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

Fiscal Years 2018-2019 Proposed	**)**	**BPA Docket No. BP-18**
Power and Transmission Rate	**)**	
Adjustment Proceeding	**)**	

INITIAL BRIEF OF

Public Power Council
Northwest Requirements Utilities
Pacific Northwest Generating Cooperative

as

JOINT PARTY 7

SUBJECT:
Financial Reserves Policy

May 2, 2017

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I. INTRODUCTION

Pursuant to the applicable rules of procedure,[1] Public Power Council ("PPC"), Northwest Requirements Utilities ("NRU"), and Pacific Northwest Generating Cooperative ("PNGC"), together designated as Joint Party 7 ("JP07") file this Initial Brief to address the proposal of BPA Staff that BPA adopt a comprehensive financial reserves policy. Members of JP07 previously filed direct (BP-18-E-JP05-01) and rebuttal (BP-18-E-JP05-02) testimony on this topic as members of Joint Party 5. All members of PPC, NRU, and PNGC are preference customers of BPA that purchase both wholesale power and transmission services from BPA. Taken together, JP07's member utilities comprise approximately 87 percent of BPA's Tier 1 power load and pay the vast majority of BPA's power costs.

Power customers have consistently supported a comprehensive reevaluation of BPA's financial policies. The focus here is on BPA's treatment of financial reserves, but it is just one piece of the agency's commitment to overall sound financial policies and management. To that end, the Administrator should adopt a financial reserves policy that will promote the agency's financial health, support its competitiveness efforts, and incent the power customers to sign long-term sales contracts. A financial reserves policy that is equitable between business lines, minimizes rate instability and rate shock, and presents a solid business case for customers is likely to meet these objectives.

The financial reserves policy BPA Staff advanced in their initial proposal is contrary to the agency's competitiveness efforts because it would create significant rate volatility, have substantially negative financial impact on Power Services' customers without clear benefits, and would not promote equity between business lines. Therefore, the Administrator should reject it outright. However, with one further modification, the "alternative option" financial reserves

[1] BPA Rules of Procedure Governing Rate Hearings at § 1010.13(c); BP-18-HOO-03.

proposal that BPA Staff advanced in their rebuttal testimony could make for a more judicious and broadly supported financial reserves policy.

II. ARGUMENT

A. BPA Must Not View the Adoption of a Financial Reserves Policy in Isolation; a Financial Reserves Policy Should Help, Not Hinder, BPA's Cost-Competitiveness Efforts.

BPA's power costs represent the majority of power supply costs for the members of JP07, making it essential that BPA considers how a financial reserves policy might impact its financial health and cost-competitiveness. BPA's stability is critical to not only its power customers but also the region, and BPA's stability is driven by its competitiveness. Both the Administrator and BPA's customers recognize that BPA is at a critical juncture to demonstrate its commitment to control the trajectory of its costs and rates.

The fundamental financial strength of BPA is its long-term contracts with its preference customers. However, the expiration of these preference power sales contracts in 2028 has rightly caused the agency to assess its long-term competitiveness, given the low wholesale market prices for electricity and the unsustainable trajectory of BPA's rates in recent years. The long-term solvency and health of the agency is contingent upon it remaining the power provider of choice for its preference customers. A well-designed financial reserves policy will allow BPA to build and maintain a healthy level of reserves while sustaining competitive power and transmission rates, which will benefit BPA's customers and the region. Conversely, an ill-designed financial reserves policy that creates significant rate volatility, or has negative financial impact on power customers without clear benefit, or fails to promote equity between business lines will undermine BPA's efforts towards competitiveness.

This is not the first time in its history that the agency has had to prove its commitment to competitiveness. A similar situation occurred in the 1990s when wholesale market prices were plummeting and the agency faced an increasingly competitive market.[2] At that time, "[n]ew market entrants, low gas prices, and surplus supplies of short-term capacity and energy in California and the Inland Southwest . . . led to steadily falling prices."[3] BPA's customers urged "BPA to take the actions, consistent with its statutory obligations, that [were] necessary to become more competitive," and to "think in terms of short-term and long-term consequences."[4] In the 1996 ROD, the Administrator observed that, "[i]n a competitive market, BPA's sales are no longer guaranteed, but rather must be earned through competitive prices and quality, reliable service."[5] A similar threat looms again.

The Administrator at that time was unequivocal that BPA's ability to meet its statutory obligations is directly connected to whether its rates are competitive. Among those obligations is ensuring cost recovery, meeting Treasury payment obligations, encouraging the widest possible diversified use of Federal power at the lowest cost consistent with sound business principles, protecting and enhancing fish and wildlife, and giving highest priority to cost-effective conservation when acquiring resources to meet the customers' needs. Confronted with the possibility of becoming uncompetitive, the Administrator explicitly recognized that:

> BPA's ability to accomplish each of the objectives that constitute its mission, however, is in jeopardy. . . Meeting these mandates requires BPA to conduct its affairs with a view toward market considerations. Absent the reforms needed to meet its competitive challenge, BPA increasingly will be hard put to recover its costs, contribute its part to the restoration of endangered fish stocks, make its payments to the Federal Treasury on time, and deliver competitive responsive products to its customers.[6]

Today, if BPA's rates continue to increase in an unsustainable manner, the agency's ability to

[2] *See* Administrator's Final Record of Decision, 1996 Wholesale Power and Transmission Rate Proposal ("1996 ROD"), WP-96-A-02, section 2.2, at 16-22 (June 1996).
[3] *Id.* at 16.
[4] *Id.* at 16-17.
[5] *Id.* at 20.
[6] *Id.* at 20-21 (citing Bonneville Project Act, 16 U.S.C. §§ 832 – 832l (1988); Flood Control Act of 1944, 16 U.S.C. § 825s (1988); Regional Preference Act, 16 U.S.C. §§ 837-837h (1988); Pacific Northwest Federal Transmission System Act, 16 U.S.C. §§ 838-838k (1988); Northwest Power Act, 16 U.S.C. §§ 839 (1988)).

ensure cost recovery as well as to fund fish and wildlife, energy efficiency, and other benefits BPA provides to the Pacific Northwest will be jeopardized.[7]

The agency has previously analyzed the situation where BPA would need to raise rates to recover costs in a competitive wholesale market environment.[8] BPA's analysis showed that "[h]igher rates did not offset the effect of reduced sales, resulting in a net revenue loss to BPA."[9] While the situation today differs slightly because BPA's preference customers are locked into the Regional Dialogue Power Contracts through 2028, these customers are planning for the future, and many feel compelled to examine alternatives because of BPA's unsustainable rate trajectory.

The counsel of the prior Administrator should inform BPA's actions and rate decisions in its current competitiveness crisis. A major first step is adopting a financial reserves policy that will help, not hinder, the agency to incent its power customers to sign long-term sales contracts and invest in the agency's financial vitality. JP07 urges the Administrator to consider a financial reserves policy in this context and not ignore the financial conditions of the present. The Administrator knows all too well of the significant cost increases that power customers have been asked to absorb in recent years. Indeed, the Administrator has recognized that ignoring actual financial conditions at the time when the rates are set is not a sound business practice.[10] The recent trajectory of BPA's rates has caused significant hardship to BPA's power customers, and even this proceeding, which was expected to produce a comparatively modest increase, is now likely to result in another high single-digit power rate increase.

While power customers remain invested in the agency's long-term health and viability,

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[7] *See* Administrator's Final Record of Decision, BP-16 Rate Proceeding, BP-16-A-02 ("BP-16 ROD") at 9-10 (July 2015) (This Administrator has also recognized that "BPA's ability to continue to meet its statutory obligations and public purpose objectives depends on maintaining [its] cost competitiveness and financial strength.").
[8] 1996 ROD at 19.
[9] *Id.* at 20.
[10] BP-16 ROD at 9-10.

the time has come for the agency to objectively demonstrate its commitment to the goal of being the low-cost energy provider of choice when new power sales contracts are offered in the next decade. As described below, the "alternative option" financial reserves proposal[11] that BPA Staff put forth in their rebuttal testimony is far more successful in achieving this goal than their initial proposal. JP07 genuinely appreciates that BPA Staff responded to power customers' concerns with the alternative option and believes that with one further modification, Staff's alternative option could make for a more judicious and more broadly supported financial reserves policy.

B. JP07 Could Support the Adoption of a Sound and Equitable Financial Reserves Policy.

BPA Staff asserted that the Agency needs to adopt a financial reserves policy because its 95% Treasury Payment Probability (TPP) standard does not provide guidance on other crucial aspects of BPA's financial reserves amounts; instead, the TPP only addresses "when BPA should intentionally increase liquidity to ensure a 95 percent probability of making the Treasury payment."[12] JP07 agrees that lack of formal guidance on financial reserves can lead to ad hoc decision-making and inconsistent outcomes, which may not be in the best interest of BPA's long-term financial health. In addition to identifying the need for a coherent policy, BPA Staff identify three primary reasons it is important to carry financial reserves: (1) liquidity, (2) credit rating support, and (3) rate stability.[13] JP07 agrees that these are relevant aspects of BPA's financial health. Although BPA's liquidity is adequately addressed through existing mechanisms, the goals of credit rating support and rate stability are laudable and could be addressed with a sound and equitable financial reserves policy.

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[11] *See* Harris et. al., BP-18-E-BPA-33 at Section 6.
[12] Harris et. al., BP-18-E-BPA-17 at 10.
[13] *Id.* at 13.

First, as noted in JP05's testimony, BPA addresses liquidity through incorporation of the TPP standard into the financial reserves policy.[14] BPA Staff acknowledged this in rebuttal testimony and agreed that a financial reserves policy is not required for BPA's liquidity.[15] They clarify that "an objective of the [financial reserves policy] is to support BPA's liquidity,"[16] but do not believe that "a new policy is needed to solve a liquidity problem."[17] In other words, while liquidity is an important aspect of BPA's financial health, liquidity needs will continue to be addressed through the TPP standard even without adoption of a financial reserves policy.

Second, BPA Staff devoted many pages of testimony to discussing the impact that an insufficient amount of reserves can have on BPA's credit rating, as well as the dangers of not having a comprehensive financial reserves policy.[18] BPA Staff note that under BPA's current policies, "BPA could operate on a negative cash basis before taking rate action to increase financial reserves," and that this can result in "long-term harm to the financial health of BPA, particularly with respect to BPA's credit rating."[19] JP07 agrees that a sound financial reserves policy can mitigate threats to BPA's credit rating, but BPA must recognize that factors other than the existence of a financial reserves policy or a certain level of financial reserves can also impact its credit rating, such as, "service area economic strength and customer base stability; willingness and ability to recover costs with sound financial metrics; and rate competitiveness."[20] As explained above and in the JP05 testimony, "these factors underscore the need for BPA to ultimately adopt a financial reserves policy that supports its initiative to become cost-competitive

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[14] *See* Deen et. al., BP-18-E-JP05-01 at 4-5.
[15] Harris et. al., BP-18-E-BPA-33 at 32.
[16] *Id.*
[17] *Id.*
[18] *See id.* at 13-18, 10-27.
[19] *Id.* at 16.
[20] Deen et. al., BP-18-E-JP05-01 at 9 (citing Moody's Public Power Rate Methodology, 1 March 2016, Appendix A).

and improve its cost trajectory."[21] Any financial reserves policy that BPA adopts must balance short-term and long-term needs. A policy that overreaches in the short-term could contribute to more damaging long-term problems with respect to BPA's competitiveness, and there is no amount of reserves that can, on their own, ensure that BPA will remain cost competitive.

Finally, BPA Staff assert rate stability as the third reason for BPA to adopt a financial reserves policy that requires BPA to hold a certain amount of reserves.[22] BPA Staff state that by accumulating financial reserves when financial performance is better than expected, financial reserves provide liquidity for "when financial results are worse than expected."[23] Staff conclude that, "[f]inancial reserves may therefore allow BPA to forgo a rate increase that would otherwise have been necessary."[24]

However, this would not be the case under Staff's initial proposal because "financial reserves that accumulate when financial performance is better than expected will be used to increase the Cost Recovery Adjustment Clause (CRAC) thresholds until Power reaches the proposed lower threshold."[25] Contrary to Staff's assertions, this means that BPA would not be able to use reserves to help offset a rate increase until both Power and the agency as a whole were above the upper thresholds set by the reserves policy.[26] BPA Staff concede that rate stability would be fully realized only "when the lower threshold has been phased in," and that "Power rate stability is somewhat impaired during the phase-in period."[27] JP07 agrees with BPA Staff that rate stability should be a primary objective of any financial reserves policy. In this regard, the alternative option BPA Staff put forth in their rebuttal testimony is a significant

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[21] Deen et.al., BP-18-E-JP05-01 at 9-10.
[22] Harris et. al., BP-18-E-BPA-17 at 19.
[23] *Id.*
[24] *Id.*
[25] Deen, et. al., BP-18-E-JP05-01 at 6.
[26] *Id.*
[27] Harris et. al., BP-18-E-BPA-33 at 40.

improvement, but needs to be further modified to mitigate the potential for rate shock.

In sum, JP07 agrees that a financial reserves policy that is transparent and equitable between business lines, minimizes rate instability, and presents a solid business case for customers may aid the agency's long-term financial health. As stated in the JP05 testimony, JP07 could support the adoption of a financial reserves policy that: "links the costs and benefits of supporting BPA's credit rating; establishes the minimum level of reserves to trigger replenishment and specifies the mechanism and timeframe for such replenishment; establishes a maximum level of reserves before using them for other purposes; and is equitable between Power and Transmission business lines."[28] As described in more detail below, the financial reserves policy BPA Staff advanced in their initial proposal does not meet these objectives and the Administrator should reject it.

C. BPA Staff's Initial Financial Reserves Policy is Unacceptable.

1. BPA's Initial Financial Reserves Policy Proposal Undermines BPA's Cost-Competitiveness Efforts and Will Lead to Rate Instability.

The financial reserves policy BPA Staff advanced in their initial proposal is counter to the agency's effort to be cost-competitive and to position itself as the power supplier of choice for preference customers post-2028. The credit agencies have noted that "two of BPA's biggest strengths are its cost-competitiveness and long-term contracts with customers," and that "[a]s the contracts get closer and closer to expiration, their weight in BPA's credit assessment diminishes."[29] BPA should not adopt policies that will lead to unnecessary rate increases and make customers question the agency's commitment to cost-competitiveness.

Specifically, BPA's initial proposal for a financial reserves policy includes mechanisms that undermine BPA's cost competitiveness and rate stability. First, the Incremental Rate

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[28] Deen et. al., BP-18-E-JP05-01 at 14.
[29] *Id.* at 12.

Pressure Limiter would ensure that "the non-Slice rate increases will be at least three percent until Power's lower threshold is met."[30] Establishing a policy that would guarantee a minimum of a three percent rate increase until the lower threshold is achieved undermines BPA's effort to be cost-competitive, and directly conflicts with competitiveness, one of the key strengths identified by the rating agencies.

Second, the Good Year Ratchet creates excessive and unwarranted rate instability. The Good Year Ratchet would take any amount of financial reserves above the current Power CRAC threshold and use those reserves to increase the CRAC threshold until it reaches the proposed lower threshold.[31] This conflicts with the methodology underlying the agency's net secondary revenues methodology, which "sets rates based on the *expected value* of net secondary over a wide range of hydrology and price scenarios."[32] As JP05 explained in its testimony, "[b]y definition, actual net secondary revenues could be either above or below the expected value, but should average out over time."[33] Assuming the expected value of net secondary revenues and relying on financial reserves in the circumstances where actuals are either above or below the expected value is an integral part of BPA's existing risk management practices. The proposed Good Year Ratchet would undermine this risk mitigation framework and be in direct conflict with how BPA forecasts secondary net revenues in rate cases.

Ironically, the Good Year Ratchet is even less flexible than BPA's existing mechanisms for responding to an unexpected decrease in financial reserves. Under the status quo, BPA is able to "use reserves flexibly to mitigate adverse business results by dictating restoration of

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[30] Deen et. al., BP-18-E-JP05-01 at 16.
[31] *Id.*
[32] *Id.* (Emphasis in original).
[33] *Id.*

reserves the next year via a CRAC."[34] In an even more extreme situation where BPA needs to utilize the Treasury note, repayment of the Treasury note is more flexible than BPA Staff's proposed Good Year Ratchet because "the Treasury Note provides for a one-year repayment, plus a one-year extension, whereas BPA Staff's proposal would mandate recovery in a single year."[35] Thus, the Good Year Ratchet and the Incremental Rate Pressure Limiter would jeopardize BPA's ability to provide competitive rates and rate stability.

2. BPA's Initial Proposal Does Not Align Costs with Benefits and Unduly Burdens Power Customers.

As noted above, the primary objective of BPA Staff's proposed financial reserves policy is to maintain BPA's credit rating. BPA Staff estimated the impact of a credit rating downgrade "could increase revenue requirements costs by as much as $33 million for Transmission Services and $22 million for Power Services per year."[36] However, as JP05 explained in testimony, this overstates the actual impact of a downgrade on an average annual basis, which "would be $22.5 million for Transmission Services and $16.1 million for Power Services per year from FY 2018 through FY 2027."[37] BPA Staff's initial proposal would result in the equivalent of an average rate impact to Power rates of at least $30 million per year, which well exceeds the maximum potential cost savings to Power of $22 million per year.[38]

Further, BPA Staff's initial proposal does not appropriately consider how each business line would benefit from a financial reserves policy that supports BPA's credit rating. BPA Staff have stated that "BPA's credit rating is critical to its capital programs for both its Power and Transmission business lines"[39] because BPA's credit rating is the primary factor in determining

[34] Deen et. al., BP-18-E-JP05-01 at 16-17.
[35] *Id.*
[36] *Id.* at 13 (citing Harris et. al., BP-18-E-BPA-17 at 17).
[37] *Id.*
[38] *Id.* at 14.
[39] Harris et. al., BP-18-E-BPA-17 at 13.

the interest rate BPA will receive on that debt.[40] As BPA Staff described, "[t]he higher the credit rating, the lower the interest rate," and thus the lower the interest expense in the business line's revenue requirement.[41] Yet, BPA Staff does not offer compelling analysis of how shouldering Power Services with 75 percent or roughly $300 million of responsibility for agency reserves would produce commensurate benefits for Power Services either in terms of lower interest expense or other expense reduction. By contrast, Transmission Services, which is more dependent on third-party borrowing, is allocated only 25 percent or roughly $100 million of responsibility.[42]

3. BPA Staff Failed to Justify the Upper Threshold in the Initial Proposal.

BPA Staff's initial proposal set the upper threshold on financial reserves at 120 days' cash on hand but failed to provide sufficient justification for why 120 days is the appropriate threshold. BPA Staff assert that it "is a 'safe place' because it equates to roughly 'four times the absolute minimum level of days' cash on hand required by Moody's.'"[43] Evidently, BPA Staff analyzed how often the Reserves Distribution Clause (RDC) would have triggered with the 120-day upper threshold since 2004, and "the RDC would have triggered 25 percent of the time over the last 12 years."[44] But again, Staff failed to explain why 25 percent is the appropriate frequency for the RDC to trigger. Staff also failed to address how numerous other factors, such as major contractual changes, BPA's debt-to-asset ratio, and power rate increases totaling 27 percent since FY 2009, could be impacted by an upper threshold of 120 days' cash on hand.[45]

For these reasons, the financial reserves policy BPA Staff advanced in their initial

[40] Harris et. al., BP-18-E-BPA-17 at 13.
[41] *Id.*
[42] *See* Power and Transmission Risk Study, BP-18-E-BPA-05, at Tables 11 and 12; *see also* Harris et. al., BP-18-E-BPA-33 at 141.
[43] Deen et. al., BP-18-E-JP05-01 at 15.
[44] *Id.* (citing Response to Data Request NR-BPA-26-16).
[45] *Id.*

proposal is unacceptable and should be rejected.

D. The Administrator Should Reject Proposals Advanced by JP02, Powerex and MSR.

Joint Party 2 ("JP02"), Powerex, and M-S-R Public Power Agency ("MSR") raise a variety of concerns related to BPA Staff's initial proposal and the JP05 proposal for a financial reserves policy. There are a number of commonalities among those concerns, in particular with respect to equity among business lines and the phase-in for the collection of reserves attributable to Power Services. For the reasons set forth below, these concerns are misguided and not supported by the facts. Further, MSR's proposal to "lend" reserves between business lines is in conflict with how BPA manages its reserves.

1. The Concerns of JP02, Powerex, and MSR Regarding Equity Between Business Lines Are Not Supported by the Facts.

A common theme in the JP02, Powerex, and MSR testimony is that there is inherent inequity in the relative distribution of financial reserves between the Power and Transmission business lines. Their primary argument is premised on a narrow and simplistic analysis pointing out that in recent years and on a projected basis for the BP-18 rate period, Transmission has a higher attribution of reserves than Power. They claim that this is demonstrative of an inequity between the business lines.[46]

By limiting their analysis to whether the financial reserves held by Transmission and Power are proportionate to the revenue requirement of the business line, JP02, Powerex, and MSR fail to consider other important factors relevant to equity. The first fact that these parties overlook is the change in the relative amount of financial reserves attributed to each of Power and Transmission over time.[47] Recently, it is true that more reserves have been attributed to

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[46] *See* Opatrny, BP-18-E-PX-01 at 13; Wrigley et. al., BP-18-E-JP02-01 at 7; and Arthur, BP-18-E-MS-12 at 24.
[47] Deen et. al., BP-18-E-JP05-02 at 6.

Transmission than Power. However, extending the analysis further, it becomes clear that this has not always been the case. In fact, "between 2004 and 2009, more than half of the agency's financial reserves were attributed to Power, with a peak of more than 80% of the agency's financial reserves attributed to Power in 2006 and 2007."[48] BPA Staff also reiterate that the longer-term interaction between business lines is the appropriate metric to examine, not short-term snapshots of which business line is attributed greater reserves. BPA Staff state that "a short-term reliance by one business line on financial reserves attributed to the other is not inequitable as long as there are provisions in place to ensure that such reliance is truly only short-term."[49]

Any evaluation of the equitability of financial reserves policy must also take into account the benefits of such policy in comparison to the costs of carrying the reserves. Simply looking at financial reserves in comparison to a business line's operating expenses does not achieve this and does not tell the whole story. JP02, Powerex, and MSR fail to account for the relative benefits each business line would see and therefore draw faulty conclusions with respect to equitability. One of BPA Staff's stated reasons to adopt a financial reserves policy is to support BPA's credit rating; consequently, the primary benefit to the agency is reduced interest expenses that result from a higher credit rating.[50] BPA Staff calculate that a credit rating downgrade would add approximately 50 basis points to the agency's borrowing costs on newly issued non-Federal debt.[51]

Determining who benefits from a stronger credit rating requires consideration of the capital expenditures of each business line. BPA Staff state that over the course of the next 10

[48] Deen et. al., BP-18-E-JP05-02 at 6; BPA Financial Reserves Workshop #3 at 18 (June 15, 2016).
[49] Harris et. al., BP-18-E-BPA-33 at 136.
[50] Deen et. al., BP-18-E-JP05-01 at 7.
[51] Harris et. al., BP-18-E-BPA-17 at 17.

years, BPA plans to issue approximately $3.9 billion in non-Federal debt for Power and $5.4 billion for Transmission.[52] Taking into account these planned debt issuances, a 50-basis-point interest rate increase could increase the Transmission revenue requirement by up to $33 million and the Power revenue requirement by up to $22 million.[53] Transmission customers clearly have more to gain from the proposed BPA financial reserves policy, and any sound financial reserves policy should reflect that.

JP02, Powerex, and MSR also mischaracterize the interaction between the TPP standard and the financial reserves policy. The TPP standard and financial reserves policy serve two different purposes. The TPP standard addresses revenue volatility and is BPA's primary method of assessing its need for liquidity.[54] On the other hand, BPA Staff proposed a financial reserves policy with the intent of being responsive to concerns raised by the credit rating agencies and consequently increasing the likelihood of maintaining BPA's credit rating.[55] JP02, Powerex, and MSR do not fully appreciate this distinction. For example, in an attempt to declare the proposed financial reserves policy inequitable, MSR states that it is "not equitable for one business line to be forced to carry greater reserves than necessary to meet its liquidity, while the other is permitted to carry far less than necessary for an extended period of time."[56] Likewise, Powerex incorrectly states that "Transmission is carrying the burden of internal liquidity" because financial reserves attributed to Transmission are greater than the financial reserves attributed to Power based on recent history and projections for the BP-18 rate period.[57]

JP02, Powerex, and MSR rely on these mischaracterizations of the interaction between

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[52] Harris et. al., BP-18-E-BPA-17 at 17.
[53] *Id*.
[54] *See* Harris et. al., BP-18-E-BPA-33 at 32; Deen et. al., BP-18-E-JP05-02 at 11.
[55] Harris et. al., BP-18-E-BPA-33 at 29.
[56] Arthur, BP-18-E-MS-12 at 25.
[57] Opatrny, BP-18-E-PX-01 at 16.

the TPP standard and the financial reserves policy to argue that BPA should not use the Treasury Facility when calculating whether Power Services satisfies the TPP standard.[58] As stated previously, revenue volatility is addressed by the TPP. Each business line is required to meet the TPP standard on a standalone basis and therefore neither business line is forced to take on an undue share of BPA's liquidity needs.[59] JP05 correctly points out that:

> The 95 percent TPP standard should remain in place and be separate and distinct from a financial reserves policy that primarily supports BPA's credit rating. These two policies serve very different purposes; combining the two muddles that distinction and potentially lessens the effectiveness of both policies because of misunderstandings of their applications and purposes.[60]

Additionally, eliminating the use of the Treasury Facility for determining whether Power meets or exceeds the TPP standard would materially harm Power customers. The result would be higher rates or a substantially higher probability that the CRAC would trigger.[61] This outcome would occur not out of necessity, but because BPA chose not to take into account all of the liquidity tools it had available.[62] For these reasons, it is imperative that BPA continue its current approach of using the Treasury Facility when calculating TPP.

2. Arguments to Limit a Phase-In Are Not Grounded in Sound Financial Management.

JP02 and MSR each critique the phase-in of BPA Staff's financial reserves proposal for Power. JP02 argues that a 10-year phase-in for Power is "too long and uncertain."[63] Along the same lines, MSR believes the "proposed Phase-In elements for Power avoid rate shock, but undermine the Policy Goals of maintaining equity, setting lower and upper reserves thresholds,

[58] Wrigley et. al., BP-18-E-JP02-01 at 9; Arthur, BP-18-E-MS-12 at 21; Opatrny, BP-18-E-PX-01 at 5.
[59] Deen et. al., BP-18-E-JP05-02 at 12.
[60] *Id*.
[61] *Id*. at 13.
[62] *Id*.
[63] Wrigley et. al., BP-18-E-JP02-01 at 2.

and ensuring Treasury repayment."[64] In making these assertions, JP02 and MSR ignore the larger context surrounding the impact of BPA's financial reserves policy on power rates and the need for BPA to achieve cost-competitiveness for its power customers. These considerations, however, are not lost on BPA's power customers. BPA also recognizes the importance of taking cost impacts into account and specifically refutes JP02's position by stating that it "disagree[s] with [the] JP02 interpretation of the phase-in. The phase-in is meant to strike a balance between rate shock and equity between business lines while protecting the Agency's credit rating."[65]

It is critical that BPA take into account cost and rate impacts associated with any financial reserves policy.[66] As pointed out by JP05, "[m]aintaining a particular credit rating level is a business decision based on the costs and benefits of doing so. Failing to consider the costs of implementing a policy for credit rating support would constitute unsound financial management."[67]

Although JP02 and MSR raise general complaints about the phase-in of a financial reserves policy, they do not offer specific proposals or recommendations. BPA Staff sum up the lack of support by stating that "[w]hile JP02 may want this to be done over a 'shorter' period it has not proposed how to do this and fails to explain what compelling policy or factual basis supports its undefined 'shorter' period."[68] BPA Staff's alternative option submitted in rebuttal testimony offers a predictable course of action to collect reserves for credit support, without the uncertainty surrounding the phase-in mechanisms included in the initial proposal.

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[64] Arthur, BP-18-E-MS-12 at 1.
[65] Harris et. al., BP-18-E-BPA-33 at 81.
[66] Deen et. al., BP-18-E-JP05-02 at 14.
[67] *Id*.
[68] Harris et. al., BP-18-E-BPA-33 at 81.

3. MSR's Proposal to Lend Reserves Between Business Lines Should Not be Adopted.

MSR proposed a "measure that would permit the Administrator to 'lend' reserves from one entity to the other at the highest prevailing interest rate of the lending entity."[69] MSR's characterization of each business line as an "entity" illustrates its misunderstanding of BPA's financial management. BPA is "a single entity, with one account responsible to meet all expenses from both Transmission Services and Power Services, and therefore its creditworthiness is based on BPA as one entity."[70]

Further, BPA already attributes interest credits to each business line based on the amount of reserves that are attributed to that business line.[71] This means that each business line is already receiving fair value from any reserves that are attributable to that business line in the form of lower net interest expenses.

BPA Staff provided additional rationale in their rebuttal testimony as to why MSR's proposal is inappropriate:

> [A] temporary imbalance between business line contributions to the Agency's financial reserves is acceptable so long as it is not systemic or long-term, and both business lines continue to contribute reasonable amounts. BPA's proposed FRP puts Power and Transmission's financial reserves on a path to be balanced within the next 10 years. Thus, compensation for the temporary lost opportunity from one business line to the other is not warranted, and should be cautioned against given the many interdependencies between the two business lines that are tied together physically, legally, and financially.[72]

For the reasons above, adopting MSR's proposal to "lend" between business lines at the highest prevailing interest rate runs counter to how BPA manages its reserves and does not serve a useful purpose for BPA, or either of its business lines individually.

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[69] Arthur, BP-18-E-MS-12 at 33.
[70] Deen et. al., BP-18-E-JP05-02 at 15-16.
[71] *Id*. at 16.
[72] Harris et. al., BP-18-E-BPA-33 at 98.

E. BPA Staff's Alternative Option Is an Improvement to the Financial Reserves Policy BPA Staff Advanced in the Initial Proposal.

As discussed above, the financial reserves policy BPA Staff advanced in their initial proposal was so problematic and such a poor business proposition for power customers that they testified that "risking a downgrade would be financially preferable for power customers relative to BPA staff's proposal."[73] Specifically, JP05 testified that the financial reserves policy BPA Staff advanced in their initial proposal was "fundamentally problematic" and contrary to the agency's competitiveness efforts because it would (1) create significant rate volatility; (2) have substantially negative financial impact on Power Services' customers without clear benefits; and (3) not promote equity between business lines.[74] BPA Staff's alternative option alleviates these concerns to some extent in two primary ways.

First, BPA Staff's alternative option allocates responsibility for agency's financial reserves to each business line "based on its fraction of a 10-year projection of BPA capital spending."[75] This allocation results in approximately 45 percent allocation of responsibility to Power Services and 55 percent allocation of responsibility to Transmission Services, or $180 million to Power and $220 million to Transmission for the BP-18 period.[76] By contrast, BPA Staff's Initial Proposal implicitly allocated responsibility for agency reserves by the size of each business line as measured in operating expenses, which shouldered Power Services with 75 percent or roughly $300 million of responsibility for agency reserves, and Transmission Services with 25 percent or roughly $100 million of responsibility.[77] This inequitable allocation of responsibility to Power Services came with no commensurate benefits to its customers, given

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[73] Deen et. al., BP-18-E-JP05-01 at 21.
[74] *Id*. at 17.
[75] Harris et. al., BP-18-E-BPA-33 at 145.
[76] *Id*.
[77] *See* Power and Transmission Risk Study, BP-18-E-BPA-05, at Tables 11 and 12; *see also* Harris et. al., BP-18-E-BPA-33 at 141.

that the benefit to power customers of avoiding a downgrade was $16 million per year on average, roughly half of the power customers' projected cost.[78] Because power customers were expected to bear the majority of responsibility for the agency's financial reserves, the cost of such a financial reserves policy greatly exceeded any benefits power customers would derive from maintaining BPA's current credit rating.

JP07 appreciates that in their alternative option, BPA Staff adopted the power customers' suggested method of allocating responsibility for the agency's reserves based on the percentage of total capital expenditures attributable to each business line over the next 10 years. While this allocation method is less advantageous to power customers over other potential allocation methods such as projections of third-party borrowing, it takes a long-term and balanced view of aligning costs and benefits and acknowledges that both business lines benefit from BPA managing its debt portfolio on an integrated basis.[79] Most importantly, this allocation method addresses perhaps the most problematic feature of BPA Staff's initial proposal – the inequitable treatment of Power Services relative to Transmission Services. By better aligning the costs of maintaining the agency's credit rating with the benefit to each business line of borrowing lower-cost money, the alternative proposal gets closer to actually maintaining equitable treatment between business lines.

Second, BPA Staff's alternative option wisely replaces the initial proposal's Good Year Ratchet and Incremental Rate Pressure Limiter with a proposal to include $20 million of Planned Net Revenues for Risk ("PNRR") per year in Power's revenue requirement in each rate period until forecast Power financial reserves exceed the Power lower threshold.[80] Staff's proposed Good Year Ratchet would result in excessive and unacceptable rate instability for power

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[78] Deen et. al., BP-18-E-JP05-01 at 21-22.
[79] *See id*. at 23-24.
[80] Harris et. al., BP-18-E-BPA-33 at 145.

customers.[81] In essence, in order for Power Services to reach its share of the agency's lower reserves threshold, the Good Year Ratchet would continuously usurp any amount of reserves above the current CRAC threshold and use those reserves to increase the CRAC threshold until it reached the proposed lower threshold.[82] Effectively, the Good Year Ratchet ensured that Power Services would have minimal reserves available for risk until it reached its lower threshold, and resulted in BPA being on the verge of a CRAC – and power customers being on the verge of an unpredictable rate increase – virtually all the time.[83] Further, the initial proposal's Incremental Rate Pressure Limiter meant that the non-Slice rates would increase at least three percent each rate period until Power met its lower reserves threshold.[84] Although power customers participating in the rate case vehemently testified against these aspects of BPA's initial proposal, BPA Staff continues to wonder whether some power customers "might prefer a rate impact that was less certain, and that might depend more on financial performance."[85]

Suffice it to say that members of JP07 have no appetite for excessive and unwarranted rate instability over the next 10 years and much prefer the alternative option's predictable approach of increasing reserves through a steady amount of PNRR. Power customers advocated for this approach all along because it has "the benefit of being fully transparent and known during the course of a rate period as well as decreasing the likelihood of a CRAC, thereby enhancing rate stability at the same time as taking action to support BPA's credit rating."[86] However, members of JP07 also understand BPA Staff's desire to have a reserves policy that specifies when to increase the Power CRAC threshold from its current level of $0 to the lower

[81] Deen et. al., BP-18-E-JP05-01 at 16.
[82] *Id*.
[83] *See* Harris et. al., BP-18-E-BPA-33 at 142.
[84] Deen et. al., BP-18-E-JP05-01 at 16.
[85] Harris et. al., BP-18-E-BPA-33 at 143.
[86] Deen et. al., BP-18-E-JP05-01 at 24.

threshold for Power. There is merit to the alternative option's concept of combining the PNRR with a one-time ratchet in the Power CRAC threshold. Unfortunately, the one-time ratchet could still expose power customers to excessive and unwarranted rate shock. However, with one modification discussed below, BPA Staff's alternative option could make for a tolerable financial reserves policy.

F. BPA Staff's Alternative Option Must Be Modified to Mitigate Potential Rate Shock to Power Customers.

In rebuttal testimony, BPA Staff noted that while the financial reserves policy they proposed in the initial proposal is their "preferred option," the alternative option they advanced in rebuttal testimony "is also a strong alternative that the Administrator should consider."[87] As explained above, given the circumstances surrounding the Administrator's rate decisions in this case and the serious flaws of the initial proposal, BPA Staff's alternative financial reserves policy option is the only Staff proposal the Administrator should consider adopting, although with one much-needed modification.

Pursuant to BPA Staff's alternative option, each business line's lower threshold would be based on its share of BPA's capital spending over the next 10 years, multiplied by the agency 60 days' cash on hand level.[88] This would mean that Power Services would have a lower threshold requirement of approximately $180 million for the BP-18 period. For Power Services to reach the lower threshold, $20 million of PNRR per year would be included in Power Service's revenue requirement and collected in power rates until forecast Power Services financial reserves meet or exceed Power Services' lower threshold.[89] At that point, the Power CRAC threshold would immediately increase from the current level of $0 to the Power Services' lower threshold

[87] Harris et. al., BP-18-E-BPA-33 at 140.
[88] *Id*. at 145.
[89] *Id*. at 145-46.

level ($180 million for BP-18 period).[90] From then on, the Power CRAC threshold would remain at Power Services' portion of the agency's lower threshold level for all future years.[91] In other words, when Power Services end-of-year financial reserves are forecasted to reach Power Services' lower threshold level (either through collection of PNRR or natural reserves accumulation) as established by the reserves policy, the Power CRAC threshold would immediately be ratcheted up in a single step to the level of Power Services' lower threshold, or $180 million in the case of BP-18.[92]

This proposed one-time ratchet still raises significant concerns about rate shock in the situation where poor financial results occur following the CRAC ratchet. In this circumstance, power customers would be suddenly exposed to a CRAC that would not otherwise have occurred. Consider, for example, a rate period where Power Services is forecasted to reach exactly $180 million in reserves (assuming that Power Services' lower threshold is $180 million). Under BPA Staff's alternative option, the Power CRAC would increase from its current level of $0 to $180 million at once. Due to adverse hydrological conditions, Power Services loses $100 million in financial reserves during the first year of the rate period, leaving Power Services' reserves at $80 million. Under BPA Staff's alternative option, the Power CRAC would trigger for $100 million – and cause an immediate five-percent average rate increase on top of any proposed baseline rate increase – in the second year of the rate period. Had the CRAC threshold not increased, or increased incrementally, power customers would have seen neither a CRAC nor the additional rate increase. The agency would have simply gone back to adding $20 million of annual PNRR in each rate period until the Power Services' reserves were restored to the lower threshold level.

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[90] Harris et. al., BP-18-E-BPA-33 at 145.
[91] *Id*. at 143.
[92] *Id*.

BPA Staff correctly testified that "[i]n developing any policy, there are often competing interests that inevitably lead to tradeoffs."[93] In an effort to be constructive and demonstrate their commitment to the agency's long-term financial health, the power customers told the agency they could "support BPA adopting a financial reserves policy *but only if* it is transparent, *minimizes rate instability*, is equitable between Power Services and Transmission Services, and has a strong business case with benefits that exceed costs."[94] BPA Staff seem to agree that among the competing objectives that need to be balanced in the development of a financial reserves policy are the need to minimize rate shock and the impact of this new policy.[95]

1. JP07's Proposed Two-Step Phase-in of Power CRAC Threshold.

To mitigate the potential rate shock associated with a one-step CRAC ratchet, JP07 urges the Administrator to modify BPA Staff's alterative proposal to phase in the CRAC threshold in two steps with a buffer in reserves, rather than in one step. For example, when Power reserves reach the lower threshold of $180 million, rather than the CRAC threshold increasing all the way to that amount, the threshold would increase to 50 percent of the Power Services' lower threshold as Step 1 (or $90 million, using BP-18 period numbers). Unless Power reserves fall below the lower threshold level for Power Services, the agency would stop collecting yearly PNRR of $20 million but would continue to add to reserves through natural accumulation. When Power reserves reach 150 percent of Power Services' lower threshold (or $270 million, using BP-18 numbers), then as Step 2, the Power CRAC threshold would increase to the amount of Power Services' lower reserves threshold as established by the agency reserves policy (or $180 million, using BP-18 numbers). From then on, the Power CRAC threshold for the subsequent

[93] Harris et. al., BP-18-E-BPA-33 at 78.
[94] Deen et. al., BP-18-E-JP05-01 at 1 (emphasis added).
[95] *See* Harris et. al., BP-18-E-BPA-33 at 78; 81 ("The phase-in is meant to strike a balance between rate shock and equity between business lines while protecting the Agency's credit rating."); 101 ("As described above, we have modeled our proposal and have demonstrated that the Good Year Ratchet and IRPL can be used to limit rate shock without severely reducing the likelihood that replenishment of financial reserves attributable to Power will occur.").

and all future years would be set at the Power Service's share of the agency's lower threshold level of 60 days' cash on hand.

Following this two-step phase-in of the CRAC threshold, any time Power Services' reserves fall below its lower threshold level, a Power CRAC would trigger to replenish them to the appropriate amount in the following year. Under this approach, even as the CRAC threshold is raised substantially and eventually reaches BPA Staff's recommended level, there is always a sizable buffer at the time of the increase to mitigate for bad financial results and protect the power customers from an untimely CRAC.

Consider the difference this modification would make for power customers in the previous example. In a rate period where Power Services is forecasted to reach exactly $180 million in reserves (assuming that Power Services' lower threshold is $180 million), the Power CRAC would increase from its current level of $0 to $90 million. Due to adverse hydrological conditions, suppose Power Services loses $100 million in financial reserves during the first year of the rate period, leaving Power Services' reserves at $80 million. Under JP07's modification to BPA Staff's alternative option, the Power CRAC would trigger for $10 million instead of $100 million – and increase the power rates by less than one percent instead of five percent – in the second year of the rate period. BPA would return in the following rate period to collecting $20 million in PNRR per year until Power reserves have been restored to Power Services' lower threshold level set by the reserves policy.

Notably, power customers would still bear the risk of a substantial CRAC after the phase-in is complete and the Power CRAC threshold is equivalent to the Power Services' lower threshold for financial reserves. However, until then, JP07's modification to BPA Staff's alternative proposal provides power customers with a buffer that would limit rate shock without substantially reducing the likelihood that reserves attributable to Power Services will be steadily and surely replenished. Thus, this modification meets BPA Staff's objective of having a financial reserves policy that specifies precisely when the Power CRAC threshold will increase from its current level of $0 to the appropriate lower threshold for Power Services.[96]

As part of their rebuttal testimony, BPA Staff performed an analysis that considers the probability of BPA's financial reserves falling below 30 days' cash on hand on a sustained basis under the status quo, BPA Staff's initial proposal and alternative option, and rate case parties' alternative proposals.[97] BPA Staff testified that relative to the status quo, their alternative option "performed quite well" when it reduced the likelihood of agency financial reserves falling below 30 days' cash on hand for two years from 20 percent to 12 percent.[98] Indeed, BPA Staff's alternative option performed better than their initial proposal on this metric, reducing the likelihood of agency financial reserves falling below 30 days' cash on hand for two years from 13 percent in BPA's initial proposal to 12 percent in BPA Staff's alternative option.[99]

Using BPA Staff's modeling tools, JP07 analyzed its modification to BPA Staff's alternative option and found the modification to have minimal impact.[100] Specifically, JP07's modification would increase the probability of agency reserves falling below the 30 days' threshold from 12.4 percent to 12.9 percent.[101] The modification would also reduce the expected cost to power customers by approximately $1 million annually. But more importantly, JP07's modification would substantially mitigate the possibility of rate shock in the event of a bad financial performance following the CRAC threshold increase without increasing the probability

[96] *See* Harris et. al., BP-18-E-BPA-33 at 143.
[97] *Id*. at 22, 151.
[98] *Id*. at 151.
[99] *Id*.
[100] Data Responses Admitted via BP-18-M-MS-06, BP-18-E-MS-15 at 63 (Response to Data Request PP-BPA-26-60).
[101] Notwithstanding BP-18 discovery deadlines, JP07's work papers supporting this analysis will be made available upon request.

of the agency reserves falling below what BPA Staff perceives to be a dangerous level. It would also better balance the potential rate impacts to Power customers with the potential benefits of providing the agency with credit support.

III. CONCLUSION

For the reasons presented above, JP07 respectfully requests that the Administrator reject the financial reserves proposal BPA Staff advanced in their initial proposal, and consider adopting BPA Staff's alternative option with JP07's proposed modification.

Respectfully submitted this 2nd day of May, 2017.

s/ Irene A. Scruggs	*s/ Betsy Bridge*	*s/ Christopher Hill*
Attorney for PPC	Attorney for NRU	Attorney for PNGC

Post-Hearing Exhibit List of Joint Party 7

Exhibit	Document Title	Date Filed	Status
BP-18-E-JP05-01	Direct Testimony of Joint Party 5	1/31/17	Admitted
BP-18-E-JP05-02	Rebuttal Testimony of Joint Party 5	3/14/17	Admitted
BP-18-Q-PP-03	Qualification Statement of Michael Deen	1/23/17	Admitted
BP-18-Q-NR-01	Qualification Statement of Megan Stratman	1/27/17	Admitted
BP-18-Q-PN-02	Qualification Statement of Scott Russell	1/26/17	Admitted
BP-18-Q-PN-01	Qualification Statement of Greg Mendonca	1/26/17	Admitted
BP-18-Q-PP-01	Qualification Statement of Kevin O'Meara	1/23/17	Admitted
BP-18-Q-PP-04	Qualification Statement of Chris Weber	1/23/17	Admitted
BP-18-M-MS-06	Joint Motion to Admit Evidence	4/5/17	Admitted
BP-18-E-MS-15	Data Responses Admitted via BP-18-M-MS-06	4/21/17	Admitted

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing on the Bonneville Power Administration's Office of General Counsel, the Hearing Clerk, and all litigants in this proceeding by uploading it to the BP-18 Rate Case Secure Website pursuant to BP-18-HOO-02 and BP-18-HOO-05.

DATED: May 2, 2017.

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

Fiscal Years 2018-2019 Proposed	**)**	**BPA Docket No. BP-18**
Power and Transmission Rate	**)**	
Adjustment Proceeding	**)**	

INITIAL BRIEF OF PUBLIC POWER COUNCIL

SUBJECT:
Montana Intertie Rate

May 2, 2017

TABLE OF CONTENTS

I. INTRODUCTION

Pursuant to the applicable rules of procedure,[1] the Public Power Council ("PPC") submits this Initial Brief to address issues relating to the rates the Bonneville Power Administration ("BPA") charges for transmission service over the Eastern Intertie segment. The record in this proceeding does not support a decision to reverse BPA's longstanding practice of treating the Eastern Intertie as a separate transmission segment and charging the Montana Intertie rate (IM rate) for service over that segment. BPA Administrators considered and rejected proposals to eliminate the IM rate or roll in the costs of the Eastern Intertie in the BP-12, BP-14, and BP-16 rate cases.[2] There have been no material changes since those decisions were made. Therefore, the Administrator should maintain the Eastern Intertie as a separate segment and once again reject the proposals to eliminate the Montana Intertie rate.

II. ARGUMENT

Previous BPA Administrators have noted that "[c]hanging the allocation of costs of transmission facilities previously classified as a separate segment in rates is a segmentation decision that must be supported by an appropriate rate case record,"[3] and that "the separate segmentation of BPA's Eastern Intertie capacity … should be changed only with good reason."[4] These observations are consistent with the basic procedural requirements of administrative law. While the agency may certainly change its existing policy, it needs to provide a reasoned explanation for the change and "show that there are good reasons for the new policy."[5] In explaining a change in policy, "an agency must also be cognizant that longstanding policies may

[1] BPA Rules of Procedure Governing Rate Hearings at § 1010.13(c); BP-18-HOO-03.
[2] Fredrickson et. al., BP-18-E-BPA-26 at 4.
[3] Administrator's Final Record of Decision, 2012 Wholesale Power and Transmission Rate Adjustment Proceeding, BP-12-A-02 ("BP-12 ROD") at 480 (July 2011).
[4] Administrator's Final Record of Decision, BP-14 Power and Transmission Rate Proceeding, BP-14-A-03 ("BP-14 ROD") at 176 (July 2013) (citation omitted).
[5] *Encino Motorcars, LLC v. Navarro*, 136 S. Ct. 2117, 2126 (2016) (internal quotations and citations omitted).

have engendered serious reliance interests that must be taken into account."[6] It must offer a reasoned explanation for disregarding the facts and circumstances that underlay or were engendered by the prior policy.[7] An "unexplained inconsistency in agency policy is a reason for holding an interpretation to be an arbitrary and capricious change from agency practice," and a policy of this sort is unlawful and receives no *Chevron* deference.[8]

A. BPA Has Previously Rejected Most of the Arguments Made in This Proceeding for Eliminating the IM Rate.

In its initial proposal for the IM rate, BPA Staff "proposed no changes from the methodology used in previous rates cases, including BP-16."[9] In response, two parties – Renewable Northwest and Montana Environmental Information Center together with Sierra Club (collectively "MEIC") – advanced proposals to eliminate the IM rate. Similar proposals to eliminate the IM rate or to "roll in" the costs of the Eastern Intertie into BPA's Network segment[10] were made in BP-12, BP-14, and BP-16 rate cases, and were rejected each time. In fact, BPA Administrators previously rejected many of the specific arguments Renewable Northwest and MEIC advance in this proceeding in support of their proposals. No good reasons exist for reconsidering these arguments here and the Administrator should reject them outright.

1. <u>The Eastern Intertie Was Constructed for a Limited Purpose and Will Be Used Solely for That Purpose in the BP-18 Rate Period.</u>

Thomas J. Schneider, one of the witnesses for MEIC, argues that BPA played an extensive role in building and justifying the need for the Eastern Intertie facilities to the Montana

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[6] *Encino Motorcars*, 136 S. Ct. at 2126 (internal quotations and citations omitted).
[7] *Id*.
[8] *Id*.
[9] Fredrickson et. al., BP-18-E-BPA-26 at 2.
[10] For purposes of ratemaking, eliminating the IM rate and "rolling in" the costs of the Eastern Intertie are functionally equivalent – under either proposal, BPA would recover its share of Eastern Intertie costs in Network rates. Administrator's Final Record of Decision, BP-16 Rate Proceeding, BP-16-A-02 ("BP-16 ROD") at 122 (July 2015).

regulators. The fact that BPA was involved in the justification, development, or construction of the Eastern Intertie has no dispositive value in determining the proper segmentation for the facilities for cost recovery.[11] Besides, "BPA is involved in the justification for all transmission facilities that it constructs."[12]

Mr. Schneider further asserts that part of BPA's justification for the Eastern Intertie was the need to serve the Pacific Northwest, "including the rapidly growing loads of BPA's Montana cooperative customers."[13] Thus, Mr. Schneider reasons, the Eastern Intertie "is not an isolated segment" of BPA's transmission system, but rather "is and has always been part of BPA's regional transmission network."[14] Therefore, he argues, the IM rate should be eliminated. Mr. Schneider's assertions regarding the purpose and use of the Eastern Intertie are plainly contradicted by the well-established history of the Eastern Intertie and the record in this proceeding, and were previously rejected by the Administrator.

BPA and a group of investor-owned utilities that owns coal-fired generating facilities located in southeastern Montana ("Colstrip facilities") are parties to the Montana Intertie Agreement.[15] With the expansion of the Colstrip facilities in the 1970s and 1980s, the Colstrip owners needed additional transmission capacity to carry electricity generated at the Colstrip facilities to the west, where their customers were located.[16] The Colstrip owners took various steps to obtain the necessary capacity, including requesting that BPA construct 500 kV

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[11] Deen, BP-18-E-PP-02 at 12.
[12] Fredrickson et. al., BP-18-E-BPA-26 at 10.
[13] Schneider, BP-18-E-SC-01-V01 at 11.
[14] *Id*.
[15] *See* Fredrickson et. al., BP-18-E-BPA-26 at 10; BP-14 ROD at 176.
[16] *Pacific Power & Light Co. v. Montana Dept. of Revenue*, 773 P.2d 1176, 1179 (Mont. 1989), *cert. denied*, 493 U.S. 1050 (1990).

transmission lines west from Townsend to Garrison in Montana.[17] BPA agreed and ultimately completed the Eastern Intertie,[18] which has been used primarily to wheel Colstrip generation to loads in the Pacific Northwest.[19] BPA Staff have testified that providing service to BPA's preference customers was not among BPA's purposes for constructing the Eastern Intertie,[20] and they are not aware of the Eastern Intertie ever having been used to serve preference customer loads, including BPA's Montana cooperative customers.[21]

In the BP-14 proceeding, Renewable Northwest argued that the Eastern intertie is not a true intertie, but "an artificial segmentation that operates as an integrated part of BPA's transmission system."[22] In rejecting that argument, the Administrator concluded that the Eastern Intertie "is radial to BPA's Integrated Network, "is not an 'artificial segmentation,'" and "should be changed only with good reason."[23]

In setting rates, "BPA allocates the rate period transmission revenue requirement to the various transmission rates based on the projected use of the system."[24] Currently, "[t]here are no BPA customer loads served directly from the Eastern Intertie"[25] and that is not expected to change in the next rate period. BPA Staff "expect that the primary (and perhaps singular) use of the Eastern Intertie as a whole [will be] to transfer power from Colstrip to the Pacific Northwest during the BP-18 rate period."[26] The fact of the matter remains that the Eastern Intertie facilities

[17] *Pacific Power & Light Co.*, 773 P.2d at 1179; *Portland General Elec. Co. v. Montana Dept. of Revenue*, 773 P.2d 1189, 1192 (Mont. 1989), *cert. denied*, 493 U.S. 1049 (1990).
[18] *Pacific Power & Light Co.*, 773 P.2d at 1179.
[19] Fredrickson et. al., BP-18-E-BPA-26 at 8.
[20] Data Responses Admitted via BP-18-M-BPA-07, BP-18-E-BPA-53 at 602 (Response to Data Request SC-BPA-26-12).
[21] *Id.*; Fredrickson et. al., BP-18-E-BPA-26 at 11.
[22] BP-14 ROD at 175.
[23] *Id.* at 176.
[24] BP-12 ROD at 475.
[25] Fredrickson et. al., BP-18-E-BPA-26 at 9.
[26] Data Responses Admitted via BP-18-M-BPA-07, BP-18-E-BPA-53 at 601 (Response to Data Request SC-BPA-

were constructed to wheel power from Colstrip to the Pacific Northwest, and they have not, are not currently, and are not expected in the next rate period to be used for load service by BPA. Thus, BPA should continue to charge the IM rate for service on its capacity share of the Eastern Intertie.

2. The IM Rate Is Not an Impediment to Development of Montana Generating Resources.

Renewable Northwest argues that the IM rate adds more than $2 per MWh to the cost of Montana generating resources, making those resources less competitive when compared to resources that do not have to pay both the IM rate and a Network rate.[27] Likewise, Robert M. Fagan, a witness for MEIC, argues that eliminating the IM rate would "reduce the overall cost of delivering Montana wind to the BPA region load by $2.05/MWh," and "this incremental cost savings would make Montana wind more competitive with resources that currently do not have to pay additional pancaked rates to reach load."[28]

Beyond the fact that the IM rate would be an additional transmission charge for Montana generating resources, neither Renewable Northwest nor MEIC offer any support for their conclusion that eliminating the IM rate would make Montana resources more competitive. Indeed, Mr. Fagan readily admits that "[i]t is impossible to say with certainty that eliminating the Montana Intertie Rate will result in greater Montana wind development."[29] That is precisely why the Administrator previously rejected arguments that eliminating the IM rate would encourage renewable resource development in Montana, and the evidence in this proceeding does not support a different conclusion.

26-11); Fredrickson et. al., BP-18-E-BPA-26 at 9.
[27] Yourkowski, BP-18-E-RN-01 at 7-8.
[28] Fagan, BP-18-E-SC-02-V01 at 9.
[29] *Id.*

First, the $2-per-MWh charge added by the IM rate is negligible relative to the levelized cost of new wind resources in the region. According to the Northwest Power Planning Conservation Council's Seventh Power Plan, new wind resources in the region would have a levelized cost of energy between $94 and $110 per MWh.[30] "A $2-per-MWh charge is a relatively small component of this overall amount and is likely to be overwhelmed by other, more impactful considerations in choosing between projects."[31] The Administrator reached a similar conclusion in the BP-16 proceeding, noting that $2 per MWh "is a relatively small addition to the total cost of over $100/MWh [for delivered energy]."[32]

Second, Montana wind is fully competitive with other resources even including the IM rate. In comparing generating resources, the Seventh Power Plan analyzed five "reference" plants; four of the plants were located in Montana and one was located in the Columbia Gorge. "All four Montana plants came in with a lower levelized cost of energy than the Columbia Gorge plant, including the cost of transmission."[33] The fact that "even having to pay the IM rate, Montana wind generation has comparable or lower costs" was one of the other reasons the Administrator rejected the argument that eliminating the IM rate would make Montana wind more competitive.[34]

Third, Renewable Northwest and MEIC ignore the actual factors that likely impede the development of wind generation in Montana. As the Administrator noted in BP-16, although Montana's potential wind generation exceeds 9,000 MW, "the absence of available transmission capability in Montana and on BPA's Network would make large-scale wind development

[30] Deen, BP-18-E-PP-02 at 6 (citations omitted).
[31] *Id.* at 6-7.
[32] BP-16 ROD at 124.
[33] Deen, BP-18-E-PP-02 at 7 (citation omitted).
[34] BP-16 ROD at 124.

unlikely."[35] BPA has 184 MW of available transmission capacity on the Eastern Intertie. Even assuming that Montana wind generation could get to BPA's Network using another transmission provider, which is unlikely, BPA's Network is constrained over the West of Garrison and West of Hatwai flowgates. BPA Staff testified that the West of Garrison flowgate "currently has zero long-term firm available transfer capability," and the West of Hatwai flowgate "is similarly constrained."[36] Given these transmission constraints, it is unlikely that eliminating the IM rate would encourage renewable resource development in Montana.

3. <u>Eliminating the IM Rate Is Not Likely to Result in Additional Sales Over the Eastern Intertie, but Would Expose Network Customers to Massive Costs in Violation of Cost-Causation Principles.</u>

Renewable Northwest and MEIC argue that by eliminating the IM rate and making Montana wind more competitive, BPA "would be better off" because it would be more likely that BPA's 184 MW of unsubscribed capacity on the Eastern Intertie will be sold.[37] They argue that the rate impact on BPA's Network transmission customers would be "minimal"[38] or "de minimis."[39] As discussed above, the absence of available transmission capability from Montana makes large-scale wind development – and subscription of the remaining Eastern Intertie capacity – unlikely.

As in past rate cases, arguments about "de minimis" rata impacts ignore the *real* costs of rolling in the IM rate and accommodating additional wind development. The Administrator previously observed that "the real rate impacts would result from transmission upgrades and

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35 BP-16 ROD at 125.
36 Fredrickson et. al., BP-18-E-BPA-26 at 6.
37 Yourkowski, BP-18-E-RN-01 at 13-14; Fagan, BP-18-E-SC-02-V01 at 10.
38 Fagan, BP-18-E-SC-02-V01 at 6.
39 Yourkowski, BP-18-E-RN-01 at 13.

balancing capacity, which would be needed to support more wind development."[40] BPA Staff testified that BPA may need to reinforce the West of Garrison flowgate, the West of Hatwai flowgate, and other parts of its transmission system depending on the parameters of the service requested.[41] The costs to the Network customers for these and other transmission upgrades and balancing capacity that would be needed to move a significant amount of wind generation from Montana to the BPA Network "could easily be measured in the hundreds of millions to more than a billion dollars."[42] Under the principle of cost causation, entities that create the costs should bear the responsibility for paying those costs. Eliminating the IM rate would expose BPA's Network customer to a variety of upgrade and service costs they did not cause and without commensurate benefits, in violation of the cost causation principle.[43]

BPA Staff testified that there are a myriad of other issues that need to be addressed holistically before the IM rate is eliminated:

> We continue to have concerns associated with service from Montana including balancing capacity issues, allocation of costs of potential reinforcements to provide transmission service to new renewable generation in Montana, scheduling and reservation system changes and associated costs, contract issues involving the Montana Intertie Agreement, and possible additional investments (RAS/build) needed to enable service. Most of these issues need to be addressed outside of the rate case and require a discussion with parties to the Montana Intertie Agreement, as well as other stakeholders. Many of these issues were identified in the BP-16 case and were the basis for the Administrator's decision not to eliminate the IM rate in that case.[44]

In addition, elimination of the IM rate "could be viewed as a precedent for arguments to roll in BPA's Southern Intertie Segment."[45] Both the Southern Intertie and the Eastern Intertie are used

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[40] BP-16 ROD at 125.
[41] Fredrickson et. al., BP-18-E-BPA-26 at 6.
[42] Deen, BP-18-E-PP-02 at 10.
[43] BP-12 ROD at 492 (stating that "BPA's expressed policy is to avoid significant cost shifts").
[44] Fredrickson et. al., BP-18-E-BPA-26 at 13.
[45] Deen, BP-18-E-PP-02 at 10.

primarily for transporting energy to and from locations that are remote to BPA's Network and the Pacific Northwest. "Given the trajectory of non-dispatchable renewables development in California, there may soon come a time when there is substantial demand for the export of renewable energy from California to the Northwest."[46] Arguments that eliminating the IM rate would facilitate renewable energy imports could be used in the context of the Southern Intertie, to the detriment of Network customers and contrary to the purpose for segmenting those facilities. Although roll-in of the Southern Intertie was not at issue in the BP-16 proceeding, the Administrator noted that rolling in the Southern Intertie would produce a 12.5 percent Network rate increase, which "could result in rate instability and rate shock."[47] Because eliminating the IM rate is likely to expose Network customers to substantial costs and risks creating a precedent for additional costs, the Administrator should retain the IM-18 rate.

4. BPA's IM Rate Design Is Based on BPA's Longstanding Segmentation Methodology and Is Consistent with its Statutory Obligations and FERC Policy.

Renewable Northwest argues that the "IM rate pancake" is inconsistent with (1) Federal Energy Regulatory Commission's (FERC) "or" pricing policy because Eastern Intertie transmission customers pay both the Network rate and the IM rate, and (2) with sound business principles because it discourages utilization of BPA's full Eastern Intertie capacity.[48] FERC's "or" pricing policy allows transmission provider to charge the higher of an incremental cost or embedded cost rates, but not both.[49] BPA's IM rate design follows its segmentation methodology, which has passed muster with BPA Administrators, the FERC, and the courts time

[46] Deen, BP-18-E-PP-02 at 10.
[47] BP-16 ROD at 125.
[48] Yourkowski, BP-18-E-RN-01 at 11-12.
[49] *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act*, Order on Reconsideration and Clarifying Policy Statement, 71 FERC ¶ 61,195, at p. 61,690 (1995).

and time again. Thus, arguments that BPA's IM rate design violates FERC policies or BPA's statutory obligations have no merit.

As discussed above, BPA has separately segmented the Eastern Intertie since the 1983 rate case because it was a radial line built by BPA primarily to transmit Colstrip generation to BPA's Network.[50] BPA Staff testified that they still "consider the use of BPA's Eastern Intertie facilities to be a separate and distinct use of the transmission system from use of the Network system."[51] Indeed, for the BP-18 rate period, BPA Staff "expect that the primary use of the Eastern Intertie will continue to be wheeling the output of Colstrip to BPA's Network starting at Garrison," thus maintaining the segment's distinct purpose.[52]

In setting rates, BPA allocates the rate period transmission revenue requirement to various transmission rates based on projected use of the system. Because the entire system is not needed to provide each type of service, this method of cost allocation is equitable and consistent with sound business principles.[53] Given that the Eastern Intertie and the Network have distinct uses, BPA Staff have calculated separate and distinct embedded costs for each segment and used those costs to set rates for each segment.[54] Thus, because "the rates recover the costs of *different* facilities, they are intrinsically not duplicative," and because the rates are set based on embedded costs of each segment, "they are inherently not excessive."[55] By definition, BPA cannot and does not "double" recover its costs from either segment. Therefore, it does not violate FERC's pricing guidelines or its statutory requirement to offer the lowest possible rates consistent with sound business principles.

[50] BP-12 ROD at 479.
[51] Fredrickson et. al., BP-18-E-BPA-26 at 12.
[52] *Id*.
[53] *See* BP-12 ROD at 475.
[54] Fredrickson et. al., BP-18-E-BPA-26 at 12; Deen, BP-18-E-PP-02 at 6.
[55] Deen, BP-18-E-PP-02 at 6.

B. Renewable Northwest Presents No Compelling New Evidence for the Administrator to Reverse BPA's Prior Decisions.

Renewable Northwest claims that circumstances "have changed significantly since the BP-16 ROD, warranting elimination of the IM rate in this proceeding."[56] Specifically, Renewable Northwest cites two changes: (1) Oregon's passage of the Clean Electricity and Coal Transition Plan ("CECTP"), which increases Oregon's Renewable Portfolio Standard to 50 percent by 2040 and requires investor-owned utilities to shed coal generation assets from their rate base by 2035, and (2) an agreement was reached requiring Colstrip units 1 and 2 to retire no later than July 1, 2022.[57] Renewable Northwest further asserts that it became aware since BP-16 that the IM rate and the TGT rate "are not cost-based."[58]

1. <u>Planned and Future Closures of Colstrip Facilities Are Unlikely to Have Any Revenue Impact on BPA During the BP-18 Rate Period.</u>

Renewable Northwest argues that the closure of Colstrip facilities, whether on account of Oregon's passage of CECTP or the planned retirement of Units 1 and 2, will reduce the transmission sales and revenues over the BPA Network.[59] It argues that eliminating the IM rate would encourage both the full subscription of the Eastern Intertie and the use of BPA Network capacity freed up by the retirements.[60] Renewable Northwest's assertions are based on speculative assumptions[61] and present no valid concerns.[62] Even MEIC concedes that "[i]t is impossible to say with certainty that eliminating the Montana Intertie Rate will result in greater Montana wind development or full subscription of BPA's share of the Eastern Intertie."[63]

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[56] Yourkowski, BP-18-E-RN-01 at 4.
[57] *Id.*
[58] *Id.*
[59] *Id.* at 5-6.
[60] *Id.*
[61] Fredrickson et. al., BP-18-E-BPA-26 at 7.
[62] Deen, BP-18-E-PP-02 at 8.
[63] Fagan, BP-18-E-SC-02-V01 at 9.

First, as discussed above, "eliminating the IM rate would have no bearing on the economic viability of the Eastern Intertie capacity,"[64] and given the serious transmission constraints for exporting out of Montana, is unlikely to encourage renewable resource development in Montana. Second, there is no evidence that Colstrip Units 1 and 2 or any other Colstrip facilities will be shut down during this rate period. It would be impudent for the Administrator to change the agency's longstanding segmentation and rate design methodology for the Eastern Intertie based on the speculations that Colstrip Units 1 and 2 *might* retire before their planned closure by 2022 and their retirement *might* impact BPA's revenues.

Third, evidence in the record does not support Renewable Northwest's claim that BPA's Network revenues would be substantially reduced by the closure of Colstrip facilities. First, BPA Staff testified that "BPA currently has approximately 1,191 megawatts in its transmission service queue requesting service from Montana across BPA's Network that may be able to use the capacity that might become available by unit retirements at Colstrip."[65] Second, customers delivering or purchasing the output of Colstrip facilities would still need to serve their native load and may replace the Colstrip generating capacity with other resources that continue to utilize BPA's Network.[66] If they do, closure of Colstrip units would have no impact on BPA's revenues. If they do not, BPA could simply remarket the freed-up capacity given the depth of its current queue. Third, even if any Colstrip facilities retired early and before the scheduled termination of the Montana Intertie Agreement in 2027, the Montana Intertie Agreement protects BPA from cost exposure.[67] Finally, depending on what Colstrip transmission customers may do with their rights following closure of their facilities, there could be contractual and policy

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[64] Deen, BP-18-E-PP-02 at 8.
[65] Fredrickson et. al., BP-18-E-BPA-26 at 7.
[66] *Id.*; Deen, BP-18-E-PP-02 at 8-9.
[67] Fredrickson et. al., BP-18-E-BPA-26 at 8.

considerations that would be further complicated by BPA's premature action. In summary, BPA Staff characterized Renewable Northwest's argument the best: it "involves a significant amount of speculation; it is too early to know if BPA's Network revenues will be impacted by retirements at Colstrip."[68]

2. <u>Renewable Northwest's Claim That BPA's IM and TGT Rates Are Not Cost-Based Has No Merit.</u>

Renewable Northwest claims that it recently learned that the TGT rate alone – a formula rate based on the Montana Intertie Agreement and intended to recover BPA's costs of the Eastern Intertie facilities[69] – collects approximately $1 million more in revenue than the $11.718 million it costs BPA to own and operate the Eastern Intertie.[70] This "disconnect between BPA's Eastern Intertie revenue requirement and the amount BPA is charging the TGT rate," according to Renewable Northwest, demonstrates that the IM rate is not cost-based.[71] However, BPA's IM rate and TGT rates are set to recover BPA's actual costs and therefore, are cost-based by definition. Renewable Northwest's argument has no merit.

First, as BPA Staff explained in their testimony, "[t]here are multiple methods for identifying costs on which to base rates; using the segmented revenue requirement is just one such method, as is using the costs specified in a contract."[72] Specifically, the actual costs of building and maintaining the Eastern Intertie are recovered by contract from the Colstrip parties through the TGT rate. Thus, BPA is appropriately collecting the revenues to which it is entitled.[73] Second, contrary to Renewable Northwest's claim, there is no "surplus" generated by

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[68] Fredrickson et. al., BP-18-E-BPA-26 at 7-8.
[69] Transmission Rates Study and Documentation, BP-18-E-BPA-08 at 60.
[70] Yourkowski, BP-18-E-RN-01 at 9-10.
[71] *Id.* at 10.
[72] Fredrickson et. al., BP-18-E-BPA-26 at 6.
[73] Deen, BP-18-E-PP-02 at 3; Fredrickson et. al., BP-18-E-BPA-26 at 6.

the TGT rate because to the extent that revenues BPA collects from the TGT rate in any particular year exceed the costs of the Eastern Intertie facilities as set by the Montana Intertie Agreement, those revenues are actually accounted for in the computation of annual costs for succeeding years.[74] BPA Staff explained that "[t]he reason for doing so is to be sure that revenues match costs over time."[75]

Second, the IM rate, like the TGT rate, is set to recover the actual costs of BPA's firm capacity requirements (in this case 16 MW out of a possible 200 MW) on the Eastern Intertie.[76] Finally, to the extent there are surplus revenues from the TGT rate and the IM rate in any particular year, it is appropriate for those revenues to be allocated to the benefit of other segments in that year because those segments would have to pay for any potential deficit in Eastern Intertie revenues.[77] The bottom line is that "[b]ecause BPA's proposed rates are based on the actual costs of the Eastern Intertie, both the TGT and the IM rates are appropriate and cost-based"[78] and the Administrator should reject Renewable Northwest's claim to the contrary.

III. CONCLUSION

For the reasons presented above, PPC urges the Administrator to reject proposals to eliminate the IM rate, and maintain the Eastern Intertie as a separate segment for ratesetting purposes.

Respectfully submitted this 2nd day of May, 2017.

s/ Irene A. Scruggs
Attorney for PPC

[74] Data Responses Admitted via BP-18-M-BPA-07, BP-18-E-BPA-53 at 21 (Response to Data Request PP-BPA-26-61).
[75] *Id.*
[76] Deen, BP-18-E-PP-02 at 3.
[77] *Id.* at 4.
[78] *Id.*

Post-Hearing Exhibit List of Public Power Council

Exhibit	Document Title	Date Filed	Status
BP-18-E-PP-02	Rebuttal Testimony of PPC	3/14/17	Admitted
BP-18-Q-PP-03	Qualification Statement of Michael Deen	1/23/17	Admitted
BP-18-M-BPA-07	Joint Motion to Admit Certain Data Request Responses Into Evidence	4/5/17	Admitted
BP-18-E-BPA-53	Data Responses Admitted via BP-18-M-BPA-07	4/21/17	Admitted

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing on the Bonneville Power Administration's Office of General Counsel, the Hearing Clerk, and all litigants in this proceeding by uploading it to the BP-18 Rate Case Secure Website pursuant to BP-18-HOO-02 and BP-18-HOO-05.

DATED: May 2, 2017.

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

Fiscal Years 2018-2019 Proposed	**)**	**BPA Docket No. BP-18**
Power and Transmission Rate	**)**	
Adjustment Proceeding	**)**	

INITIAL BRIEF OF:

PUBLIC POWER COUNCIL

and

POWEREX CORP.

as

JOINT PARTY 1

SUBJECT: SOUTHERN INTERTIE HOURLY RATES

May 2, 2017

INITIAL BRIEF OF JOINT PARTY 1

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INITIAL BRIEF OF JOINT PARTY 1

SUBJECT: Southern Intertie Hourly Rates

The Public Power Council ("PPC") and Powerex Corp. ("Powerex"), together designated as Joint Party 1 ("JP01"), file this initial brief regarding Bonneville Power Administration's ("BPA") proposed rates for hourly service on the Southern Intertie. This initial brief follows the direct and rebuttal testimony filed by JP01 (BP-18-E-JP01-01 and BP-18-E-JP01-02) in support of BPA Staff's proposal to revise the Southern Intertie hourly rates (BP-18-E-BPA-12 and BP-18-E-BPA-25) in response to concerns about the ability of BPA to recover the costs of the Southern Intertie segment.

I. EXECUTIVE SUMMARY

JP01 urges the Administrator to adopt BPA Staff's proposal, broadly supported by BPA's customers, to increase the hourly rates on the Southern Intertie. The appeal of long-term firm ("LTF") service on the Southern Intertie has been declining. A key cause of this decline is the market design of the California Independent System Operator ("CAISO"), which grants awards for deliveries into its market without regard to the seller's transmission priority under BPA's Open Access Transmission Tariff ("OATT"). Thus, sellers into the CAISO market can rely on hourly service at lower total cost, avoiding the long-term commitment and cost associated with LTF service. This "seam" created by the different transmission rules, together with the more recent reduction in the number of hours of peak net demand in California, have diminished the value of LTF service, as reflected in customer input during BPA Staff's extensive regional stakeholder process and as manifested in the shrinking queue for LTF service on the Southern Intertie.

Facing this precipitous decline in the queue and concerns about customers' willingness to invest in LTF service, BPA Staff proposed to update a single number in the formula used to set the hourly rates on the Southern Intertie to reflect current demand patterns in California. Demand in California has been affected by increasing amounts of solar generation that reduces net load in the middle of the day, which has shifted and reduced the number of high-value hours for imports into California to just 5 hours in the evening peak. By updating the existing assumption of 16 heavy load hours to 5 hours in its formula, BPA will increase the Southern Intertie hourly rate and re-incentivize customers to purchase LTF service. This incentive will improve the likelihood of BPA's continued cost recovery on the Southern Intertie, in accordance with its statutory requirements.

II. IDENTITIES AND INTERESTS OF JOINT PARTY 1

Public Power Council's members are BPA's preference customers that purchase network transmission service for delivery of power. PPC members pay for long-term firm capacity that BPA Power Services holds on the Southern Intertie. PPC members also pay for BPA Power Services' short-term transmission purchases on the Southern Intertie. PPC members pay the costs of these transmission products through BPA's power rates.

Powerex markets power exported from the surplus capability of the predominantly hydropower generation facilities of its parent the British Columbia Hydro and Power Authority. Powerex also markets power from its own portfolio of third-party power purchases. Powerex sells and purchases power throughout the Western Interconnection, including in the CAISO organized markets and with bilateral customers in California. Powerex is one of BPA's largest transmission customers, and has invested in substantial LTF transmission reservations on the Southern Intertie.

III. BPA STAFF'S PROPOSAL IS AN APPROPRIATE REMEDY TO BPA'S RISK OF UNDER-RECOVERY ON THE SOUTHERN INTERTIE

Statutory directives mandate that BPA set its rates in accordance with sound business principles to recover the costs of transmission of electric power.[1] These directives focus on cost recovery but do not restrict the Administrator to any particular rate design methodology because the Administrator has broad discretion in implementing the statutory ratemaking directives.[2] Indeed, the Ninth Circuit Court of Appeals has been clear that BPA is entitled to deference in ratemaking decisions, even where BPA may be perceived to have an economic interest in the outcome.[3]

A. Changes in California Have Put in Jeopardy BPA's Ability to Recover the Costs of the Southern Intertie Segment

BPA Staff testified that "BPA depends on sales of long-term firm service to recover the majority of the costs of the Southern Intertie."[4] This is a key principle in this proceeding. BPA Staff also testified that the agency is facing termination of a "significant amount of its existing contracts for long-term firm service on the Southern Intertie."[5] Given BPA's reliance on sales of long-term firm transmission service to recover the costs of the Southern Intertie segment, BPA Staff are rightly concerned that the agency is at risk of under-recovering its costs in the BP-18 rate period and that the risk "has increased since the BP-16 rate case" to the point that a change to the hourly rates "is necessary."[6] Indeed, during the upcoming BP-18 rate period nearly half of existing

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[1] Pacific Northwest Electric Power Planning and Conservation Act, § 7(a)(1), 16 U.S.C. § 839e(a)(1) (2012); Federal Columbia River Transmission System Act § 9, 16 U.S.C. § 838g (2012).
[2] *Pub. Power Council v. Bonneville Power Admin.*, 442 F.3d 1204, 1209 (9th Cir. 2006) (citation omitted).
[3] *California Energy Com'n v. Bonneville Power Admin.*, 909 F.2d 1289 (9th Cir. 1990) (citation omitted); *see also Bonneville Power Admin.*, 147 FERC ¶ 61,053 at PP 9-11 (2014) (stating that FERC's review of BPA's rates is limited to determining whether the proposed rates comply with the three prongs of Section 7(a)(2) of the Northwest Power Act and stating that FERC's role is appellate in nature: affirming or remanding the rates submitted for review).
[4] *Fredrickson et al.*, BP-18-E-BPA-12 at 4. For simplicity, reference to and discussion of transmission services herein refers to service on BPA's Southern Intertie segment, unless otherwise noted.
[5] *Id.*
[6] *Id.*

LTF service on the Southern Intertie will terminate unless customers decide to renew their service,[7] and since September of 2014, the requests for new LTF service have decreased by 5,226 MW.[8] These figures, along with customer feedback that LTF service on the Southern Intertie is not as attractive as it once was, have BPA Staff "concerned" that this might be "the start of [a] trend where customers with pending requests are rejecting offers of long-term firm service."[9]

The decreased demand for Southern Intertie LTF service and the growing risk of under-recovery in the BP-18 rate period is driven primarily by two external factors. First, integration of large amounts of solar generation has changed the daily net load shape in California.[10] The change in the daily net load shape has reduced the demand for imports during the afternoon, which has effectively reduced the number of daily high-value hours from 16 (the traditional "heavy load hours") to just a handful of hours in the early evening.[11] Not only is this a current trend, but BPA Staff testified that "BPA anticipates that the trend of decreasing net load in the middle of the day will continue."[12] The now obsolete assumption of 16 heavy load hours was the basis of BPA's Southern Intertie hourly rate in the BP-16 rate proceeding.[13]

Second, California market rules have further reduced the incentive for BPA customers to purchase LTF transmission on the Southern Intertie under the current rate structure. Under the OATT framework, congestion is resolved according to priority of transmission service: firm reservations flow ahead of non-firm reservations.[14] On the Southern Intertie, however, congestion is largely resolved by the CAISO.[15] Uniquely, the CAISO day-ahead market, where most of the

[7] *Id*. at 8.
[8] *Id*. at 7.
[9] *Id*. at 8.
[10] *Id*. at 4-5.
[11] *Id*.
[12] *Id*. at 5.
[13] *Id*. at 4-5.
[14] *Deen and Wellenius*, BP-18-E-JP01-01 at 5.
[15] *Id*.

generation needed to meet California demand is acquired, "does not require that participants have firm transmission to submit a bid to sell into the market, nor does the market consider the difference in transmission priority between firm and non-firm transmission when awarding bids."[16]

In other words, customers can reserve non-firm service on BPA's Southern Intertie and flow ahead of customers who made long-term investments in firm service. This allows customers to bid into CAISO's day-ahead market without purchasing BPA transmission, acquire the lower-cost non-firm transmission only for the hours in which they receive a day-ahead award, and flow ahead of customers with firm transmission.[17] This, in turn, is likely to preclude customers who invested in LTF service on the Southern Intertie from being able to schedule up to their full rights.[18] In essence, the current CAISO rules, coupled with the relatively low BP-16 hourly rate, allow sellers to use hourly non-firm transmission service to 'cherry pick' the reduced number of high-value hours at significantly lower total cost than is paid by LTF customers.[19] Naturally, this practice "reduces the incentive to purchase long-term firm under the current rate structure."[20]

B. BPA Staff's Rate Proposal Appropriately Responds to the Changes in California and Strengthens Incentives for Customers to Invest in LTF Service

In response to these seams issues, BPA Staff have proposed to update the formula BPA used in BP-16 rate proceeding and calculate the hourly rates on the Southern Intertie "to reflect that the number of heavy load hours has been reduced due to changes of the generation mix in

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[16] *Fredrickson et al.*, BP-18-E-BPA-12 at 5. A similar concerns arises for deliveries to California markets other than CAISO due to the downstream transmission provider establishing priority pursuant to its own scheduling priorities, not BPA's.
[17] *Id*. at 5-6; *Deen and Wellenius*, BP-18-E-JP01-01 at 5.
[18] *Deen and Wellenius*, BP-18-E-JP01-01 at 5; 14 (explaining that BPA resells as non-firm service the firm transmission capacity on the Southern Intertie that has been reserved but not scheduled, thus customers that receive an award from the CAISO can anticipate that non-firm transmission will become available and effectively prevent long-term firm customers from scheduling on their reservations).
[19] *Id*. at 5; *see also Fredrickson et al*., BP-18-E-BPA-12 at 6.
[20] *Fredrickson et al*., BP-18-E-BPA-12 at 6; *see also Deen and Wellenius*, BP-18-E-JP01-01 at 5-6.

California."[21] Specifically, instead of continuing to rely on the outdated figure of 16 heavy load hours per day or 80 hours per week, BPA Staff propose to use the more current figure of 5 hours per day or 25 hours per week.[22] This is because the changes in California's generation mix "have effectively decreased the number of heavy load hours in California to 25 hours per week."[23] Under BPA Staff's proposal, the rate for hourly firm and non-firm service would increase to 11.49 mills per kWh.[24]

Other than accounting for the reduction in California's heavy load hours, BPA Staff maintained the same fundamental rate design and cost-based rate methodology that BPA used in BP-16 and prior cases. The objective behind the rate remains the same: "to ensure that customers that decide to reserve transmission only during the periods when California net loads are the highest pay the same amount as long-term firm customers that have the right to schedule transmission 24 hours a day."[25] Under Staff's proposal, long-term and short-term users of the Southern Intertie would equitably contribute to the cost of service on the Southern Intertie because customers that reserve 1 MW of hourly transmission during the 25 high-value hours per week would pay the same as customers purchasing 1 MW of long-term firm transmission. Thus, BPA Staff's proposal equitably allocates the costs of the Southern Intertie to the users of that segment while adjusting for the practical circumstances affecting the use of that segment.

BPA Staff's proposal helps to restore the incentive for customers to continue to invest in LTF transmission service, thus protecting BPA's ability to recover the costs of the Southern Intertie segment. There are three broad reasons for customers to invest in LTF service under the

[21] *Fredrickson et al.*, BP-18-E-BPA-12 at 9.
[22] *Id.*
[23] *Id.* at 10.
[24] *Id.*
[25] *Id.* at 9.

OATT framework instead of relying on hourly non-firm service.[26] First, reserving LTF service secures transmission service, which may or may not be available on an hourly basis. Second, LTF service generally provides higher scheduling priority than hourly non-firm service. And third, depending on how many hours the customer schedules on its transmission reservation, LTF may be more cost-effective than hourly service. While these reasons encourage transmission customers to invest in LTF service in most cases, as a result of the seams issues, *none* of these reasons currently applies on the Southern Intertie.

BPA Staff's proposal is specifically designed to restore the financial incentive for transmission customers to continue to invest in LTF service on the Southern Intertie instead of relying on hourly service.[27] Under the current BP-16 rates, LTF service on the Southern Intertie is more financially attractive than the hourly service only if a customer intends to schedule on its LTF reservation in more than 80 hours per week (16 hours per day, 5 days per week). Under BPA Staff's proposed hourly rate, customers that reserve hourly non-firm transmission in 25 hours per week (5 hours per day, 5 days per week) would pay the same amount as LTF customers that have the right to schedule transmission in any hour of the year. Thus, customers that intend to schedule on their transmission reservation in more than 25 hours per week have a financial incentive to invest in the LTF product. Indeed, maintaining the financial incentive for customers to continue to invest in LTF service, which BPA uses to recover the majority of costs of the Southern Intertie segment, was precisely the intent of BPA Staff's proposal.[28]

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[26] *Deen and Wellenius*, BP-18-E-JP01-01 at 14.
[27] *Id*. at 15-16.
[28] *Fredrickson et al*., BP-18-E-BPA-12 at 8; BP-18-E-JP01-03 at 2 (Response to Data Request PP-BPA-26-62)("BPA staff is proposing modifying its rate design to incent customers to continue to take long-term firm service on the Southern Intertie and reduce the risk of under recovery").

IV. THE ADMINISTRATOR HAS SUBSTANTIAL EVIDENCE TO ADOPT STAFF'S SOUTHERN INTERTIE PROPOSAL

A. Ample Objective Evidence in This Record Supports BPA Staff's Proposal, Including Information from BPA Staff's Extensive Regional Stakeholder Process

The Northwest Power Act provides that the Administrator shall make a final decision establishing rates based on the record developed in the rate case proceeding and his decision shall include a complete justification of the final rates.[29] In basing his decisions on the rate case record, the Administrator necessarily weighs the evidence presented to determine whether it is adequate to support a particular conclusion.[30] As demonstrated below, the Administrator has compelling and substantial evidence to adopt BPA Staff's proposal.

To provide relevant background, in the BP-16 Final Record of Decision the Administrator noted his belief "that seams issues exist and must be addressed."[31] However, the Administrator was reluctant to adopt a ratemaking solution in that case until the agency could "seek clarity on the extent of the issue, conduct a broader examination of seams issues with the involved parties, and evaluate both ratemaking and non-ratemaking solutions."[32] Although the Administrator acknowledged customers' concerns that BPA was at risk of losing revenues in the future, the Administrator determined there was not sufficient evidence in that record to warrant adoption of a ratemaking solution.[33] Indeed, in the BP-16 rate proceeding, BPA Staff had testified that despite the CAISO's market rules, "the Southern Intertie remains fully subscribed in the southbound direction, and BPA has a long queue of customers waiting for capacity."[34] Nonetheless, the

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[29] 16 U.S.C. § 839e(5).
[30] Administrator's Final Record of Decision, BP-14 Power and Transmission Rate Proceeding, BP-14-A-03, at 13 (July 2013).
[31] Administrator's Final Record of Decision, BP-16 Power and Transmission Rate Proceeding, BP-16-A-02 ("BP-16 ROD"), at P-2 (July 2015).
[32] *Id*. at P-2, 112.
[33] *Id*. at 111-112.
[34] *Id*. at 111 (citing *Linn et al.*, BP-16-E-BPA-31 at 4); *see also Fredrickson et al.*, BP-18-E-BPA-12 at 6.

Administrator committed the agency to hold a series of workshops to explore the seams issues raised by the customers, as well as potential rates and non-rates options to address the issues.[35]

1. Evidence Gathered, Analyzed, and Presented by BPA Staff

Much has changed since the BP-16 rate case. BPA Staff testified here that it "is no longer the case" that "'the Southern Intertie remains fully subscribed'" or that "'BPA has a long queue of customers waiting for capacity.'"[36] In fact, BPA Staff testified that since BP-16, "the amount of megawatts in the queue is greatly reduced, and some customers are choosing not to accept new offers of long-term service," which "could be due in part to the CAISO's market rules."[37] What has also changed since BP-16, according to BPA Staff, "is [its] analysis on the Southern Intertie regarding the duck curve, intertie loadings, and California net load data that indicates a fundamental shift away from the traditional definition of 'on-peak' hours."[38]

BPA Staff did not arrive at these conclusions suddenly or without good basis. Following the conclusion of the BP-16 rate proceeding and true to the Administrator's commitment, BPA conducted an extensive regional consultation process "to see what actions (if any) it should take to make sure [LTF] service on the Southern Intertie remains viable and its customers receive an equitable share of the economic benefits provided by the Southern Intertie."[39] As part of the process, BPA Staff conducted many publicly-noticed workshops. There, BPA Staff made and encouraged interested parties to make presentations, analyzed and encouraged stakeholders to analyze available data, and evaluated a variety of rate alternatives. BPA Staff's regional

[35] *Id*. at 112.
[36] *Fredrickson et al*., BP-18-E-BPA-12 at 6 (citing the BP-16 ROD at 111).
[37] *Id*. at 6.
[38] *Linn et al*., BP-18-E-BPA-25 at 10-11.
[39] BP-18-E-JP01-03 at 14 ("Presentation and Analysis of Southern Intertie Hourly Non-Firm Alternatives," Regional White Paper, February 16, 2016); *see also Linn et al*., BP-18-E-BPA-25 at 5-6.

consultation process culminated in the publication of a Regional White Paper on the issue, following several rounds of stakeholder meetings and opportunities for written comments.[40]

One objective of BPA's regional consultation process was "to allow customers and stakeholders to communicate their views and interests directly to BPA in public forum."[41] A broad variety of BPA's customers, including public power, power marketers, and renewable energy developers, took the opportunity to express their growing concerns that LTF transmission rights on the Southern Intertie no longer had the value they once had, and for that reason, they would not renew LTF service or would remove their requests for new LTF service from the queue.[42] The foregoing concerns were raised not just by Powerex, but also by Tacoma Power, Morgan Stanley, Avangrid Renewables, Northwest Requirements Utilities, PPC, and the Industrial Customers of Northwest Utilities, among others.[43] This collection of stakeholders represented a broad spectrum of BPA's customer base.[44]

In fact, a presentation made by FTI Consulting as part of the regional consultation process, which is now part of the record in this proceeding, offered uncontroverted evidence that in the past several years, the seams issues on the Southern Intertie (1) harmed customer investment in BPA's LTF service; (2) reduced demand for BPA's LTF service; (3) increased reliance on hourly non-firm service; and (4) put BPA at risk of under-recovering its costs.[45] Notably, no members of Joint Party 3 ("JP03") – the only party now opposing BPA Staff's proposal – chose to participate in BPA's regional consultation process.[46]

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[40] *See* BP-18-E-JP01-03; *see also Deen and Wellenius*, BP-18-E-JP01-01 at 17.
[41] *Linn et al*., BP-18-E-BPA-25 at 5.
[42] *See id*. at 5-6.
[43] *Id*. at 6.
[44] *Id*.
[45] BP-18-E-JP03-13 ("Seams Issues on BPA's Southern Intertie," FTI Consulting Presentation at 20 (September 29, 2015)), admitted by BP-18-HOO-31.
[46] Sacramento Municipal Utility District ("SMUD"), now a member of JP03, submitted comments in August 2016, well after the public stakeholder process had concluded.

Ultimately, BPA Staff concluded in the Regional White Paper that: (1) BPA needs to take actions to protect the value of LTF transmission service on the Southern Intertie; (2) "a bundle of rate and non-rate solutions would be most effective;" and (3) "[i]n the BP-18 Initial Rate Proposal, BPA will propose a new methodology for the [hourly non-firm Southern Intertie] rate" supported by the factors examined during the consultation process.[47] BPA's complete White Paper is part of the record in this proceeding.[48] Following the conclusion of the regional consultation process and prior to the commencement of this proceeding, BPA held pre-rate case workshops focusing on the particulars of BPA Staff's expected rate proposal and, once again, inviting customers to comment.[49]

The entirety of the work done since the conclusion of the BP-16 rate proceeding led BPA Staff to believe that the agency must address the seams issues on the Southern Intertie with a targeted rate solution. Specifically, BPA Staff testified that the objective evidence they presented in this case regarding the net load in California (i.e., the "duck curve") and intertie loadings, in combination with customers' statements about the reduction in the size of the queue and LTF rights renewals, led BPA Staff to conclude that they should change how BPA calculates hourly rates on the Southern Intertie.[50] JP03, having not attended the agency's extensive consultation process, now urges the Administrator to ignore the conclusions of that process and decide the issue in JP03's favor.

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[47] BP-18-E-JP01-03 at 90 ("Presentation and Analysis of Southern Intertie Hourly Non-Firm Alternatives," Regional White Paper, at 77 (February 16, 2016)).
[48] *Id*. at 14.
[49] *Linn et al*., BP-18-E-BPA-25 at 5.
[50] *Id*. at 10-11.

2. Evidence Gathered, Analyzed, and Presented by JP01

PPC and Powerex are rate case parties with a joint interest in ensuring that BPA appropriately recovers the costs of the Southern Intertie facilities from the users of those facilities. PPC and Powerex were among the parties in BP-16 warning the agency of the declining value of LTF service on the Southern Intertie and the agency's increasing risk of under-recovery of the embedded costs of the Southern Intertie. They were also among the customers participating in the agency's regional consultation process and BPA's pre-rate case workshops. JP01 submitted direct and rebuttal testimony in this proceeding in support of BPA Staff's proposal.

In its testimony, JP01 presented independent evidence that BPA Staff's concerns regarding the value and future sales of LTF service on the Southern Intertie are amply supported by objective public data.[51] As discussed in more detail below, JP01 witnesses cited specific growing evidence of declining customer demand for LTF service on the Southern Intertie: (1) BPA's queue for new LTF service has declined sharply; (2) customers have withdrawn their requests from the queue; (3) customers have declined to renew expiring LTF service; and (4) customers have rejected offers of LTF service when it was offered by BPA.[52] Based on that evidence, JP01 concluded that BPA Staff is "correct" to propose corrective rate measures to strengthen incentives for customers to choose LTF service on the Southern Intertie.[53]

In addition, JP01 expert witnesses analyzed BPA Staff's specific rate proposal and concluded that it is cost-based and consistent with BPA's longstanding rate design methodology.[54] In fact, having independently analyzed the changes in California, JP01's expert witnesses concluded that BPA Staff's proposed use of a 25-hour value for heavy load hours was

[51] *Deen and Wellenius*, BP-18-E-JP01-02 at 3-10.
[52] *Id*.
[53] *Id*. at 10.
[54] *Id*. at 10-13; *Deen & Wellenius*, BP-18-E-JP01-01 at 19-20.

conservative[55] and well within other cost-based benchmarks.[56] JP01's witnesses also presented evidence that other transmission providers (including, coincidentally, certain members of JP03) have established tariff rates for service on the southern portions of California Oregon Intertie facilities at levels similar to BPA Staff's proposed hourly rate on BPA's Southern Intertie.[57] Finally, JP01 witnesses presented independent analysis that BPA Staff's rate proposal mitigates the potential for unintended adverse consequences, concerns about under-utilization of the Southern Intertie, stable revenue recovery, or the availability of other solutions for addressing seams issues on the Southern Intertie.[58] Although the specific evidence presented by BPA Staff and JP01 in this proceeding is discussed in greater detail below, it is clear that ample objective evidence supports BPA Staff's rate proposal.

B. Southern Intertie Queue Data Supports BPA's Concern about Cost Recovery

Both BPA Staff and JP01 presented substantial evidence and analyses concerning the queue for LTF service and renewals on the Southern Intertie that reveal significant financial risks to BPA. First, the queue for new LTF service on the Southern Intertie is declining. That queue has varied over the years, reaching over 11,000 MW in 2009,[59] but has dropped recently from 6,228 MW in September 2014 to 1002 MW at the start of the BP-18 rate case.[60] The queue has declined further still: at the end of 2016 there remained only 812 MW of requests for new LTF service,[61] and between January 2017 and March 2017 the queue declined an additional 200 MW.[62]

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[55] *Deen and Wellenius*, BP-18-E-JP01-01 at 20-24.
[56] *Id*. at 24-25.
[57] *Id*.
[58] *Id*. at 25-29.
[59] *Linn et al*., BP-18-E-BPA-25 at 4.
[60] *Fredrickson et al*., BP-18-E-BPA-12 at 7. Even JP03 agrees that requests for LTF service have declined sharply since the BP-16 rate proceeding. *Holcomb et al.*, BP-18-E-JP03-01 at 18.
[61] *Deen and Wellenius*, BP-18-E-JP01-01 at 7.
[62] *Linn et al*., BP-18-E-BPA-25 at 5. For instance, in December 2016, Portland General Electric withdrew its only remaining request for original service (100 MW) and Cargill declined a LTF service offer of 50 MW. *Deen and Wellenius*, BP-18-E-JP01-01 at 8.

Second, customers are rejecting BPA's offers of LTF service. A queue customer is not obligated to accept an offer of LTF service and is free to decline BPA's offer when made. Indeed, 460 MW was removed from the queue during the BP-16 rate period because customers rejected BPA's offers of service.[63] On the DC Intertie, there are five requests in the queue, though two are associated with customers that have recently rejected offers of service on the AC Intertie.[64] This past behavior of customers in the queue makes it evident that BPA's actual ability to sell LTF service may be well below the amount of requests in the queue, which itself is already greatly diminished.

Third, the upcoming BP-18 rate period will see numerous terminations of LTF service unless those customers renew. Specifically, 2,801 MW of LTF service (out of a total of 5,715 MW of BPA's North-to-South capacity) will terminate by the end of the BP-18 rate period unless customers decide to renew service.[65] But, BPA's exposure is even greater because a transmission customer must inform BPA of its intent to renew at least one year prior to the date of termination. With this consideration, the quantity of LTF transmission reservations that either expire or face renewal during the BP-18 rate period is 3,158 MW, more than half of the Southern Intertie capacity.[66]

BPA Staff have compelling grounds to link the decline in the Southern Intertie queue to the erosion of value of LTF service, contrary to JP03's assertions.[67] As described above, BPA Staff held an extensive process evaluating various alternatives and remedies for the seams issues

[63] *Fredrickson et al.*, BP-18-E-BPA-12 at 8. For example, Cargill has one other pending request, and if declined, the queue on the AC Intertie would consist only of a request from Avangrid, which also declined service the last time it was offered. *Deen and Wellenius*, BP-18-E-JP01-01 at 8; *Fredrickson et al.*, BP-18-E-BPA-25 at 7 (noting that the AC Intertie presently has two requests in the queue, both of which were submitted by customers that recently rejected offers of service).
[64] *Linn et al.*, BP-18-E-BPA-25 at 7.
[65] *Id*. at 14-15.
[66] *Deen and Wellenius*, BP-18-E-JP01-01 at 9.
[67] *Holcomb et al.*, BP-18-E-JP03-01 at 18.

between BPA and CAISO. When BPA Staff proposed to revise the Southern Intertie hourly rates, they did so in the context of the agency's consultation process and comments received. This context and background, as summarized in BPA Staff's rebuttal testimony,[68] sufficiently ties the explicit customer concerns about the erosion of value of LTF service to the decreased appetite for this service, reflected in the diminishing queue for LTF service. There is no further need to query every customer as to why it withdrew a particular request for LTF service from the queue, declined a specific offer of LTF service when provided, or renewed (or did not renew) expiring service since this would be duplicative to the agency's process.[69] The Administrator needs no further study or documentation to adopt BPA Staff's proposal.

The renewal rate for LTF service on the Southern Intertie has historically been high, and even reached 100 percent during FY 2016, as highlighted by JP03.[70] However, this single data point should provide no comfort for two reasons. First, by examining a longer time period, FY 2011-2016, the historical renewal rate is less than 100 percent.[71] The small quantity of requests for new service creates a risk of under-recovery even if renewal rates are only slightly below 100 percent. And second, customers renewing LTF service in FY 2016 may well have been informed by the agency's commitments in the BP-16 Final ROD (issued on July 23, 2015) to holding a process to address the erosion of value issue, and by staff's indications in that process that it would propose an increase in the hourly rate.[72]

BPA is facing considerable uncertainty as to whether it will recover the costs of the Southern Intertie segment. In contrast to prior rate cases, the queue for new LTF service now

[68] *Linn et al*., BP-18-E-BPA-25 at 4-6, 8-9, 14
[69] *Holcomb et al*., BP-18-E-JP03-01 at 18 (asserting that BPA does not know the reasons for the decline in the net size of the queue).
[70] *Linn et al*., BP-18-E-BPA-25 at 10.
[71] *Deen and Wellenius*, BP-18-E-JP01-02 at 8.
[72] BP-16 ROD at 112.

offers virtually no buffer should LTF customers not renew at very high levels, especially as BPA is facing possible renewals of nearly half of the Southern Intertie capacity during the upcoming rate period.[73] Even a few non-renewals could result in unsubscribed capacity on the Southern Intertie and a corresponding drop in the revenues.[74] That revenue risk is causally linked to customer concerns about the erosion of value of LTF service. To ignore the substantial evidence presented by BPA Staff and JP01 would perpetuate the outdated low hourly rate on the Southern Intertie and make unrealistic assumptions in setting rates.[75]

In contrast, JP03 contends that BPA should wait and see, suggesting "a tailored solution triggered by a real undersubscription for long-term service…."[76] But, delaying action would not be consistent with setting the lowest possible rates consistent with sound business principles when BPA is confronting an objective threat to recovery of its Southern Intertie costs.[77] In *Golden NW Aluminum, Inc. v. Bonneville Power Admin.,* 501 F.3d 1037, 1052 (9th Cir. 2007), the court faulted BPA for basing rates on outdated assumptions. Here too, for BPA to continue assuming that customers will seek LTF service on the Southern Intertie at historical levels would be to make an assumption contradictory to the evidence presented. BPA Staff agree that such a determination would be contrary to acting with sound business principles and using a "business-orientated philosophy."[78]

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[73] *Deen and Wellenius*, BP-18-E-JP01-02 at 6, 9 (stating that for the Southern Intertie to remain fully subscribed the renewal rate would need to be 100 percent on the DC Intertie and 92 percent on the AC Intertie).
[74] *Id*. at 6.
[75] *See Golden Nw. Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037, 1052 (9th Cir. 2007)(finding that BPA's unreasonable assumptions about its ability to recover fish and wildlife costs when faced with contradictory, unrebutted evidence were improper).
[76] *Holcomb et al*., BP-18-E-JP03-01 at 91.
[77] BPA must set rates to recover its costs, in accordance with sound business principles. 16 U.S.C. § 839e(a)(1). *See also* BP-16 ROD at 9 (stating that ignoring actual financial conditions in the year when rates are set is not a sound business practice).
[78] *Pub. Power Council v. Bonneville Power Admin.*, 442 F.3d 1204 (9th Cir. 2006); *Pac. Nw. Generating Co-op. v. Bonneville Power Admin.*, 596 F.3d 1065, 1074 (9th Cir. 2010) (holding that voluntarily providing a $32 monetary benefit to certain customers would not be in accordance with the agency acting in a manner "consistent with sound

C. Staff's Proposal Is Not a Deviation from Cost-Based Ratemaking

BPA Staff's proposal includes a simple change to the formula used to set the hourly rate on the Southern Intertie: it replaces the outdated assumption of 80 traditional heavy load hours with 25 hours, a number determined by BPA Staff's analysis of the evolving demand patterns in California.[79] BPA Staff's proposal does not contemplate setting the number of heavy load hours based on a forecast of usage or hourly reservations, again contrary to assertions by JP03.[80]

The substitution of 25 hours for 80 hours in the hourly rate calculation does not represent a shift from the long-established cost-based ratemaking used by BPA, as JP03 claims.[81] To clarify, BPA Staff and stakeholders presented concerns and analysis about the erosion of value of LTF service as a motivation for re-examining the Southern Intertie hourly rates. The *motivation* for addressing the hourly rate is separate and apart from the rate methodology used to set the rate, which has remained constant and unchanged from the BP-16 rate period and prior rate periods.[82] Indeed, for JP03 to attack the Southern Intertie rate calculation with the 25 heavy load hour divisor is to attack that same calculation using the 80 hour divisor. But, JP03 has provided no evidence that the rate formula itself—which is the same general formula used by JP03's members—falls short of allocating costs on an equitable basis to the hourly users of the Southern Intertie or that by changing the divisor BPA has divorced the calculation from the underlying costs of the Southern Intertie.[83]

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business principles."). *Linn et al.,* BP-18-E-BPA-25 at 10 ("We do not believe that waiting until cost recovery issues materialize is the most prudent course of action.").

[79] The formula: $\frac{\frac{\$14.98}{\text{kW}}\text{ (annual cost allocation)}}{\text{(8,760 hrs (average \# of hours in FY18,19))}}\left(\frac{168}{\mathbf{25}}\right) = 11.49\,\frac{\text{mills}}{\text{kW}}$

The 25 hours (in emphasis) replaces the previously used value of 80 hours.

[80] *Linn et al*., BP-18-E-BPA-25 at 15-16; *Deen and Wellenius*, BP-18-E-JP01-02 at 11-13.

[81] *Holcomb et al*., BP-18-E-JP03-01 at 33-45.

[82] *Deen and Wellenius*, BP-18-E-JP01-02 at 11-13.

[83] *Linn et al*., BP-18-E-BPA-25 at 37.

D. <u>BPA Staff's Proposal Is Conservative</u>

Besides changes in the queue for new LTF service, the current trends in California generation suggest that the net load shape will continue to change. The reduction in net load during the mid-days hours in California has moved further and faster than expected, and as the mid-day depression in net load becomes deeper and affects more hours, the number of hours in which there is high demand for energy imports into CAISO will continue to decline.[84] The changing shape of the CAISO net load, commonly referred to as the "duck curve," is largely driven by additions of utility-scale and behind-the-meter solar generation in California. Utility-scale solar generation is approximately 9,000 MW at present, but it is expected to increase by another 4,000 – 5,000 MW by 2020.[85] Behind-the-meter solar generation also is expected to increase by approximately 4,000 MW by 2020.[86] The addition of this solar generation likely means that BPA Staff's finding that there are currently 25 high-value hours per week may prove to overstate the actual number of high-value hours in the future. Not only do these forecasts show that BPA Staff's proposal is conservative, but they also indicate the Administrator should act now to address circumstances affecting the desirability of LTF service on the Southern Intertie.[87]

E. <u>Certain Uses of the LTF Capacity on the Southern Intertie Do Not Obviate the Need to Change the Hourly Rate</u>

JP03 has claimed that certain potential uses of firm transmission service on the Southern Intertie demonstrate that customers continue to have an incentive to purchase LTF service.[88] JP03

[84] *Deen and Wellenius*, BP-18-E-JP01-01 at 21.
[85] *Id*.
[86] *Id*. at 21-22.
[87] BPA Staff's proposal also made a simplifying and conservative assumption that the 25 high-value hours occur each and every week of the year. However, the patterns of hourly transmission reservations can vary substantially between weeks, given that market conditions are highly variable throughout the year; thus in a less conservative approach BPA Staff's proposal could have addressed the weekly variability as well. *Deen and Wellenius*, BP-18-E-JP01-01 at 22-23.
[88] *Holcomb et al.*, BP-18-E-JP03-01 at 46-47.

points to the need for LTF service in order to obtain dynamic scheduling capabilities, arguing this functionality is valuable and necessary for delivery of certain categories of renewable resources under California's Renewable Portfolio Standards ("RPS"). JP03 also alludes to the role of LTF service in connection with the evolving Energy Imbalance Market ("EIM") as well as for sales of certain Ancillary Services to CAISO. But JP03 fails to disclose, much less address, the fact that the quantity of LTF service used in this manner is extremely limited. For instance, the DC Intertie does not currently support dynamic scheduling, or even 15-minute schedules. And as the record reflects, BPA's share of the dynamic transfer capability on the AC Intertie is only approximately 225 MW,[89] representing less than 5 percent of BPA's total north-to-south Southern Intertie capacity. Thus even assuming such uses confer ongoing value, JP03's argument simply does not apply to the vast majority of BPA's Southern Intertie capacity, and hence does not mitigate the concerns set out by BPA Staff regarding BPA's ability to recover the costs of the Southern Intertie segment through continued high levels of sales of LTF service.

F. BPA Staff and JP01 Rebutted Potential Impacts Identified by JP03

BPA Staff's proposal is simple in both theory and execution and offers a targeted solution to a specific problem. JP03 broadly asserts that implementation of Staff's proposal will cause an increase in costs to California entities, the potential collapse of the energy markets at COB and NOB with a corresponding drop in energy prices at Mid-C. JP03 also asserts that the magnitude of the price increase at COB and NOB will be approximately $8/MWh, roughly the difference between the BP-16 hourly rate and the proposed hourly rate for the BP-18 rate period.[90] These concerns were addressed and rebutted by BPA Staff and JP01, as reviewed below. Regardless, BPA must be first and foremost concerned with meeting its statutory requirements, such as setting

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[89] *Linn et al.*, BP-18-E-BPA-25 at 11.
[90] *Holcomb et al.*, BP-18-E-JP03-01 at 62.

rates to recover its costs, and not with reviewing allegations of impacts to California entities that may or may not occur as a result of setting appropriate cost-based rates.[91]

First, BPA Staff's analysis of the alleged $8/MWh increase in power prices shows that such predictions are unrealistic. Buyers in California have other options to procure energy, as JP03 acknowledges, requiring a seller using Southern Intertie capacity to offer delivered energy at competitive market prices.[92] In addition, BPA Staff's analysis showed JP03's theory to be inconsistent with observed power pricing. The difference in pricing between Mid-C (the major trading hub in the Northwest) and COB did not track BPA's rate for hourly service between those two points, as JP03's theory would suggest.[93] Instead, Staff found that the pricing differential between COB and Mid-C is volatile and that the hourly rate does not necessarily correlate to the difference in price. Further, BPA Staff examined resale prices of LTF transmission service, finding that the resale value is less than the posted hourly rate, which means that LTF customers will not necessarily be able to increase their re-sale price by the proposed increase in the hourly rate.[94] In sum, JP03's predictions of dramatic price increases at COB are unrealistic and without support.[95]

Second, JP03's concerns about evaporating liquidity at COB and NOB are misplaced.[96] Transactions actually scheduled using original hourly transmission service represent approximately 2 percent of the energy delivered to California. The vast majority (roughly 98 percent) of energy delivered to California is done so using Southern Intertie transmission services

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[91] 16 U.S.C. § 839e(a)(1).
[92] *Linn et al*., BP-18-E-BPA-25 at 26-28.
[93] *Id*. at 28.
[94] *Id*. at 28-29.
[95] BPA Staff also states that JP03's claims of higher prices at COB and NOB are not supported by analysis but are simply based on personal experience. *See Linn et al*., BP-18-E-BPA-25 at 27, 31.
[96] *Holcomb et al.*, BP-18-E-JP03-02-CC01 at 22.

other than original hourly service.[97] Thus, to the extent that the increased hourly rate diminishes energy transactions at COB and NOB that rely on hourly service, this impact will be minimal. Conversely, fully subscribed LTF service minimizes transactions costs or "hurdle rates," which in turn incentivizes the LTF customer either to utilize or to resell unneeded capacity to other users. It is full subscription of the Southern Intertie under LTF service—and not the rate for hourly service—that supports liquidity at COB and NOB.[98]

Likewise, the potential impact to SMUD is over-stated and unsupported. SMUD alleges (as a member of JP03) potential impacts of \$1.3 million to \$4.4 million annually.[99] But, JP03's analysis includes assumptions that are unrealistic and without basis, such as the \$8/MWh increase in energy prices at COB and NOB discussed above. Further, JP03 does not even know how much, if any, of SMUD's 2016 hourly energy purchases were delivered using BPA's hourly transmission service, thus JP03 cannot claim that any—let alone all—of its energy purchases will incur the higher hourly rate.[100] Similarly, JP03 witnesses aver that staff from Energy and Environmental Economics ("E3") provided certain numbers, but by JP03's own explanation, these numbers are based on the erroneous assumptions (dictated by JP03's experts) that all of SMUD's energy purchasers would be \$8/MWh more expensive and that hourly markets at COB would either suffer reduced liquidity or collapse altogether. These core assertions have been fully rebutted by BPA Staff and JP01 testimony. The E3 numbers—based on faulty assumptions—can produce only faulty conclusions and should be afforded no weight.

Even if SMUD's purchase costs at COB were to increase, this impact must be put in the context of the impact to BPA's customers from reduced sales of LTF service, and the attendant

[97] *Linn et al.*, BP-18-E-BPA-25 at 29-30.
[98] *Id*. at 30.
[99] *Holcomb et al.*, BP-18-E-JP03-01 at 12-13; *Holcomb et al.*, BP-18-E-JP03-02-CC01 at 25.
[100] *Deen and Wellenius*, BP-18-E-JP01-02 at 15-16.

risk of failure to recover the costs of the Southern Intertie segment. Just 100 MW of unsubscribed capacity (on facilities with 5,715 MW of North-to-South capacity) would result in BPA losing LTF sales revenues of approximately $1.5 million per year (i.e., an amount comparable to SMUD's alleged impact).[101] And, with a limited queue for new LTF service and 2,801 megawatts up for renewal during the BP-18 rate period, BPA's risk of under-subscription of LTF service and attendant revenue deficit is clearly very significant.

Finally, in the unlikely event that adverse unintended consequences arise, in the near-term BPA retains the ability to discount the hourly rate at its discretion. In the longer-term, BPA sets rates every two years and could re-evaluate the hourly rate in the BP-20 rate proceeding, if necessary.

V. BPA STAFF'S PROPOSAL DIFFERS FROM THE PROPOSAL ADDRESSED IN THE BP-16 RATE CASE

JP03 argues that because the Administrator rejected a proposal in the BP-16 rate proceeding to change BPA's hourly rate on the Southern Intertie, he should do so again here. But, BPA Staff's rate proposal in this proceeding differs materially from the customers' BP-16 proposal. Specifically, BPA Staff's current proposal is based on a well-documented, uncontroverted change in the high-value hours in California, and not on historical usage of hourly service on the Southern Intertie, as in the BP-16 rate proceeding. As explained above, the peak demand hours on the Southern Intertie now total only 5 hours per day, and BPA Staff's proposed hourly rate "is simply acknowledging the reality of a five-hour-per-day-peak in California."[102] It

[101] If the entirety of the 2,801 MW up for renewal during the BP-18 rate period is not renewed, BPA would forgo over $40 million in revenues (derived by multiplying the base rate of $14,760 per MW-year by 2,801 MW). *See Linn et al.*, BP-18-E-BPA-25 at 15.
[102] *Id.* at 16.

is immaterial that the Administrator rejected a different Southern Intertie rate proposal advanced under different circumstances in BP-16.

In addition, BPA Staff's proposal will not result in the "vicious cycle" of increasing hourly rates if the volume of hourly sales declines. BPA Staff's proposal revises the 80 traditional heavy load hours to the 25 high-value hours based on the changes in California's net load shape; BPA Staff's proposal does not rely on usage patterns or on anticipating the numbers of hours the average customer will use hourly service in a given week, as proposed in the BP-16 rate proceeding.[103] Thus, the concern about the hourly rate spiraling upward is misplaced.

JP03 also argues that there has been no material change in the agency's risk of under-recovery of Southern Intertie embedded costs since the BP-16 rate proceeding. When assessing the risk of under-recovery for the BP-16 rate period, BPA Staff and the Administrator relied on the depth of BPA's Southern Intertie queue relative to the MW up for renewal.[104] The changes in the size of BPA's queue were discussed in great detail above. In contrast to BP-16, in the BP-18 rate period, the agency is confronted with 2,801 MW of LTF service (representing over $40 million in annual revenues) that are up for renewal, a queue that is significantly smaller than that, and a growing number of queue customers who have rejected LTF service offered in the last year.[105] "All of this demonstrates the additional risk of underrecovery in BP-18 as compared to BP-16,"[106] a risk that the Administrator should not ignore.

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[103] *Id*. at 15-16; *Deen and Wellenius*, BP-18-E-JP01-02 at 20-21.
[104] *Linn et al.*, BP-18-E-BPA-25 at 14; BP-16 ROD at 111.
[105] *Linn et al.*, BP-18-E-BPA-25 at 14-15; infra, fn. 101; BP-18-E-JP01-03 at 2 (Response to Data Request PP-BPA-26-62).
[106] *Linn et al.*, BP-18-E-BPA-25 at 15.

VI. THE ADMINISTRATOR SHOULD UPHOLD THE HEARING OFFICER'S DENIAL OF JP03'S MOTION TO COMPEL

On March 24, 2017, the Administrator issued an order on JP03's petition for interlocutory appeal of the Hearing Officer's denial of JP03's motion to compel.[107] In that order, the Administrator stated that parties may address the issues in their Initial Briefs. As discussed in detail in JP01's answer to JP03's petition for interlocutory appeal and briefly reviewed here, the Administrator should deny the petition and uphold the Hearing Officer's order.

JP01 provided direct testimony supporting BPA Staff's proposal to revise the Southern Intertie hourly rate. JP01's direct testimony provided an analysis of publicly available information and concluded that (1) BPA should take prompt action in this rate case as an analysis of BPA's queue for LTF service on the Southern Intertie showed weakness in the demand for such service, which could result in possible under-recovery; (2) BPA Staff's proposed hourly rate will provide a strong incentive for BPA transmission customers to continue to choose LTF service over hourly service; (3) BPA Staff's proposal is consistent with BPA's long-standing rate design and rate methodologies; and (4) BPA Staff's proposal does not raise concerns about unintended consequences.[108]

On the basis of JP01's testimony, JP03 sought to compel Powerex to provide a broad array of highly-sensitive commercial documents, including profitability analyses, internal documents and communications, and related documents concerning Powerex's commercial decision-making.[109] The JP01 witnesses did not open the door to JP03's invasive data requests as the JP01

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[107] BP-18-A-01.
[108] *Deen and Wellenius*, BP-18-E-JP01-01 at 1-2; BP-18-M-JP01-03 at 1-3; BP-18-M-JP01-01. For additional context and arguments, please refer to BP-18-M-JP01-01, BP-18-M-JP01-02, and BP-18-M-JP01-03.
[109] BP-18-M-JP01-03 at 1-3. To clarify, the JP01 witnesses did make representations about the identities of Powerex and PPC, but these basic and preliminary statements (e.g., "Powerex markets power exported from the

direct testimony did not make representations about members of JP01 but analyzed only publicly available information. Thus, demands for Powerex's highly-sensitive commercial documents are outside the scope of JP01's testimony and permissible discovery. JP01 also objected to (1) providing publicly available information to which JP03 itself had access; (2) performing analyses of publicly available information that JP03 also could perform itself; (3) answering hypothetical and conjectural questions;[110] (4) providing confidential, commercially-sensitive documents to a potential counter-party;[111] and (5) providing privileged documents and communications.[112] The Hearing Officer correctly upheld JP01's objections.

JP03 has had a full opportunity to participate and present evidence in this rate proceeding, as evidenced by its voluminous direct and rebuttal testimonies, hundreds of data requests, and cross examination of the BPA and JP01 witnesses. The Administrator should uphold the Hearing Officer's denial of JP03's motion to compel.

VII. CONCLUSION: THE ADMINISTRATOR SHOULD ADOPT BPA STAFF'S PROPOSAL

BPA Staff and JP01 have presented clear, convincing and substantial evidence that the value of LTF transmission service on the Southern Intertie has eroded, that the erosion of value is reducing demand for LTF service, and that reduced demand for LTF service could jeopardize BPA's ability to recover the Southern Intertie segment costs. Moreover, BPA Staff and JP01 have demonstrated that updating the rate formula with the proper number of high-value hours is an

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surplus capability of the predominantly hydropower generation facilities of its parent British Columbia Hydro and Power Authority (BC Hydro).") did not pertain to the Southern Intertie.

[110] The Hearing Officer stated in responses to a JP03 data request that posed a question about future renewal decisions, "[a] party may not create testimony of another party for the purposes of seeking information not raised by the requested party's testimony itself." BP-18-HOO-21 at 11.

[111] The potential sanctions, such as striking JP03 documents in this rate case, that could be imposed on JP03 by the Hearing Officer for disclosing highly-sensitive Powerex documents pale in comparison to the long-term competitive harm that Powerex might suffer from such disclosure.

[112] BP-18-M-JP01-01 at 12-41.

effective remedy to incentivize customers to continue to invest in LTF service, ensuring BPA continues to recover the cost of the Southern Intertie segment through its rates and without significant adverse or unintended consequences. This rate proposal is supported by not just BPA Staff, but also by a broad coalition of BPA's customers, with the only opposition coming from a group of three California-based entities that seek to preserve the inequitable transfer of benefits that arise from the status quo. The proposed change to the Southern Intertie hourly rate is within the Administrator's authority and discretion to implement, and JP01 urges the Administrator to act now.

Respectfully submitted,

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May 2, 2017

LIST OF JOINT PARTY 1 EXHIBITS

Exhibit No.	Exhibit Name	Date Filed	Status
BP-18-E-JP01-01	Direct Testimony of Joint Party 01	January 31, 2017	Admitted
BP-18-E-JP01-02	Rebuttal Testimony of Joint Party 01	March 14, 2017	Admitted
BP-18-Q-PP-03	Qualification Statement of Michael Deen	January 23, 2017	Admitted
BP-18-Q-PX-02	Qualification Statement of P. Kevin Wellenius	January 31, 2017	Admitted
BP-18-E-JP01-03	Data Requests and Responses Admitted into the Record	April 24, 2017	Admitted

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing document on Bonneville Power Administration's Office of General Counsel, the Hearing Clerk, and all litigants in this proceeding by uploading the document on the 2018 Joint Power and Transmission Rate Adjustment Proceeding (BP-18) secure website, pursuant to BP-18-HOO-02 and BP-18-HOO-05.

Dated this 2nd day of May, 2017 at Seattle, Washington.

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