Northwest or "region." The sale of firm power is intended for Bonneville's power customers in the region: specifically public body, cooperative and IOUs, as well as federal agencies and Direct Service Industries or DSIs. Presently, Bonneville's sales of firm power are with its public body and cooperative utility customers, federal agency customers, and the last remaining DSI customer. IOUs have not requested to purchase firm power from Bonneville for decades.

Decision

Bonneville achieves the Act's public purposes primarily through its power sales contracts and applicable rates. Public purpose costs are recovered in Bonneville's power rates that apply to the sale of power. For example, Bonneville acquires resources, such as conservation and renewable resources, to meet its forecasted contractual power supply obligations. Costs of such acquisitions are recovered in Bonneville's priority firm power rate. Similarly, the cost of protecting, mitigating and enhancing fish and wildlife is recovered through Bonneville's power rates. Bonneville is cognizant of the Act's public purposes and Bonneville's authorities and obligations to achieve those purposes. Therefore, as markets develop and the wholesale power industry changes, it is incumbent on Bonneville to remain nimble so that it can continue meeting its firm

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[858] RNW-040725 at 7.
[859] *Id.*
[860] Blue Green Alliance-040725 at 1.

power sales obligations and statutory purposes. Bonneville has been open and transparent in its review and decision-making process regarding day ahead markets and understands that not every stakeholder will necessarily agree with or favor which form or type of market Bonneville may ultimately decide to join, if any.

ISSUE 56: Whether Bonneville acted in accordance with the Pacific Northwest Electric Power and Conservation Planning Council's Power Plan

Draft Policy Proposal

Bonneville did not address this issue in the Draft Policy.

Public Comments

NWEC, ICL, and Earthjustice joined in comments that claim BPA's decision violates the Northwest Power Act. The group contends that Bonneville has not adequately considered the financial cost to ratepayers and the Pacific Northwest from its proposed decision to join Markets+. They contend that BPA should not join a day-ahead market without further guidance from the NW Power Council. The Northwest Power Act provides that a decision to join an electricity market must be cost-effective, consistent with the Council's Power Plan, and follow the statutory resource priority scheme. Their comment concedes that BPA has authority to join a day-ahead market pursuant to its power to contract and has authority to investigate and join an interregional regional exchange of electric power. The comment then states the Plan contemplates BPA joining EDAM as an investment in resource adequacy but then they concede the Plan does not recommend participating in any particular market.[861]

The comment also claims BPA's decision is unreasonable because it would increase regional power costs, in conflict with the requirements of the Power Act and the 2021 NW Power Plan. The Plan requires BPA to pursue a day-ahead market that would create a "substantial downward pressure" on "regional wholesale electricity prices," from "expanded renewable generation additions throughout the West."[862]

Evaluation

The statutory requirements that NWEC, ICL and Earthjustice cite do not apply in this instance because those requirements attach when Bonneville proposes or completes a resource

[861] Earthjustice-040725 at 21-25.
[862] *Id.* at 22.

acquisition, whereas this document reflects a policy direction.[863] The joint commenters note that Bonneville must prioritize the acquisition of resources that are cost-effective and aligned with the statutory resource priority scheme,[864] in some instances including a determination by Bonneville that such resource acquisitions are consistent with the Northwest Power and Conservation Council's power plan.[865] The scope of those requirements can vary depending under which statutory authority Bonneville is acquiring those resources.[866] However, as described more fully in Issue 57, Bonneville is not proposing or making any specific resource acquisition decisions here; in the absence of that triggering event, the statutory requirements that NWEC, ICL and Earthjustice identified in their joint comments are not applicable to this policy direction.

Notwithstanding the fact that Bonneville is not required to make a determination regarding consistency of this policy direction with the Council's power plan here, Bonneville disagrees with the joint commenters' position that its participation in Markets+ would conflict with the Council's power plan. The Council's 2021 Northwest Power Plan is generic in its discussion of evolving markets, recommending that "Bonneville and the regional utilities, along with their associations and planning organizations, work together and with others in the Western electric grid to explore the potential costs and benefits of new market tools, such as capacity and reserves products, that contribute to system accessibility and efficiency."[867] The Council further raises several relevant considerations:

> "Since Northwest utilities have a limited say in the governance and planning in other regions in the West and due to recent historical events, there has been reluctance on a planning basis to rely more heavily on other region's generation as a hedge against uncertainty, despite the cost advantages."[868]

Governance concerns have continued to influence Bonneville's day-ahead market policy direction. In addition:

> The Pacific Northwest currently has no such market operator, and leveraging off regional collaborations such as the Northwest Power Pool Resource Adequacy effort to achieve a similar mitigation strategy may be advantageous.[869]

The Northwest Power Pool Resource Adequacy effort referenced above evolved into the WRAP, of which SPP serves as program operator. The 2021 Northwest Power Plan encourages

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[863] Draft Policy at 68 ("[Bonneville's] participation in Markets+ is the best long term strategic direction for Bonneville, its customers, and the Northwest.").
[864] 16 U.S.C. § 839 *et seq.*
[865] *See, e.g.,* 16 U.S.C. § 839d.
[866] *See, e.g.,* 16 U.S.C. §§ 839d(b)(1)-(2), § 839d(d), § 839d(l).
[867] Northwest Power and Conservation Council, 2021 Northwest Power Plan at 48 (Mar. 10, 2022), *available at* https://www.nwcouncil.org/f/17680/2021powerplan_2022-3.pdf.
[868] *Id.* at 106.
[869] *Id.*

Bonneville and other regional stakeholders to explore new market tools, but it does not prescribe which day-ahead market Bonneville should join, nor on which characteristics alternative market options must be evaluated.

Finally, these comments attempt to conflate Bonneville's obligation to supply electric power under its statutory firm power sales contracts beyond such agreements to extend that obligation to entities and persons that are not customers. The term "customer" is defined in section 3(7) of the Northwest Power Act and means "anyone who contracts for the purchase of power from the Administrator pursuant to this chapter." The purpose of supplying an adequate, efficient, economical, and reliable power supply extends to those statutory customers that have executed firm power sales contracts offered by the Administrator. At the time the Act was passed, Congress directed Bonneville to develop and offer new long-term power sales contracts to its public bodies, cooperatives, and investor-owned utilities, directly served industries and federal agencies within the Pacific Northwest. As this purpose applies to Bonneville, it is directed at planning for Bonneville's power supply needs to meet the Administrator's power sales contract obligations to avoid insufficient power supplies that would lead to any curtailments or restrictions of electric power impacting regional firm power customers. The purpose does not extend to entities that are not customers as defined in the Act.

Decision

To the extent that Bonneville faces future resource acquisition decisions under this policy direction or another decision process, Bonneville will ensure that it complies with the appropriate statutory resource acquisition requirements.

ISSUE 57: Whether Bonneville has complied with Section 6(c) of the Northwest Power Act

Draft Policy Proposal

Bonneville did not address the applicability of section 6(c) of the Northwest Power Act to the Day-Ahead Market Draft Policy.

Public Comments

In their comments requesting government-to-government consultation, the Yakama Nation and CTUIR attached to their comment a list of issues that they would like to discuss with Bonneville through consultation.[870] In this list of issues, the Yakama Nation and CTUIR comment that Bonneville must follow the procedural requirements in Section 6(c) of the Northwest Power Act

[870] Yakama-040325 at 2; CTUIR-040725 at 2.

for acquiring major resources with a planned capability greater than fifty average megawatts and for a period of more than five years.[871] They state that Bonneville "has not conducted the resource acquisition process required in Section 6(c) of the Act."[872]

Evaluation

Section 6(c) does not apply in this instance: Bonneville is not proposing to acquire a major resource. Bonneville's policy direction toward "its participation in Markets+ is the best long term strategic direction for Bonneville, its customers, and the Northwest"[873] does not represent a "proposal . . . to acquire a major resource."[874]

As Bonneville explains in its 6(c) Policy, "to 'acquire' means to incur, and an 'acquisition' is, a contractual obligation to make payment for . . . specified rights to the output or capability of a generating resource . . . ."[875] In contrast Markets+ is a day-ahead market offering that would centralize day-ahead and real-time unit commitment and dispatch through a market clearinghouse. Bonneville's participation in such a market is not an acquisition of a resource; rather, the market offers participants the ability to buy and sell power—not resources—on a short-term basis. There is no acquisition because Bonneville makes no contractual commitment for specified rights to generating resources here.

Furthermore, setting aside the fact that this is a policy direction related to day-ahead market participation and not a decision related to specific market purchases, the individual purchases that Bonneville would expect to make in the course of its participation in Markets+ would be short-term acquisitions and therefore, by definition, be precluded from meeting the "major resource" definition under the Act—i.e. having a planned capability of greater than 50 MW *and* being acquired for a period of more than five years.[876]

Decision

The resource acquisition process required by section 6(c) of the Northwest Power Act does not apply to this Day-Ahead Market Policy.

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[871] 16 U.S.C. § 839a(12) (defining "major resource"); 16 U.S.C. § 839d(c) (procedures for acquiring major resources).
[872] CTUIR-040725 at 10; Yakama-040325 at 12.
[873] Draft Policy at 68.
[874] Northwest Power Act § 6(c)(1), 16 U.S.C. § 839d(c)(1).
[875] Policy for Section 6(c) of the Pacific Northwest Electric Power Planning and Conservation Act, 58 Fed. Reg. 35,922, 35,925 (July 2, 1993).
[876] Northwest Power Act § 3(12), 16 U.S.C. § 839a(12).

ISSUE 58: Whether Bonneville complied with section 106 of the National Historic Preservation Act by assessing historic properties

Draft Policy Proposal

Bonneville did not address its compliance with section 106 of the National Historic Protection Act (NHPA) in the Draft Policy.

Public Comments

RNW questions whether Bonneville has complied with section 106 of the NHPA and asks for evidence of compliance, including evidence of consultation with tribes.[877]

Evaluation

Bonneville must comply with section 106 of the NHPA for all undertakings as defined in the regulations implementing the NHPA at 36 C.F.R. § 800.16(y). As a threshold matter, the decision on policy direction to join Markets+ is not an undertaking as defined at 36 C.F.R. § 800.16(y). BPA's decision to adopt this policy is a stage in the decision-making process but does not reflect a final Bonneville decision to become a market participant. Such a decision would follow rate and tariff cases and execution of implementation and participation agreements.

Decision

Bonneville has not initiated an undertaking and therefore has not initiated the section 106 process. To the extent that future decisions under this policy direction or another decision process constitute an undertaking, Bonneville will ensure that it complies with the requirements of the NHPA and its implementing regulations.

ISSUE 59: Whether the uncertainty in relations between the United States and Canada impacts Bonneville's position on joining a day-ahead market

Draft Policy Position

Bonneville did not address the relationship between the United States and Canada or the Columbia River Treaty negotiations in its Draft Policy.

Public Comments

[877] RNW-040725 at 23.

Greg Dotson, an individual commenter, asserts that, since President Trump has announced tariffs on Canada, the relationship between the U.S. and Canada has deteriorated, causing uncertainty in trade of electricity between the countries.[878] Mr. Dotson also cited the Trump Administration's "pause" on Columbia River Treaty (Treaty) negotiations, which could lead to "severe" consequences if terminated.[879]

Mr. Dotson suggests that Bonneville should defer finalization of its policy until impact of the U.S. relationship with Canada can be understood and assessed.[880]

Evaluation

Bonneville does not identify the trade relationship between the U.S. and Canada as an issue that is relevant to Bonneville's day-ahead market policy.

Mr. Dotson makes conclusive statements that the recent discussions of tariffs may cause uncertainty in the electricity markets in the U.S. However, he does not provide any specific evidence of what such impacts might be or how those impacts relate to Bonneville's decision to join Markets+. While Mr. Dotson suggests that the Treaty may terminate, the Treaty is an evergreen agreement that will only terminate if either country gives ten years notice of intent to terminate. It is true that negotiations for an updated version of the Treaty are on pause, but the existing Treaty remains in effect and the U.S. and Canada continue to implement the current Treaty.

Decision

The points raised by Mr. Dotson regarding U.S. relations with Canada are outside the scope of the Policy. Further, the Treaty continues to be in effect and is being implemented by the U.S. and Canada. Bonneville sees no evidence that the current relations between the countries have a measurable impact on Bonneville's day-ahead market policy.

ISSUE 60: Whether Bonneville has adequately considered its experience with WPPSS

Draft Policy Proposal

Bonneville did not address Washington Public Power Supply System's (WPPSS) construction of nuclear power plants in Draft Policy.

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[878] Dotson-040725 at 1-2.
[879] *Id.* at 2.
[880] *Id.* at 3.

Public Comments

"And here we go again." Mr. Ritter comments "how did BPA get so far down this wrong road . . . ." Attached to Ritter's comment is a description entitled, "The Bonneville Power Administration's Role in the WPPSS Nuclear Power Debacle."[881]

Evaluation

Phil Ritter's comment harkens back to the decisions made by Bonneville and other regional utilities in the 1970s regarding the WPPSS construction of nuclear power plants in the Pacific Northwest. Bonneville and the region's utilities were among the parties that experienced and were impacted by what was then the nation's largest default on bonds backing the construction of the projects. Ritter's comment equates Bonneville's support for one day ahead market over another—Mr. Ritter's preferred one—as somehow being akin to Bonneville's involvement with the development, construction, and financial impact of the WPPSS plants. It is not. Section 6 of the Northwest Power Act sets forth Bonneville's authority to acquire resources on a long-term basis.[882] Participation in or joining a market is not the acquisition of a resource.

Decision

Bonneville like any other participant in a market must come prepared, i.e., it must show that it is resource adequate before it can either bid in its electric power to sell or to buy power from the market. This requirement alone sets apart the "1970s" need for utilities in the Pacific Northwest to enter into agreements with WPPSS to construct nuclear power projects to meet forecasted energy deficits.

ISSUE 61: Whether Bonneville meets Bonneville Project Act purposes of encouraging the widest possible use of electric energy and preventing monopolization by limited groups.

Draft Policy Proposal

Bonneville addressed its legal authorities and obligations in Appendix A to the Draft Policy.

Public Comments

RNW comments that "[n]owhere in the Draft DAM Policy does BPA articulate how entering into a relatively small, geographically distant, nascent market with inherently limited resource diversity furthers its statutory obligation to "encourage the widest possible diversified use of electric power."[883] RNW requests that Bonneville "explain how entering a market in which BPA

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[881] Ritter-040725 at 1-6.
[882] 16 U.S.C. § 839d(c).
[883] RNW-040725 at 5-6.

and Powerex–a Canadian entity seeking to sell surplus hydroelectric energy . . . make up approximately 60% of the current projected market share (and with voting in the stakeholder process weighted accordingly) meets BPA's obligation to "prevent monopolization thereof by limited groups."[884]

Evaluation

RNW queries Bonneville regarding the purposes of encouraging widespread use of electric power and preventing monopolization thereof found in the Bonneville Project Act of 1937 and the Flood Control Act of 1944.[885] First, Bonneville objects to the implication made in RNW's comment that Bonneville is itself acting as a monopoly. Second, while certain purposes are expressed such as encouraging widespread use and preventing the monopolization of electric energy produced by the Bonneville Project (followed by subsequent federal dams), Bonneville has met these purposes by constructing, operating, maintaining, and improving its transmission system to transmit federal power to markets, including its regional firm power customers. Congress understood in the 1930s that without authorizing the Administrator to construct, operate, and transmit federal power, only for-profit entities such as investor-owned utilities would have the means to build transmission to reach the Bonneville Dam. As a result of the authority to construct and operate the federal transmission system Bonneville was able to market power to three regional power customer classes: public body and electric cooperative utilities, investor-owned-utilities, and directly served industrial customers. Selling to these customer classes the electric energy produced by federal dams throughout the Pacific Northwest achieved widespread use and prevented the monopolization of such by limited groups.

Today, Bonneville meets these purposes by selling power under its Regional Dialogue long-term power sales contracts and through its continued construction, operation, maintenance, and improvement of its transmission system. With a direction towards participation in a day-ahead market, Bonneville will continue meeting these purposes by marketing power consistent with its preference obligations before making extra-regional sales. Bonneville will continue to make transmission sales under its tariff. Bonneville's participation in a day-ahead market, which optimizes generation and transmission dispatch to ensure least-cost resources serve load while considering operational constraints, does not implicate statutory purposes of encouraging widespread use or preventing monopolization of electric energy by limited groups. Instead, it expands Bonneville's access to what had previously been a market of the future.

Decision

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[884] *Id.*
[885] 16 U.S.C. § 832 *et seq.*; 16 U.S.C. § 825s.

Bonneville continues to meet its obligations to encourage widespread use of power and prevent monopolization through its firm power sales contracts, surplus power marketing practices, and sales of transmission under its tariff.

Appendix: Abbreviations and Acronyms

Abbreviation/Acronym	Definition
ACS	Ancillary and Control Area Services
AET	Assistance Energy Transfer
ATC	Available Transfer Capacity
ATCE	Alliance for Tribal Clean Energy
ATNI	Affiliated Tribes of Northwest Indians
AWEC	Alliance of Western Energy Consumers
AWS	Amazon Web Services
BA	Balancing Authority
BAA	Balancing Authority Area
BAU	Business as usual
Big Bend	Big Bend Electric Cooperative, Inc.
BlueGreen Alliance	BlueGreen Alliance
BOSR	Body of State Regulators
CAISO	California Independent System Operator
CBEC	Columbia Basin Electric Cooperative
CEBA	Clean Energy Buyers Association
CF	Conditional firm
Cowlitz	Cowlitz PUD No. 1
CPC	Columbia Power Cooperative
CPUC	California Public Utility Commission
CRITFC	Columbia River Inter-Tribal Fish Commission
CRPUD	Columbia River PUD
CRSO	Columbia River Systems Operations
CSRC	Columbia Snake River Campaign
CTA	Coordinated Transmission Agreement
CTUIR	Confederated Tribes of the Umatilla Indian Reservation
DAME	Day-Ahead Market Enhancements
DEB	Default energy bids
DMM	Department of Market Monitoring
DOE	U.S. Department of Energy
DSI	Direct Service Industry
E3	Energy and Environmental Economics
Earthjustice	NW Energy Coalition, Idaho Conservation League, Earthjustice
EDAM	Extended Day Ahead Market
EIS	Environmental Impact Statement
ESA	Endangered Species Act
EWEB	Eugene Water and Electric Board
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System

Abbreviation/Acronym	Definition
FERC	Federal Energy Regulatory Commission
Franklin	Franklin PUD
FSP	Fast-start pricing
GHG	Greenhouse gas
GRC	Governance Review Committee
Hood River	Hood River Electric & Internet Cooperative
ICL	Idaho Conservation League
IFM	Integrated Forward Market
IFP	Idaho Falls Power
IMM	Independent Market Monitor
IOU	Investor-Owned Utility
IPP	Independent Power Producer
IPR	Integrated Program Review
ISO	Independent System Operator
ISO-NE	Independent System Operator-New England
Joint Authors	Arizona Public Service Co., Chelan County PUD, Grant PUD, Powerex Corp., Public Service Co of Colorado, Salt River Project, Snohomish PUD, Tacoma Power, Tri-State Generation & Transmission Assoc. Inc., Tucson Electric Power Company
Joint Request	Renewable Northwest, Oregon Environmental Council, Clean Energy Buyers Assoc., Seattle City Light, Portland General Electric, Earthjustice, Northwest Energy Coalition, PacifiCorp, Northwest & Intermountain Power Producers Coalition, Green Energy Institute at Lewis & Clark Law School, Idaho Conservation League, Northwest Sportfishing Industry Assn., Oregon Citizens' Utility Board, Western Freedom, Sierra Club, Save Our Wild Salmon, Climate Solutions, Amazon Web Services, Oregon League of Conservation Voters, BlueGreen Alliance, Verde
Lincoln	Central Lincoln PUD
LMP	Locational marginal pricing
Makah	Makah Tribal Council
Mason	Mason PUD 3
MIP	Markets+ Independent Panel
MISO	Midcontinent Independent System Operator
MMU	Market Monitoring Unit
Modern	Modern Electric Water Company
MPEC	Markets+ Executive Committee
MPM	Market power mitigation
MSC	Markets+ State Committee
NEPA	National Environmental Policy Act
NEPOOL	New England Power Pool
NHPA	National Historic Protection Act

Abbreviation/Acronym	Definition
NIPPC	Northwest & Intermountain Power Producers Coalition
NITS	Network Integration Transmission Service
NOPR	Notice of Proposed Rulemaking
NRDC	Natural Resources Defense Council
NRU	Northwest Requirements Utilities
NWEC	Northwest Energy Coalition
OATT	Open Access Transmission Tariff
OCBR	Operational Controls for Balancing Reserves
OCGC	Oregon Clean Grid Collaborative
OMP	Oversupply Management Protocol
OR-WA Governors	Oregon and Washington Governors
OR-WA Senators	Oregon and Washington Senators
OR-WA State Agencies	Oregon Public Utilities Commission, Washington Utilities & Transportation Commission, Washington Department of Commerce, Oregon Department of Environmental Quality, Washington Department of Ecology
Pacific	Pacific PUD No. 2 of Pacific County
Pathways	West-Wide Governance Pathways Initiative
PCM	Production Cost Modeling
PG&E	Pacific Gas & Electric
PGE	Portland General Electric
PPC	Public Power Council
PSE	Puget Sound Energy
PTP	Point-to-point
Public Comments Sierra Club	Sierra Club
PSE	Puget Sound Energy
RA	Resource Adequacy
RIF	Regional Issues Forum
RNW	Renewable Northwest
RO	Regional Organization
RS	Resource Sufficiency
RSE	Resource Sufficiency Evaluation
RTBM	Real-Time Balancing Market
RTO	Regional Transmission Organization
SCE	Southern California Edison
SCED	Security Constrained Economic Dispatch
SCL	Seattle City Light
SCUC	Security Constrained Unit Commitment
SHOC	Seasonal Hydroelectric Offer Curve
Snohomish	Snohomish County PUD

Abbreviation/Acronym	Definition
Snoqualmie	Snoqualmie Tribe
SOS	Save Our Wild Salmon
SPP	Southwest Power Pool
State Agencies	OR and WA State Agencies
Tacoma	Tacoma Public Utilities
Tlingit & Haida	Central Council of Tlingit & Haida Indian Tribes of Alaska
TSP	Transmission Service Provider
Umatilla	Umatilla Electric Cooperative
WACEC	Washington Clean Energy Coalition
Wasco	Wasco Electric Cooperative
WECC	Western Electricy Coordinating Council
WEIM	Western Energy Imbalance Market
WEM	Western Energy Market
WEM-GB	Western Energy Market - Governing Body
WMEG	Western Markets Exploratory Group
WPAG	Western Public Agencies Group
WPPSS	Washington Public Power Supply System
WPUDA	Washington Public Utility District
WRAP	Western Resource Adequacy Program
WWGPI	West Wide Governance Pathways Initiative
Yakama Nation	Confederated Tribes and Bands of the Yakama Nation

Appendix: List of Commenters

Day-Ahead Market Policy Comment Reference	Bonneville Communications Assigned Comment Number	Affiliation	Commenter
ANDERSON-040325	DAM2025250034	Individual	Judith Anderson
ATCE-040725	DAM2025250135	Tribe	Chéri Smith, President & CEO
ATNI-032425	DAM2025250126	Tribe	Amber Schulz-Oliver, Executive Director
ATNI-040725	DAM2025250176	Tribe	Leonard Forsman, ATNI President
AWEC-040725	DAM2025250148	Customer Group	Bill Gaines, Executive Director
AWS-040725	DAM2025250153	Customer	Brittany Iles, Corporate Counsel
BELANGER-040725	DAM2025250122	Individual	Sheila Belanger
BENEDICT-031125	DAM2025250002	Individual	Derek Benedict
BIG BEND-040725	DAM2025250138	Customer	John Francisco, General Manager/CEO
BIRGE-040725	DAM2025250123	Individual	Sue Birge
BLUEGREEN ALLIANCE-040725	DAM2025250159	Public Interest Group	Maya Gillett, WA State Policy Manager
BORCHERDING-032425	DAM2025250042	Individual	Paul Borcherding
BOUR-040425	DAM2025250101	Individual	Miranda Bour
BOWLER-032125	DAM2025250184	Individual	Scott Bowler
BREWER-040725	DAM2025250143	Individual	Alicia Brewer
BROCK-032825	DAM2025250068	Individual	Barbara Brock
BUCKLEY-031125	DAM2025250001	Individual	Christopher Buckley
BUTLER-031825	DAM2025250023	Individual	Elsa Marie Butler
CAISO-040725	DAM2025250150	State Group	CAISO
CALLAGHY-032725	DAM2025250057	Individual	Kathleen Callaghy
CBEC-033125	DAM2025250071	Customer	Andy Fletcher, General Manager
CEAZAN-040425	DAM2025250108	Individual	Lisa Ceazan
CEBA-040425	DAM2025250102	Customer Group	Priya Barua, Senior Director of Market & Policy
CHIN-0328225	DAM2025250067	Individual	Andrea Chin
COLLINS-031725	DAM2025250018	Individual	Kyle Collins
CORETH-040425	DAM2025250103	Individual	Ian Coreth
CORFMAN-040425	DAM2025250100	Individual	Christopher Corfman
CORN-040125	DAM2025250074	Individual	George Corn
COWLITZ-040725	DAM2025250158	Customer	Gary Huhta, General Manager
CPC-040725	DAM2025250167	Customer	Lisa Atkin, General Manager
CRITFC-040725	DAM2025250114	Tribe	Aja K. Decoteau, Executive Director
CRPUD-040725	DAM2025250170	Customer	Michael Sykes, General Manager

Day-Ahead Market Policy Comment Reference	Bonneville Communications Assigned Comment Number	Affiliation	Commenter
CSRC		Public Interest Group	Anderson, Belanger, Ceazan, Corn, Dooley, Hanken-Follett, Jonas, Kraemer, Lewis, Lieberman, Marsh, McRae, Miller, Milliren, Moen, Moskal, Musgrove, Ouelette, Person, Rasmussen, Ruha, Rumiantseva, Shriner, Turrubiates Garcia
CTUIR-040725	DAM2025250168	Tribe	Gary Burke, Chairman, Board of Trustees
CUTTER-040725	DAM2025250120	Individual	Lisa Cutter
DOBSON-032125	DAM2025250038	Individual	Bruce Dobson
DOOLEY-040325	DAM2025250096	Individual	Sheila Dooley
DOTSON-040725	DAM2025250140	Individual	Greg Dotson, Associate Professor of Law
EARTHJUSTICE-040725	DAM2025250127 - DAM2025250132	Public Interest Group	Ben Otto & Fred Heutte (NWEC), Mitch Cutter (ICL), Jaimini Parekh & Todd True (Earthjustice)
EDWARDS-031725	DAM2025250016	Individual	David Edwards
ERBS-031825	DAM2025250030	Individual	Lori Erbs
EWEB-040725	DAM2025250144	Customer	Megan Capper, Energy Resources Manager
FARNESS-031425	DAM2025250009	Individual	Janet Farness
FAZZARI-032425	DAM2025250043	Individual	Angela Fazzari
FRANKLIN-040225	DAM2025250078	Customer	Victor Fuentes, Interim General Manager/CEO
FREEMAN-031425	DAM2025250010	Individual	Kris Freeman
GARMAN-032125	DAM2025250037	Individual	David Garman
GOELZ-040325	DAM2025250091	Individual	Chris Goelz
GOLL-031125	DAM2025250004	Individual	Emily Goll
HANKEN-FOLLETT-031725	DAM2025250012	Individual	Kalah Hanken-Follett
HARLAND-032825	DAM2025250059	Individual	Donald Harland
HARTER-031825	DAM2025250031	Individual	Mitchell Harter
HOFFMAN-040425	DAM2025250110	Individual	Michael Hoffman
HOLLENBECK-031825	DAM2025250028	Individual	Denise Hollenbeck
HOOD RIVER-040425	DAM2025250104	Customer	Libby Calnon, General Manager & CEO
HUGHES-040325	DAM2025250060	Individual	Adele Hughes
IFP-040725	DAM2025250136	Customer	Bear Prairie, General Manager
JACOBSON-031725	DAM2025250017	Individual	Robin Jacobson
JOINT AUTHORS-040725	DAM2025250133	Customer	Joint Authors

Day-Ahead Market Policy Comment Reference	Bonneville Communications Assigned Comment Number	Affiliation	Commenter
JOINT REQUEST-040125	DAM2025250149	Customer Group	Nicole Hughes, et al.
JONAS-040125	DAM2025250077	Individual	Jayme Jonas
KARGES-032825	DAM2025250064	Individual	Robert Karges
KENDALL-032525	DAM2025250048	Individual	Lydia Kendall
KLYM-031825	DAM2025250032	Individual	Melanie Klym
KRAEMER TAW-040425	DAM2025250106	Public Interest Group	Thomas Kraemer, Third Act Washington
KRAKAUER-040225	DAM2025250083	Individual	Wendy Krakauer
LEAVITT-040325	DAM2025250097	Individual	Donna Leavitt
LEWIS-031725	DAM2025250013	Individual	Sara Lewis
LIEBERMAN-040725	DAM2025250134	Individual	Lieberman
LILLGE-031725	DAM2025250015	Individual	Brenda Lillge
LINCOLN-040425	DAM2025250105	Customer	Tyrell Hillebrand, General Manager
LINK-031825	DAM2025250025	Individual	Virgene Link
LINK-040325	DAM2025250088	Individual	Virgene Link
MAKAH-040725	DAM2025250165	Tribe	Timothy Greene, Sr., Chairman
MARIS-040725	DAM2025250124	Individual	Celeste Maris
MASON-040725	DAM2025250155	Customer	Annette Creekpaum, CEO
MCDONALD-040325	DAM2025250087	Individual	Aidan McDonald
MCGIVERN-032425	DAM2025250044	Individual	Mike McGivern
MCMATH WALTON-032825	DAM2025250063	Individual	McMath Walton
MCMURTRY-031825	DAM2025250029	Individual	Paul McMurtry
MCRAE-032125	DAM2025250039	Individual	Therese McRae
MILLER-033125	DAM2025250082	Individual	Judith Miller
MILLER-040325	DAM2025250098	Individual	Catherine Miller
MILLIREN-032125	DAM2025250040	Individual	Patricia Milliren
MODERN-040425	DAM2025250107	Customer	Joe Morgan, CEO
MOEN-040325	DAM2025250085	Individual	David Moen
MOORE-031825	DAM2025250021	Individual	Daniel Moore
MOSKAL-031825	DAM2025250026	Individual	Mary Kay Moskal
MUSGROVE-040325	DAM2025250094	Individual	Donna Musgrove
NASON-032025	DAM2025250033	Individual	Chad Nason
NEWTON-040725	DAM2025250118	Individual	Maddy Newton
NIMMONS-032825	DAM2025250065	Individual	Rebecca Nimmons
NIPPC-040725	DAM2025250142	Customer Group	Henry Tilghman, Attorney
NRU-040725	DAM2025250154	Customer Group	Matthew Schroettnig, VP, Policy & Legal Affairs; Christopher Jones, Director, T&P Delivery

Day-Ahead Market Policy Comment Reference	Bonneville Communications Assigned Comment Number	Affiliation	Commenter
NWEC-040725	DAM2025250146	Customer Group	Benjamin Otto, Fred Huette, NWEC/Kelsie Gomanie, Angus Duncan, NRDC
OCGC-040725	DAM2025250162	Customer Group	Jana Gastellum, OR Environmental Council; Joshua Basofin, OR Clean Energy; Carra Sahler, Green Energy Institute, L&C Law; Benjamin Otto, NWEC; Eliza Walton, OR League of Conservation Voters; Kavya Niranjan, RNW
OR-WA GOVERNORS-040825	DAM2025250174	State Group	Bob Ferguson, WA Governor and Tina Kotek, OR Governor
OR-WA SENATORS-040725	DAM2025250179	State Group	Patty Murray, WA Senator; Maria Cantwell, WA Senator; Jeffrey Merkley, OR Senator; Ron Wyden, OR Senator
OR-WA SENATORS-050125	DAM2025250183	State Group	Patty Murray, WA Senator; Maria Cantwell, WA Senator; Jeffrey Merkley, OR Senator; Ron Wyden, OR Senator
OR-WA STATE AGENCIES-040725	DAM2025250173	State Group	Letha Tawny, OPUC; Brian Rybarik, WA UTC; Les Perkins, OPUC; Jennifer Grove, WA Dept of Commerce; Colin McConnaha, OR DEQ; Joel Creswell, WA Dept of Ecology
OUELETTE-040325	DAM2025250086	Individual	Tracy Ouelette
PAC_PGE-040725	DAM2025250152	Customer	Kalia Savage, Principal Transmission & Market Policy Analyst
PACIFIC-040725	DAM2025250139	Customer	Humaira Falkenberg, Power Resources Manager
PATHWAYS-040725	DAM2025250172	State Group	Scott Ranzal, PG&E, et al.
PERKINS-031825	DAM2025250020	Individual	Lela Perkins
PERSON-033125	DAM2025250081	Individual	Molly Person
PG&E-040725	DAM2025250161	Customer	Alan Meck, Principal Market Design Analyst
POWEREX-040725	DAM2025250147	Customer	Raj Hundal
PPC-040725	DAM2025250163	Customer Group	Lauren Tenney Denison, Director, Market Policy & Grid Strategy
PUBLIC COMMENTS GROUP 2	DAM2025250178	Individual	Various individuals
PUBLIC COMMENTS SIERRA CLUB	DAM2025250177	Public Interest Group	Various individuals

Day-Ahead Market Policy Comment Reference	Bonneville Communications Assigned Comment Number	Affiliation	Commenter
PUGET-040125	DAM2025250076	Customer	Jessica Zahnow, State & Regional Policy - Regional Markets
RASMUSSEN-031725	DAM2025250014	Individual	Donna Rasmussen
REDMAN-032125	DAM2025250041	Individual	Kristine Redman
REES-033125	DAM2025250070	Individual	Douglas Rees
REYNOLDS-032125	DAM2025250036	Individual	Bege Reynolds
RICHMAN-031125	DAM2025250007	Individual	Elise Richman
RINEHART-033125	DAM2025250072	Individual	Steve Rinehart
RITTER-040725	DAM2025250125	Individual	Phil Ritter, CPA
RNW-040725	DAM2025250156	Public Interest Group	Mike Goetz, Regulatory Affairs Director
ROBERTS-031825	DAM2025250024	Individual	Mark Roberts
RUHA-040325	DAM2025250093	Individual	Catherine Ruha
RUMIANTSEVA-040325	DAM2025250084	Individual	Elena Rumiantseva
RUTHERFORD-040725	DAM2025250115	Individual	James Rutherford
SALEM ELECTRIC-032825	DAM2025250058	Customer	Anthony Schacher, General Manager
SCE-040725	DAM2025250141	State Group	Jeff Nelson, Manager of Market Design and Analysis
SCHERNTHANNER-040725	DAM2025250117	Individual	Liesl Schernthanner
SCL-040725	DAM2025250160	Customer	Stefanie Johnson, Strategic Advisor
SHAFRANSKY-031725	DAM2025250019	Individual	Paula Shafransky
SHRINER-040725	DAM2025250151	Individual	Sylvia Shriner
SIERRA CLUB-040725	DAM2025250169	Public Interest Group	Damon Motz-Storey, Oregon Chapter Director; Lisa Young, Idaho Chapter Director; Ben Avery, Washington Chapter Director
SIMS-032425	DAM2025250045	Individual	Kimberly Sims
SNOHOMISH-040725	DAM2025250157	Customer	Adam Cornelius, Principal Utility Analyst
SNOQUALMIE-040725	DAM2025250171	Tribe	Michael Ross, Deputy Executive Director of Government Affairs and Special Projects
SOS-040725	DAM2025250164	Public Interest Group	Joseph Bogaard, Executive Director
SOUTH-032025	DAM2025250035	Individual	Nathan South
STEWART-032625	DAM2025250046	Individual	Brian Stewart
STOPPANI-040425	DAM2025250112	Individual	Pete Stoppani
TACOMA-040225	DAM2025250080	Customer	Ray Johnson, Deputy General Manager

Day-Ahead Market Policy Comment Reference	Bonneville Communications Assigned Comment Number	Affiliation	Commenter
TAYLOR-040725	DAM2025250119	Individual	Janet Taylor
TLINGIT & HAIDA-040425	DAM2025250111	Tribe	Richard Peterson, President
TROUT UNLIMITED-040425	DAM2025250113	Public Interest Group	Paul Nichol
TURRUBIATES GARCIA-040725	DAM2025250116	Individual	Mariana Turrubiates Garcia
UMATILLA-040425	DAM2025250109	Customer	Robert Echenrode, General Manager/CEO
UNGAR-031125	DAM2025250003	Individual	Arthur Ungar
WACEC-040325	DAM2025250092	Public Interest Group	Don Marsh, Lead
WAKEFIELD-031825	DAM2025250022	Individual	Marie Wakefield
WASCO-033125	DAM2025250073	Customer	Lindsay Forepaugh, General Manager
WPAG-040725	DAM2025250145	Customer Group	Ryan Neale, Attorney
WPTF-040725	DAM2025250137	Customer Group	Scott Miller, Executive Director
WPUDA-031225	DAM2025250008	State Group	Liz Anderson, Executive Director
YAKAMA-040325	DAM2025250089	Tribe	Gerald Lewis, Chairman
ZELASKO-032825	DAM2025250069	Individual	Sandy Zelasko
ZELIFF-032125	DAM2025250034	Individual	Molly Zeliff

CERTIFICATE OF SERVICE

In accordance with Fed. R. App. P. 15(c) and Fed. R. Civ. P. 4(i), I hereby certify that on this 10th day of July, 2025, I caused the foregoing PETITION FOR REVIEW UNDER THE NORTHWEST POWER PLANNING AND CONSERVATION ACT FOR REVIEW OF THE BONNEVILLE POWER ADMINISTRATION'S MAY 9, 2025, DAY-AHEAD MARKET POLICY AND DAY-AHEAD MARKET RECORD OF DECISION to be served via certified mail to the following:

JOHN HAIRSTON
Administrator and CEO
Bonneville Power Administration
905 N.E. 11th Avenue
Portland, OR 97232

MARCUS CHONG TIM
Executive Vice President, General Counsel
Bonneville Power Administration
905 N.E. 11th Avenue
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