

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

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 (NWECC), 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

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,

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

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

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 (WPUA)’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 WPUA 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

³⁹ *Id.* at 3.

⁴⁰ *Id.* (citing WMEG Follow-up Analysis).

⁴¹ WPUA-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

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.

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

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), available 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

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 NWECC study conducted by the Brattle Group and prepared for NWECC.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

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, NWECC, 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.

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-

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

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
 <p>EDAM: California, PacifiCorp, NV Energy & all Pacific Northwest BAAs</p> <p>Markets+: BAAs located in the Desert Southwest and Rockies</p>	 <p>EDAM: California, PacifiCorp, NV Energy, Idaho Power, Portland General Electric, Seattle City Light</p> <p>Markets+: Rest of US WECC and British Columbia</p> <p><i>Reflects current day-ahead market declarations & leanings</i></p>

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 Markets+ 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

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 2035¹⁴⁹ [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.

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

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 seams¹⁸¹ (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					
Weighted Average OATT Rate of Market + Friction + Congestion Risk	M2M		M2M2		M2M3	
	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
	M2M RT = \$7.50/MWh		M2M2 RT = \$7.50/MWh		M2M3 DA = \$5.25/MWh	
\$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,

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.

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

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.

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

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.

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

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

²³¹ Pathways-040725 at 6.

²³² *Id.*

²³³ AVEC-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

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

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

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

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 NWEAC 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; NWEAC-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 NWEAC-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

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.

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

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

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

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

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.

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.

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 NWECA 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, NWECA, and RNW characterize the SPP Board’s relationship with Markets+ and the MIP as one of “ultimate authority” and “final authority.”³³⁹

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; WPUA-031225.

³³⁴ OR-WA State Agencies-040725 at 9.

³³⁵ NWECA-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; NWECA-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 Agencies³⁴⁰ 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 NWECC 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

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 NWECC-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

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.

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/newstories/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

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

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

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

³⁹² AVEC-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; WPUA-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.

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 sector⁴⁰⁴

SCL contends that Bonneville misrepresents CAISO’s relationship with state policy, and that “City Light and Washington utilities 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 worked 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.

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

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

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 through 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,

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.

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.

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

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

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

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

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

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

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

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

⁵²² Joint Authors-040725 at 6, 34-38; Snohomish-040725 at 5.

⁵²³ Joint Authors-040725 at 6, 37.

⁵²⁴ NIPCC-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 regarding 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.

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

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:

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

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.

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.

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.

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

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.

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 commentors' 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.

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

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

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.

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

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/utis/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

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+.

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

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,

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

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

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

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

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

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

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 its 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

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

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

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.

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.

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

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’

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.

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

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 NWEA, 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 NWEA, 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 NWEA, 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

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 NWECC, 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

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.

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.

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

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 NWEA 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

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

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:

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.

. . .

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.

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

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 AVEC-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

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

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

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

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

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 NWECA, 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

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.

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.

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

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

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
EWB	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 Electricity 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 Borcharding
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 (NVEC), 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	Jayne 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 Schroettig, 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 Niranjana, 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
OULETTE-040325	DAM2025250086	Individual	Tracy Oulette
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 Zelif