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	**)**	

REBUTTAL TESTIMONY OF:

Public Power Council
Northwest Requirements Utilities
Pacific Northwest Generating Cooperative
Idaho Falls Power
Snohomish County Public Utility District No. 1
Eugene Water & Electric Board
Cowlitz County Public Utility District No. 1

as

JOINT PARTY 5

SUBJECT:
Financial Reserves Policy

WITNESSES:
Michael Deen
Megan Stratman
Scott Russell
Greg Mendonca
Kevin O'Meara
Christopher Weber

March 14, 2017

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SECTION 1: INTRODUCTION

Q: Please state your name and qualifications.

A: My name is Michael Deen. My qualifications are shown at BP-18-Q-PP-03.

A: My name is Megan Stratman. My qualifications are shown at BP-18-Q-NR-01.

A: My name is Scott Russell. My qualifications are shown at BP-18-Q-PN-02.

A: My name is Greg Mendonca. My qualifications are shown at BP-18-Q-PN-01.

A: My name is Kevin O'Meara. My qualifications are shown at BP-18-Q-PP-01.

A: My name is Chris Weber. My qualifications are shown at BP-18-Q-PP-04.

Q: What is the purpose of your testimony?

A: The purpose of our rebuttal testimony is to address certain arguments and proposals advanced in the direct testimony of Joint Party 2 ("JP02"), Powerex, and M-S-R Public Power Agency ("MSR") regarding BPA staff's proposed financial reserves policy.

Q: Please summarize your conclusions.

A: The various concerns raised by these parties regarding equity between business lines, the purpose and implementation of the Treasury Payment Probability (TPP) standard, and concerns about a "phase-in" of a financial reserves policy that considers rate impacts are unwarranted. We also oppose the proposal advanced by MSR for "lending" of reserves between business lines and Powerex's proposal for distribution of certain reserves above what are needed to meet the TPP standard.

Our overarching conclusion is that the financial reserves policy proposal advanced in the JP05 direct testimony is the best approach available to the Administrator.[1] Our proposal is comprehensive and addresses the core issues related to

[1] *See* Deen et al., BP-18-E-JP05-01 at 17-26, lines 13-15; Exhibit A at 1-5.

credit rating support raised by BPA staff while also maximizing the collaborative efforts of BPA and its customers to provide the most competitive rates possible in both the short and long term.

Q: How is your testimony organized?

A: First, we respond to the arguments put forth by JP02, MSR, and Powerex regarding equity between business lines. We explain that the amount of financial reserves attributed to Power and Transmission has varied over the years, the accumulation of financial reserves for Transmission was a result of several settled transmission rate proceedings where transmission customers agreed to the transmission rates they paid, and that JP02, MSR, and Powerex fail to connect the benefits of a financial reserves policy to the costs of carrying such reserves. Second, we explain how JP02, MSR, and Powerex misconstrue the purpose of the TPP standard, which is to support BPA's liquidity, and is separate and distinct from the purpose of a financial reserves policy. Third, we reject the arguments made by JP02 and MSR regarding BPA staff's proposed phase in for Power but point out that the JP05 proposal eliminates this issue by not including a phase in for either business line. Finally, we explain that MSR's proposal to lend reserves between business lines is unfounded given how BPA manages its finances.

SECTION 2: PURPORTED INEQUITY ISSUES

Q: What do JP02, MSR and Powerex assert with respect to equity between the two business lines under BPA staff's proposal?

A: JP02, MSR and Powerex variously argue that there is inequity between business lines in the relative distribution of financial reserves between Power and Transmission, and further that BPA staff's proposed financial reserves policy does not meet BPA staff's stated goal to "maintain equity between business lines."[2]

Q: Why do JP02, MSR and Powerex claim that there is inequity between the two business lines, and why do they argue that BPA staff's proposed financial reserves policy does not adequately address such inequity?

A: As described in more detail below, the three parties cite the relative amount of financial reserves attributed to Power versus Transmission, both in recent history and the expected values at the end of FY 2018 and FY 2019. They conclude that because relatively more financial reserves have been attributed to Transmission than to Power both in recent years and on a projected basis for BP-18, this constitutes inequity between the two business lines, thus failing to meet one of BPA staff's stated objectives to "maintain equity between business lines."

Q: How do you respond to these assertions?

A: These parties do not apply appropriate metrics for determining whether equity is maintained between the business lines. As discussed in greater detail below, JP02, MSR and Powerex view "equity" simply as relative numerical equality in the days' cash on hand held by the Power and the Transmission business lines.

As described in our direct testimony, "equity" should be based on whether costs follow benefits under a proposed financial reserves policy.[3] Under BPA staff's proposal, this was not the case. However, under the JP05 proposal, equity is achieved between the two business lines by aligning costs and benefits. Also, our proposal further addresses equity issues by giving the best chance that neither business line would have to raise rates

[2] Harris et al., BP-18-E-BPA-17 at 24, line 3.
[3] *See* Deen et al., BP-18-E-JP05 at 21through 22, lines 1-5; 23, lines 10-23 through 24, lines 1-10.

in order to support BPA's credit rating. Because JP02, Powerex and MSR focus exclusively on whether the financial reserves currently held by each business line are "proportionate" to the operating expenses of the business line, they ignore the objective of having a long-term policy that is equitable.

Q: Please further describe the various assertions regarding historical and future inequity in the level of reserves between BPA's business lines.

A: JP02 states that "[o]ver the past ten years, Power services has experienced great volatility in the accumulation of its financial reserves"[4] while "Transmission financial reserves have been far more stable and robust."[5] JP02 cites the expected values for net reserves at the end of FY 2018 and FY 2019, where reserves attributed to Transmission are projected to be larger than the amount of reserves attributed to Power, and concludes that "BPA's proposal ensures that Transmission rates will continue to bear an inequitable share of BPA's financial reserves burden for the near future."[6] As such, JP02 argues that BPA's proposed financial reserves policy will not meet BPA's objective to provide equity between the two business lines.[7]

Similarly, MSR and Powerex also cite the expected values of Power's and Transmission's reserves at the end of FY 2018 and FY 2019 in their discussions of the purported inequities between the two business lines.[8] Powerex asserts that Transmission is "over-contributing" in support of BPA's credit rating because Transmission contributes roughly three-quarters of BPA's overall financial reserves.[9] Powerex claims this is "out

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[4] Wrigley et al., BP-18-E-JP02-01 at 7, lines 11-12.
[5] *Id.* at 7, line 16.
[6] *Id.* at 7, lines 3-10.
[7] *Id.* at 6, lines 21-22.
[8] Opatrny, BP-18-E-PX-01 at 3-4, lines 19-6; Arthur, BP-18-E-MS-12 at 24, lines 6-12.
[9] Opatrny, BP-18-E-PX-01 at 7, lines 5-6.

of line" with the Transmission revenue requirement of $1.06 billion per year as compared to BPA's total agency revenue requirement of $3.96 billion per year.[10]

Q: *Please summarize the arguments JP02, Powerex, and MSR make regarding the benefits associated with financial reserves.*

A: The three parties argue that the test of "equity" should consider only whether the financial reserves attributed to each business line are equal relative to each business line's operating expenses. JP02 asserts that BPA staff's proposed financial reserves policy will continue to "allow a disproportionately large share of the responsibility for maintaining the overall Agency financial reserves to be borne by the Transmission business line, which benefits the Power business line."[11]

MSR argues that Transmission cannot "repurpose its excess reserves to a better use" unless agency reserves reach their upper threshold.[12] MSR then compares each business line's relative days' cash on hand to the amount of agency reserves held at the end of FY 2016 and argues that in order for Transmission to be able to "make better use of its reserves," Power would need to more than double its current reserves.[13]

Powerex argues that the goal of "equity" should include "equitable contribution" where each business line makes a proportionate contribution to the agency's overall need for financial reserves.[14] Powerex says that to achieve an equitable allocation, the financial reserves policy should, "(1) provide some pathway to reduce Transmission's current

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[10] Opatrny, BP-18-E-PX-01 at 7, lines 8-12.
[11] Wrigley et al., BP-18-E-JP02-01 at 7, lines 1-3.
[12] Arthur, BP-18-E-MS-12 at 24, lines 4-6.
[13] *Id.* at 24, lines 6-15.
[14] Opatrny, BP-18-E-PX-01 at 13, lines 19-22.

inequitable over-contribution, and (2) provide a durable mechanism to avoid the recurrence of one business line from inequitably over-contributing in the future."[15]

Q: *How do you respond to these various arguments regarding equity between business lines?*

A: First, the relative amount of financial reserves attributed to each business line has changed over the years. It is true that in recent years, more than half of the agency's reserves have been attributed to Transmission. However, 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.[16] Second, the arguments that an "inequity" exists in the distribution of reserves between Power and Transmission are based on the false premise that transmission customers are necessarily entitled to a distribution of financial reserves not strictly needed to meet the 95% TPP standard. In particular, the parties' arguments ignore the fact that transmission rates were settled from 1996 to 2013.[17] Instead of litigating transmission rates, revenues were adjusted as needed to ensure costs were covered pursuant to BPA's statutory obligations. BP-14 was the first rate case since 1996 where transmission rates were fully litigated, and the BP-14 Final Record of Decision spoke directly to the previous rate case settlements.

In the BP-14 Final ROD, the Administrator described that "[c]ustomers have paid rates that were set to achieve cost recovery, agreed to in settlement of every rate case

[15] Opatrny, BP-18-E-PX-01 at 13, line 22 through 14, line 3.
[16] BPA Financial Reserves Workshop #3 at 18 (June 15, 2016), available at: https://www.bpa.gov/Finance/FinancialPublicProcesses/AccesstoCapital/June%2015%20BPA%20Reserves%20Workshop%203.pdf.
[17] BP-14 Power and Transmission Rate Proceeding Administrator's Final Record of Decision ("BP-14 Final ROD), BP-14-A-03 at 141 (July 2013).

since 1996, and that have been approved by the Federal Energy Regulatory Commission."[18] The Administrator clarified that these settled transmission rates did not contain any mechanisms requiring that revenues in excess of costs be returned to customers. Perhaps most important to the issue at hand, the Administrator stated that parties have no right to any accumulation of reserves that may occur and "that any accumulation of reserves would be put to use for the long-term benefit of the system and, ultimately, ratepayers."[19]

This was reaffirmed in the BP-16 Administrator's Final Record of Decision: "customers during prior rate periods (1996 to 2013) have no right to the accumulation of reserves during those periods because the rates were set to achieve cost recovery and customers agreed to the rates in settlements."[20] Therefore, any assertion made by JP02, MSR or Powerex that Transmission has "over-contributed"[21] to the agency's amount of financial reserves or that Transmission bears "an inequitable share"[22] of the agency's financial reserves "burden" is inconsistent with the terms of the transmission rates settlements and the BP-14 and BP-16 Final RODs. Customers, including JP02 members, Powerex, and MSR, agreed to rates set to achieve cost recovery, and have "no right to the accumulation of reserves" from 1996 to 2013.[23] Indeed, Transmission reserves have noticeably declined since 2013. This decline is in large part by design as the agency deliberately put those funds to other uses. As an example, BPA is utilizing $15 million

[18] BP-14 Final ROD at 141.
[19] *Id.*
[20] BP-16 Power and Transmission Rate Proceeding Administrator's Final Record of Decision ("BP-16 Final ROD"), BP-16-A-02 at 91 (July 2015).
[21] Opatrny, BP-18-E-PX-01 at 7, lines 5-6.
[22] Wrigley et al., BP-18-E-JP02-01 at 7, lines 8-10.
[23] BP-16 Final ROD at 91.

per year of transmission reserves to fund capital projects in BP-18.[24] Transmission reserves are projected to decline even further during the upcoming rate period absent any additional action.

The foregoing background also negates JP02's assertion that excess reserves should be returned to customers via a rate reduction mechanism only.[25] In the JP05 counterproposal, we maintained the same Reserves Distribution Clause (RDC) construct as in BPA staff's initial proposal. To the extent reserves exceed the upper thresholds, "the Administrator shall consider the above-threshold financial reserves for investment in other high value business line specific purposes including, but not limited to, debt retirement, incremental capital investment, or rate reduction."[26] As described above, prior Records of Decision (RODs) are clear that any accumulation of reserves would be put to use for the long-term benefit of the system and, ultimately, ratepayers. The JP05 counterproposal complies with this policy direction while the JP02 proposal explicitly contradicts it.

Given that transmission customers are not entitled to refunds of reserves, particularly of amounts accumulated during settlement, there is no valid basis for claims that Transmission is somehow bearing an inequitable level of reserves. Further, holding some level of those reserves does not increase Transmission rates through time. In contrast, BPA's staff's proposal and the positions of JP02, Powerex, and MSR would require the agency to raise power rates or take other rate actions that otherwise would not have been necessary.

[24] Transmission Revenue Requirement Study, BP-18-E-BPA-09 at 15, lines 21-22.
[25] Wrigley et al., BP-18-E-JP02-01 at 13, lines 18-19.
[26] Deen et al., BP-18-E-JP05-01, Exhibit A at 2, Section 3.5.

Finally, and perhaps most importantly, JP02, Powerex and MSR neglect to link the benefits from a financial reserves policy to the costs of carrying such reserves. Because the primary benefit of BPA's proposed financial reserves policy is to support BPA's credit rating,[27] evaluation of whether a financial reserves policy maintains equity between business lines must look at the benefits of such policy. Our direct case speaks to this at length, but we summarize it here. Where the need to support BPA's credit rating is driving the development and implementation of a financial reserves policy, the primary benefit to the agency is lower interest expense due to a higher credit rating.[28] BPA is rated as one entity by the credit rating agencies, which is why JP05 proposed that both the upper and lower threshold checks first be made at the agency level. If the agency is above the lower threshold and below the upper threshold, no further action is taken.

If this is not the case, then the next step is to allocate the financial reserves thresholds to each business line based on how much each business line stands to benefit from BPA's creditworthiness. To do so, one must consider the capital expenditures of each business line. In the Initial Proposal, BPA staff state that a credit rating downgrade would increase BPA's borrowing costs on newly issued non-federal debt by roughly 50 basis points.[29] BPA staff say that for the planned amount of non-federal debt issuances over the next 10 years, a 50-basis-point interest rate increase could increase revenue requirement costs by a maximum $33 million attributed to Transmission Services and $22 million to Power Services.[30] Equitable treatment between business lines should be based on relative benefits. In this case, the benefit from avoiding a credit downgrade is

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[27] Deen et al., BP-18-E-JP05-01 at 7, lines 1-5.
[28] *Id.* at 7, lines 9-10.
[29] Harris et al., BP-18-E-BPA-17 at 17, lines 9-10.
[30] *Id.* at 17, lines 12-14.

lower interest expense. Therefore, determination of whether the financial reserves policy is equitable must be based on the relative benefit of each business line, and not simply the relative magnitude of reserves attributed to each business line compared to operating expenses. In order to better align costs and benefits, JP05 proposed a financial reserves policy that allocated responsibility for agency total reserves as the proportion of each business line's forecasted contribution to BPA's overall planned capital expenditures on a rolling 10-year basis.[31] This is the metric upon which BPA's objective to "maintain equity between business lines" should be evaluated. The JP05 proposal, as described in our direct case, meets that objective.

SECTION 3: PURPOSE AND IMPLEMENTATION OF THE TPP STANDARD

Q: What do JP02, Powerex, and MSR say with regard to the interaction between BPA's proposed financial reserves policy and its TPP standard?

A: In summary, these parties argue against using the Treasury Facility when determining whether Power Services meets or exceeds the 95 percent TPP standard when establishing Power's financial reserves target. JP02 argues that the Treasury Facility should not be used when calculating the TPP for either business line in establishing the financial reserves target for such business line.[32] JP02 says using some or all of the Treasury Facility when calculating the TPP for a business line means that the TPP test "does not provide a meaningful standard for purposes of determining the target level of financial reserves,"[33] in part because the rating agencies do not consider the Treasury Facility in their calculations of days' cash on hand.[34]

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[31] Deen et al., BP-18-E-JP05-01 at 18, lines 21-23.
[32] Wrigley et al., BP-18-E-JP02-01 at 9, lines 7-8.
[33] *Id.* at 9, lines 11-14.
[34] *Id.* at 9, lines 20-21.

MSR says that using a portion of the Treasury Facility when calculating the TPP for Power limits the TPP standard's "ability to control for a prudent level of Power Financial reserves."[35] MSR also says that because the "credit agencies do not view the emergency source of liquidity as support for BPA's credit rating," use of the Treasury Facility "to meet Power's TPP requirement as part of the reserves policy undermines the second objective for the policy."[36]

Powerex asserts that "BPA's reliance on the Treasury Facility, in lieu of financial reserves, is not supportable in the long-term, as demonstrated by the contemporaneous reliance on the Treasury Facility and declining reserves in recent years. This evidence indicates … that the status quo is not supportable."[37]

Q: How do you respond?

A: The mischaracterizations of JP02, Powerex, and MSR of the role of the TPP standard and its interaction with a financial reserves policy underscore why JP05 proposed that BPA adopt a financial reserves policy that is independent and supplemental to the TPP standard.[38] BPA has been very clear that it addresses its need for liquidity by meeting or exceeding the 95 percent TPP standard.[39] Nonetheless, parties mischaracterize how BPA ensures it meets its liquidity needs. For example, 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."[40] Similarly, Powerex argues that "Transmission is carrying the burden

[35] Arthur, BP-18-E-MS-12 at 21, lines 3-11.
[36] *Id.* at 22, lines 7-11.
[37] Opatrny, BP-18-E-PX-01 at 5, lines 17-21.
[38] Deen et al., BP-18-E-JP05-01 at 20, line 20.
[39] Response to Data Request PP-BPA-26-16 (attached as Exhibit A).
[40] Arthur, BP-18-E-MS-12 at 25, lines 9-11.

of internal liquidity" because the amount of financial reserves attributed to Transmission happens to exceed the amount attributed to Power in recent years and projected for BP-18.[41] Powerex also links revenue volatility to credit risk.[42]

These arguments are incorrect. Revenue volatility is addressed solely via the TPP standard. Because both business lines meet the TPP standard on an individual basis, neither is bearing an undue share of BPA's liquidity needs. Also, the use of the Treasury Facility for TPP calculations is not the cause of the decline in Power financial reserves. Since 2008, declines in reserves attributable to Power have been due to adverse financial results, driven largely by low net secondary revenues relative to rate case forecasts. Indeed, reserves attributable to Power more than doubled from the end of fiscal year 2013 to the end of fiscal year 2015, well after the first instance of including the Treasury Facility in Power's TPP calculations in the WP-10 rate proceeding.

As we discussed in detail in our direct testimony, BPA relies on its TPP standard to ensure it maintains adequate liquidity over the rate period.[43] 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. The myriad of interpretations in the parties' direct cases highlight this potential for confusion.

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[41] Opatrny, BP-18-E-PX-01 at 16, line 5.
[42] *Id.* at 7, lines 15-17.
[43] Deen et al., BP-18-E-JP05-01 at 4, lines 6-9.

BPA should continue to use the Treasury Facility in its TPP calculations as it has done historically. Further, it is our understanding that using a portion of the Treasury Facility when evaluating whether Transmission meets or exceeds the 95 percent TPP standard would not reduce transmission rates in this proceeding and would not have reduced Transmission rates in prior proceedings. However, disallowing any use of the Treasury Facility when determining whether Power meets or exceeds the 95 percent TPP standard would necessitate raising rates or substantially increasing the probability of a Cost Recovery Adjustment Clause (CRAC) while failing to accurately account for all the liquidity tools available to BPA (in this case, the existence of the $750 million Treasury Facility). Again, the primary purpose of BPA staff's proposed financial reserves policy is to support BPA's credit rating. The final policy should be kept separate and distinct from the mechanism BPA has successfully used since 1993 to ensure liquidity.

Q: What is your recommendation regarding Powerex's proposal to redistribute some level of reserves above the amounts needed to meet the 95% TPP standard?

A: Based on the purpose and implementation of the TPP standard, as well as our analysis of the equity issues involved between business lines, Powerex's proposal should be rejected. Any redistribution of financial reserves should be handled through the mechanisms proposed in our direct testimony.

SECTION 4: ARGUMENTS REGARDING BPA STAFF'S PROPOSED PHASE-IN

Q: What do JP02 and MSR contend with respect to BPA staff's proposed phase-in of its financial reserves proposal for Power?

A: JP02 states that "[t]he proposed ten-year phase-in for BPA's Power business line of the minimum reserves threshold is too long and uncertain. There is no assurance that the minimum reserves threshold for power [proposed by BPA staff] will be achieved."[44] Similarly, MSR states that "proposed Phase-In elements for Power avoid rate shock, but undermine the Policy Goals of maintaining the Agency's credit rating, ensuring liquidity, maintaining equity, setting lower and upper reserves thresholds, and ensuring Treasury repayment."[45]

Q: Do you agree with these assertions?

A: No. Consideration of cost and rate impacts must be a central factor for any proposed financial reserves policy. Maintaining 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.

Q: Do JP02 or MSR make a specific recommendation as to how BPA staff's proposal should be changed?

A: No. The JP02 and MSR testimony provides only vague complaints and no constructive recommendations. Conversely, the JP05 direct testimony provided a comprehensive proposal focused on identifying the costs and benefits of maintaining financial reserves for credit support purposes. Our proposal obviates the phase-in concerns raised by JP02 and MSR because it does not require a phase-in period for either business line.

SECTION 5: "LENDING" OF RESERVES BETWEEN BUSINESS LINES

Q: What does MSR propose with respect to "lending" financial reserves between business lines?

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[44] Wrigley et al., BP-18-E-JP02-01 at 2, lines 16-19.
[45] Arthur, BP-18-E-MS-12 at 1, lines 9-12.

A: MSR proposes that the Administrator be able to "'lend' reserves from one entity to another at the highest prevailing interest rate of the lending entity (avoided interest cost)."[46]

Q: What is your response to this proposal?

A: This proposal contradicts how BPA actually manages its reserves. All of BPA's financial reserves are held in the same account, the Bonneville Fund, and are available to the Administrator to meet payment obligations regardless of business unit accounting.[47] Power Services and Transmission Services have separate reserves only in that BPA tracks them separately.[48]

MSR's references to a business line as an "entity" underscores its misunderstanding of BPA's financial management. As BPA staff stated in the Initial Proposal, all BPA's revenues from Power Services and Transmission Services are deposited into the single Bonneville Fund.[49] Likewise, all of BPA's disbursements necessary to operate its Power Services and Transmission Services business units and repay the Federal investment in the Federal Columbia River Power and Transmission Systems are made from this account.[50] Most significantly, "[a]ll funds in the Bonneville Fund are available to the Administrator to meet payment obligations."[51]

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

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[46] Arthur, BP-18-E-MS-12 at 33, lines 9-11.
[47] Harris et al., BP-18-E-BPA-17 at 3, lines 2-5.
[48] *Id.* at 3, lines 1-2.
[49] *Id.* at 2, lines 12-14.
[50] *Id.* at 2, lines 14-17.
[51] *Id.* at 2, lines 17-18.

based on BPA as one entity. This is why we constructed our counterproposal to gauge the sufficiency of financial reserves at the agency level.

Even though BPA has only one bank account, it attributes interest credits to each business line based on the amount of reserves attributed to such business line.[52] For example, in a data request response, BPA confirmed that "Transmission's interest credit would be calculated from all reserves attributed to Transmission."[53] In other words, each business line already receives full value from any attributable reserves in the form of lower net interest expense.

MSR's proposal would not serve a useful purpose for the Power or Transmission business lines individually or for BPA as a whole.

Q: Does this conclude your testimony?

A: Yes.

[52] Response to data request MS-BPA-26-4 (attached as Exhibit A).
[53] *Id.*

EXHIBIT A
TO REBUTTAL TESTIMONY OF JP05 ON
FINANCIAL RESERVES POLICY

Responses to Data Requests Cited in BP-18-E-JP05-02

Response To Data Request PP-BPA-26-16

Request Detail

Request ID: PP-BPA-26-16
Page Number: 35
Line Number: 14-20
Exhibit Filing: BP-18-E-BPA-17

Technical Contact Name: Michael Deen
Technical Contact Phone: 503.595.9774
Technical Contact Email: mdeen@ppcpdx.org
Legal Contact Name: Irene Scruggs
Legal Contact Phone: 503.595.9779
Legal Contact Email: iscruggs@ppcpdx.org

Request Text: Does BPA believe that that there would be an issue meeting all of its non-Federal financial obligations during the upcoming rate period under status quo financial policy? If so, please provide any analysis to support this conclusion along with supporting documentation and workpapers.

Response Detail

Date Response Filed: 12/8/2016 3:41:31 PM
Contact Name: Marcus Harris
Contact Phone: 503.230.5931
Contact Email: maharris@bpa.gov
Response Text:
BPA's modeling of liquidity over the rate period does not suggest there is an issue meeting non-Federal obligations. However, the amount of liquidity necessary to ensure short term solvency, which the status quo TPP policy assesses, is generally a lower requirement than the amount of liquidity that would need to be maintained to support BPA's credit rating.

Response To Data Request MS-BPA-26-4

Request Detail

Request ID: MS-BPA-26-4
Page Number: 9
Line Number: 4-13
Exhibit Filing: BP-18-E-BPA-17

Technical Contact Name: Peter Scanlon
Technical Contact Phone: 202.467.6370
Technical Contact Email: pjs@dwgp.com
Legal Contact Name: Peter Scanlon
Legal Contact Phone: 202.467.6370
Legal Contact Email: pjs@dwgp.com

Request Text: Your testimony states: "Because use of the Treasury Facility would reduce Power rates but would not reduce Transmission rates, BPA decided for the 2010 rate case that it would allocate for ratemaking purposes the entire Treasury Facility to Power rates. Introduction of the larger Treasury Facility had the effect of reducing the level of financial reserves needed for Power Services to meet the 95 percent TPP standard. In the 2010 rate case, BPA relied upon $300 million of the Treasury Facility to satisfy Power within-year liquidity needs; the remaining $450 million was available to support Power TPP. Starting with the 2012 rate case, BPA has assumed $320 million of the Treasury Facility to be available for Power within-year liquidity needs and $430 million to be available for Power TPP support." (a)Is it correct that when your testimony says BPA relied on the treasury facility you mean for the study, and not that the treasury Facility was actually drawn upon for Power's liquidity in operation? (b)If not, please identify the amounts that the Treasury Facility was drawn upon to support Power's liquidity during the 2010, 2012, 2014 and

2014 rate case periods. (c) Did Power ever operationally rely on reserves available for risk to meet its liquidity needs? (d) If so, what was the maximum amount of reserves for risk drawn down by Power to meet liquidity during each rate period? (e) Did Power ever draw on more reserves for risk than Power had available? In other words, did Power draw on reserves for risk attributed to transmission? (f)Please explain how interest earned on reserves is treated if Power has net negative reserves for risk, and transmission has positive net negative reserves for risk.

Response Detail

Date Response Filed: 1/10/2017 3:08:26 PM
Contact Name: Byrne Lovell
Contact Phone: 503.230.3930
Contact Email: belovell@bpa.gov
Response Text:

(a) Yes. (b) Not applicable given answer to (a). (c) Yes. (d) BPA's financial reserves are BPA's primary source of liquidity. Similar to a personal checking account, nearly all monetary payments are paid with available financial reserves. In the same sense, virtually all receipts add to reserves. In this way, reserves are both depleted and replenished throughout the fiscal year without regard to whether the dollars flowing in or out of BPA were set aside in ratemaking for risk, liquidity, or some other purpose. For this reason, BPA cannot identify a specific event where the "maximum amount" of reserves for risk was used. A better indicator for the total amount of reserves for risk used to meet liquidity would be to compare the beginning and ending balances of reserves for risk for a fiscal year. A negative difference between these two values would indicate the magnitude that reserves for risk had been used to meet liquidity needs during the year. The largest decline in reserves for risk over the past decade would be FY 2010, where BPA's power reserves fell from $552 million to $233 million. (e) BPA objects to this question as unduly burdensome and outside of the scope of this case. The question asks if BPA "ever" drew upon financial reserves attributed to Transmission, which would require extensive research for periods as far back as the 1980s and 1990s when separating transmission and power accounting began. Without waiving this objection, and considering only BPA's practices since 2001, the answer is yes. At the end of FY 2002, BPA had reserves of $188 million, of which $197 million were attributed to Transmission. Thus, Power had negative $9 million in reserves. (f) The interest credit calculations for Power and Transmission are described in PS-BPA-26-21. If the reserves value (e.g., for Power) is negative, the interest credit is negative for that business line. In the event described in answer (e), the interest credit for Transmission was based on all reserves attributed to Transmission, including any reserves Power may have relied on, not on the actual reserves in the BPA Fund at Treasury. For example, as noted above in answer (e), Power reserves were negative $9 million, agency reserves were $188 million, and reserves attributed to Transmission were $197 million. Transmission's interest credit would be calculated from all reserves attributed to Transmission ($197 million) not the reserves actually in the BPA Fund ($188 million). Power would be assessed an interest expense for the $9 million in Transmission reserves Power used. In this way, Transmission customers are not harmed by Power's short-term operational reliance on reserves attributed to Transmission.

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: March 14, 2017.

s/ Irene A. Scruggs

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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	**)**	

REBUTTAL TESTIMONY OF:
Public Power Council
Powerex Corp.
as
JOINT PARTY 1

SUBJECT:
BPA SOUTHERN INTERTIE HOURLY RATE

WITNESSES:
Michael Deen
Kevin Wellenius

March 14, 2017

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SUBJECT: REBUTTAL TESTIMONY OF JOINT PARTY 1 REGARDING BPA's SOUTHERN INTERTIE HOURLY RATE

SECTION 1: INTRODUCTION AND PURPOSE OF REBUTTAL TESTIMONY

Q: Please state your names and qualifications.

A: My name is Michael Deen. My qualifications are shown at BP-18-Q-PP-03.

A: My name is Kevin Wellenius. My qualifications are shown at BP-18-Q-PX-02.

Q: Are you the same witnesses who previously submitted direct testimony on behalf of Joint Party 1 in this proceeding?

A: Yes, we are.

Q: What is the purpose of your rebuttal testimony?

A: The purpose of this rebuttal testimony is to address the direct testimony submitted on behalf of Joint Party 3 (JP03) as BP-18-E-JP03-01.

Q: Who is Joint Party 3?

A: We understand JP03 to consist of three California entities: the Sacramento Municipal Utility District (SMUD), the Turlock Irrigation District (Turlock) and the Transmission Agency of Northern California (TANC). According to their direct testimony, the members of JP03 are California municipal utilities and/or transmission providers on the California side of the California-Oregon Intertie.

Q: Please briefly summarize your rebuttal testimony.

A: This testimony rebuts three of the core claims made by JP03. *First,* JP03 alleges that BPA staff's "fear of loss of revenue" from future long-term firm service on the Southern Intertie "is unfounded." In this rebuttal testimony, we demonstrate that there is objective public evidence that BPA transmission customers may not be as willing to commit to long-term service as has historically been the case.

Contrary to JP03's assertions, it is both prudent and appropriate for BPA to take steps to encourage transmission customers to commit to long-term firm service.

Second, JP03 alleges that BPA staff's hourly rate proposal constitutes an impermissible shift from "cost-based" ratemaking to "value-based" ratemaking. In this rebuttal testimony, we demonstrate that BPA staff's rate proposal is nothing of the sort, and instead is based on changing a single parameter in BPA's longstanding cost-based formula for calculating rates for hourly transmission service.

Third, JP03 speculates that BPA staff's proposed rate for hourly service on the Southern Intertie, if adopted, would lead to a litany of adverse consequences. The claims regarding adverse consequences to Northwest consumers are either demonstrably wrong or simply mis-state the role of transmission service in the functioning of regional markets. JP03's claims regarding adverse consequences to California consumers are flawed, further highlight that the *status quo* is beneficial to California interests, and should be beyond the proper scope of the BPA's rate determination.

In addition to rebutting the substantive points mentioned above, this rebuttal testimony also identifies numerous factual errors in the JP03 testimony, as well as mischaracterizations of the Administrator's BP-16 Final Record of Decision (ROD) and material presented in the BP-18 pre-rate workshops.

Q: *How is your rebuttal testimony organized?*

A: Section 2 responds to JP03's assertion that BPA staff's "fear of loss of revenue is unfounded." Section 3 responds to JP03's claim the BPA staff's hourly rate proposal represents a shift from cost-based ratemaking to "value-based" ratemaking. Section 4 responds to JP03's prediction of adverse consequences if BPA staff's hourly rate proposal is adopted. Section 5 documents various errors in the JP03 testimony.

SECTION 2: BPA STAFF'S CONCERNS REGARDING FUTURE SALES OF LONG-TERM SERVICE ON THE SOUTHERN INTERTIE ARE AMPLY SUPPORTED BY OBJECTIVE PUBLIC DATA

Q: What does JP03 claim regarding the prospects for BPA to continue selling high levels of long-term transmission service on the Southern Intertie?

A: JP03 dismisses any concerns that sales of long-term transmission service on the Southern Intertie might decline. Specifically, JP03 asserts that "[t]he fear of the loss of revenue from long-term subscriptions for Southern Intertie north-to-south service is unfounded."[1]

Q: Does JP03 dispute that seams issues have undermined the priority of firm service on the Southern Intertie?

A: No. JP03 agrees that there are seams issues affecting the Southern Intertie, and agrees that steps should be taken to address these issues.[2]

Q: Does JP03 deny that requests for long-term service have, in fact, declined sharply since the BP-16 rate proceeding?

A: No, JP03 acknowledges that the queue for long-term service requests has, indeed, declined since the prior rate case. However, JP03 insists that this does not imply any risk to BPA's ability to sell long-term service on the Southern Intertie.

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[1] Holcomb *et al.*, BP-18-E-JP03-01, at 15 lines 20-21.

[2] *See, e.g.,* Holcomb *et al.*, BP-18-E-JP03-01, at 92 lines 1-16.

Q: Do you agree?

A: No. Continued sales of long-term transmission service occur either through a transmission customer committing to renew their own expiring reservations, or through a transmission customer committing to new long-term service. In either case, a transmission customer must first submit a request into BPA's queue to initiate the process that leads to a new or renewed transmission service agreement.

Stated differently, a decline in the queue for new service requests means that a necessary condition for BPA to enter into a new transmission service agreement cannot be met. If long-term transmission service becomes available—including, for instance, if a transmission customer declines to renew all of its expiring service—BPA will offer service to transmission customers with a request for new service in the queue, in the order the request was submitted. If the quantity of long-term transmission service that is available for sale exceeds the quantity of requests for new long-term service in the queue, then the path will not be fully subscribed on a long-term basis.

Importantly, the queue for new service requests represents the *maximum* quantity of new long-term service that BPA would be able to sell, since these requests give the transmission customer that submits them the option—but not the obligation—to commit to long-term service. A transmission customer with a request in the queue may still choose to decline transmission service when service is offered by BPA, for instance, or a transmission customer may choose to withdraw its request from the queue at any time.[3] The actual quantity of long-term service that is ultimately sold could therefore be considerably *less* than the quantity of new service requests in the queue.

For these reasons, the shrinking size of the queue for new service requests is highly relevant to BPA's ability to continue to sell long-term firm service on the Southern Intertie.

Q: *How does the queue for new long-term service compare to the quantity of long-term service agreements that could terminate during the BP-18 rate period?*

A: BPA staff provided a spreadsheet showing the requests in the queue as of November 30, 2016.[4] That spreadsheet shows a total of 195 MW of new long-term service requests on the AC Intertie in the North-to-South direction, but only 95 MW of those requests extend beyond the end of the BP-18 rate period. This represents just 8% of the 1,142 MW of long-term service reservations that will terminate during the BP-18 rate period, absent renewal.[5]

The same spreadsheet shows a total of 767 MW of new long-term service requests on the DC Intertie in the North-to-South direction, but none of those requests extends beyond January 2019. During the BP-18 rate period, 1,152 MW

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[3] Examples of each of these actions were discussed in our direct testimony. *See* Deen, *et al.* BP-18-E-JP01-1, at 7, line 18, to 8, line 15.

[4] *See* "LTF_Pending_Queue_11_30_2016.xls," attached to BPA staff response to SM-BPA-26-100, included in Attachment A.

[5] Information regarding long-term reservations that will expire if not renewed is from BPA staff's September 29, 2015 presentation ("BPA Staff September 2015 Presentation"), at slide 16, *available at:* https://www.bpa.gov/Finance/RateCases/BP-18/Meetings/IS%20HNF%20Workshop_2015-09-29.pdf. This presentation is not reproduced in this testimony or the attachments due to volume but is incorporated by reference. In addition, 8 MW of long-term capacity is currently available on this path.

of long-term service reservations on this path will terminate unless they are renewed.[6]

Q: *Given that the quantity of potentially expiring rights exceeds the queue for new long-term service, how does JP03 anticipate that North-to-South service will be fully subscribed?*

A: JP03's belief that there is no reason for the Administrator to be concerned about BPA's future sales of long-term firm service on the Southern Intertie appears to be based on its expectation that BPA transmission customers will renew expiring rights. However, the small volume of requests for new service makes this a risky bet, since even a small quantity of non-renewal of expiring rights could result in available long-term capacity in excess of requests for new service.

The most obvious case is on the DC Intertie, where 1,152 MW of long-term rights may terminate during the BP-18 rate period, but the queue spreadsheet shows no requests for new service beyond January 2019. Without requests for new service in the queue, the renewal rate on DC Intertie reservations expiring during BP-18 rate period would need to be 100% in order for the path to remain fully subscribed on a long-term basis.

Similarly, on the AC Intertie, the renewal rate would need to be at least 92% to achieve full subscription of the path on a long-term basis, given the requests for new service discussed above. This renewal rate would be just equal

[6] BPA Staff September 2015 Presentation, at slide 17.

to the average FY 2011-2016 renewal rate for the path.[7] In other words, the low quantity of requests for new service means there is no "buffer" in the event that renewals during the BP-18 rate period are less than in the past for the AC Intertie, or less than 100% on the DC Intertie.

Q: *JP03 also asserts that the queue for new service requests is not materially different than in the past. Do you agree?*

A: No. Even the information presented by JP03 shows that the queue contains a significantly lower quantity of requests for new service than in prior rate proceedings.[8] But a comparison of the queue at the start of this rate proceeding with the queue at the start of the previous rate proceeding in BP-16 provides an even more stark comparison.

In November 2014, just prior to the start of the BP-16 rate case, the queue for new long-term North-to-South service on the AC Intertie contained 2,020 MW, of which 1,550 MW were requests extending beyond the end of the BP-16 rate period.[9] The requests for new service represented 214% of the 725 MW of

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[7] *See* BPA "Regional White Paper, Presentation and Analysis of Southern Intertie Hourly Non-Firm Alternatives" ("BPA Regional White Paper"), at Appendix B (showing FY 2011-2016 renewals, including 1,309 MW out of 1,417 MW (92%) renewed on the AC Intertie, and 2,199 MW out of 2,249 MW (98%) renewed on the DC Intertie), *available at:* https://www.bpa.gov/Finance/RateCases/BP-18/Meetings/White%20Paper_IS%20HNF_V3_FINAL.pdf. The BPA Regional White Paper is not reproduced in this testimony or the attachments due to volume but is incorporated by reference.

[8] *See* Holcomb *et al.*, BP-18-E-JP03-01-AT02 at Tbl. 1 (pg. 8) (showing 962 MW of requests as of November 2016. Even if one discounts requests withdrawn from the queue by Powerex, as JP03 argues, the queue is still well below the 6,000 – 8,000 MW that JP03's Table 1 shows for 2014).

[9] Based on BPA staff response to SM-BPA-26-100, PendingQueue_11_10_14.xlsx, included in Attachment A.

long-term reservations on that path that were due to terminate during the BP-16 rate period and were not already committed under new reservations.[10]

On the DC Intertie, the requests for new long-term service totaled 3,887 MW in November 2014, of which 3,497 MW were requests extending beyond the end of the BP-16 rate period. The requests for new service represented 300% of the 1,165 MW of long-term reservations on that path that were due to terminate, absent renewals, during the period.[11]

At the time of the BP-16 rate proceeding, therefore, the queue of new long-term service requests on the Southern Intertie provided an ample buffer in the event that some—or even all—of the expiring long-term reservations were not renewed. By the start of the *current* rate proceeding, that buffer had all but vanished, making BPA almost entirely reliant on service renewals for continued sales of long-term service on the Southern Intertie.

Q: *What basis does JP03 provide for assuming that expiring service will be renewed?*

A: JP03 points to renewal activity during FY 2016, in which all expiring long-term service reservations were renewed,[12] but this single data point is neither representative of renewal activity nor a guarantee of future renewals. Historical

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[10] BPA Staff September 2015 Presentation, at slide 16, shows a total of 1,425 MW of long-term reservations on the AC Intertie had a service stop date during the BP-16 rate period. However, a new 700 MW reservation had already been confirmed several years earlier, reducing the quantity that would expire absent renewal to 725 MW.

[11] BPA Staff September 2015 Presentation, at slide 17.

[12] *See, e.g.,* Holcomb *et al.*, BP-18-E-JP03-01, at 17, lines 19-21 and at 19, lines 1-2.

renewals on the Southern Intertie for the period FY 2011-2016 averaged well below 100%, as documented in pre-rate workshop material presented by BPA staff.[13] Logically, individual rate periods would have experienced even lower rates of renewals than the six-year average. Furthermore, the total quantity of long-term reservations expiring in FY 2016 was 741 MW, while the quantity that will expire during the BP-18 rate period is more than three times as large.[14] JP03's position seeks to extrapolate the high renewal activity of a single data point and apply it to a significantly larger quantity of upcoming renewal decisions that must be made during the BP-18 rate period.

Q: *What do you conclude from the above evidence?*

A: By the start of this rate proceeding, the queue of requests for new long-term service on the Southern Intertie had diminished significantly, and included only 95 MW of requests on the AC Intertie extending beyond the end of the BP-18 rate period, and 0 MW on the DC Intertie extending beyond the end of the BP-18 rate period. This leaves BPA's sales of long-term service on the Southern Intertie exceedingly vulnerable to whether or not transmission customers decide to renew the nearly 2,300 MW of long-term reservations that will otherwise expire during the BP-18 rate period. Even if transmission customers renew these reservations at historical renewal rates, this volume of requests for new service in the queue is insufficient for the Southern Intertie to be fully subscribed on a long-term basis. If renewals decline to below historical rates—consistent with concerns expressed

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[13] BPA Regional White Paper, Appendix B.

[14] BPA Staff September 2015 Presentation, at 16 and 17.

to BPA by its transmission customers—then the Southern Intertie may have significant unsold long-term ATC in the north-to-south direction for the first time in recent memory.

For the foregoing reasons, we strongly disagree with JP03's view that BPA staff's "fear of the loss of revenue from long-term subscriptions for Southern Intertie north-to-south service is unfounded." We believe that BPA staff is correct to propose measures in this rate proceeding to strengthen incentives for transmission customers to choose long-term service on the Southern Intertie. To do otherwise would be to place a high-stakes bet that transmission customers will renew all, or nearly all, long-term service that will otherwise terminate during the BP-18 rate period. While JP03 argues that BPA should take that bet, the risk of such a gamble falls squarely on BPA and its customers—and not on the members of JP03 or other California interests.

SECTION 3: BPA STAFF'S SOUTHERN INTERTIE HOURLY RATE PROPOSAL IS COST-BASED AND CONSISTENT WITH BPA'S LONGSTANDING RATE DESIGN METHODOLOGY

Q: What does JP03 claim regarding the rate design methodology underpinning BPA staff's hourly rate proposal for the Southern Intertie?

A: JP03 asserts that BPA staff's hourly rate proposal "represents a radical shift away from cost-based ratemaking to value-based ratemaking[.]"[15]

Q: Do you agree?

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[15] Holcomb *et al.*, BP-18-E-JP03-01, at 4, lines 11-12.

A: No. BPA staff's proposal is based on the same general formula that was proposed, and approved, in the BP-16 rate proceeding, and in the rate proceedings before that. The sole difference lies in the use of a value of 25 hours per week instead of 80 hours per week when allocating the annual cost of service to individual hours of service. Thus, there is no "radical shift" in BPA staff's proposal.

Q: What is the basis for JP03's contention that BPA staff's proposal is "value-based"?

A: JP03 appears to base its claims on the broader discussion related to the Southern Intertie seams issues, and the fact that numerous transmission customers expressed their concerns in BPA's pre-rate workshops that the value of BPA long-term firm service on the Southern Intertie has been undermined. While these considerations are highly relevant to why the Administrator directed BPA staff to explore both rate and non-rate actions related to the Southern Intertie, BPA staff's actual hourly rate proposal is based strictly on allocating the annual cost of service for the Southern Intertie segment among different durations of service.

Q: Does JP03 challenge BPA's use of an hourly denominator in calculating the hourly rate?

A: Yes. In particular, JP03 asserts that "BPA proposes reducing the divisor for hourly service from 80 to 25 as 'appropriate' based on the assumption that '[c]ustomers relying on hourly products are likely to purchase the products in fewer hours.' … This is clearly rate design based on usage patterns (not on the cost to provide the service)[.]"[16] But JP03 appears not to realize that the previous use of 80 hours per week was also in recognition of the fact that customers relying on hourly products are likely to purchase the products in a limited number of hours. JP03's critique is simply an attack on BPA's longstanding, and well-established, approach to calculating hourly rates, and does not raise any issues specific to the change proposed by BPA staff.

Q: Does JP03's testimony demonstrate that it is improper, or a departure from "cost based" ratemaking, to set rates based on the expected hours that a transmission product will be used?

A: No. In fact, JP03's testimony shows just the opposite. In a section on "industry ratemaking standards," JP03 cites multiple examples in which cost-based rates for hourly service include assumptions regarding the number of hours that a customer will choose to use that product. For instance, JP03 quotes a decision explaining that "a utility's … hourly firm transmission rate is based on a sixteen-hour day."[17] JP03 also quotes another decision in which rates for non-firm transmission service are "premised on the assumption that a customer who uses the transmission system for the 16 peak hours of the day should pay the same contribution to fixed costs as a customer who has reserved capacity on a daily basis[.]"[18]

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[16] Holcomb *et al.*, BP-18-E-JP03-01, at 35, lines 13-16 (emphasis omitted).

[17] Holcomb *et al.*, BP-18-E-JP03-01, at 90, lines 7-8 (quoting *Entergy Services, Inc.*, 85 FERC ¶ 61,163 (1998)).

[18] Holcomb *et al.*, BP-18-E-JP03-01, at 90, lines 10-12 (quoting *Midwest Independent Transmission System Operator, Inc.*, 118 FERC ¶ 61,095 at P 84 (2007)).

JP03 also points to the tariff rates of other OATT transmission providers in the WECC. But these rates simply demonstrate that it is "standard" for transmission providers to establish rates for hourly service that imply that transmission customers will use that service in only a subset of hours.[19]

Q: *What do you conclude regarding JP03's claim that BPA staff proposed rate for hourly service on the Southern Intertie is "value based"?*

A: JP03's claims that BPA staff's proposed rate is a "radical shift" from cost-based ratemaking, and that it constitutes "value based" ratemaking, are baseless. BPA staff's proposed rate is calculated using the same formula as in prior rate periods. This formula recognizes that hourly customers may only use—and will only pay for—hourly service in a subset of hours. This concept is well-established and consistent with the rate design of other transmission providers, as demonstrated by JP03's own evidence. Ultimately, JP03's "value based ratemaking" claim requires it to demonstrate that the use of 80 hours per week constitutes cost-based ratemaking, but the use of 25 hours per week would somehow constitute "value-based" ratemaking. Nothing in JP03's testimony supports such a conclusion.

SECTION 4: JP03'S CLAIMS OF ADVERSE CONSEQUENCES UNDER BPA STAFF'S HOURLY RATE PROPOSAL ARE UNFOUNDED AND IRRELEVANT

Q: *What does JP03 claim will occur if BPA staff's hourly rate proposal is adopted?*

A: JP03 makes numerous claims about the consequences of accepting BPA staff's proposed hourly rate. These include an increase in costs to California entities,

[19] Holcomb *et al.*, BP-18-E-JP03-01-AT02 at Tbl. 8. An hourly rate that is simply the monthly rate divided by the total hours in a month would have resulted in a "Ratio of Hourly to Monthly" equal to 1.38. Eight of the nine transmission providers in JP03's Table 8—including the members of JP03—exceed this value.

including the members of JP03, the potential collapse of energy markets at COB and NOB, as well as a drop in energy prices at Mid-Columbia, which JP03 asserts will be detrimental to Northwest entities. None of these claims raise credible or legitimate arguments against BPA staff's proposed hourly rate.

Q: What is your response to the claim that the proposal will be economically detrimental to California entities, including JP03's members?

A: First and foremost, it is unclear how this argument is relevant to BPA's primary consideration of setting rates in a manner that recovers the cost of service and providing an appropriate incentive for customers to invest in long-term service. Even JP03's own testimony argues that "if the rates recover BPA's costs and do not exceed the costs to serve the customer, that is all that the cost-based objective permits."[20] Second, JP03's assertions of the economic consequences to California interests from changes to BPA's Southern Intertie hourly rate simply underscores that the *status quo* has been favorable and beneficial to those California entities. This is consistent with concerns raised in the pre-rate workshops that seams issues on the Southern Intertie have resulted in the inequitable transfer of benefits to California entities to the detriment of BPA's transmission investment, cost recovery, and rate stability interests. It should not be surprising that JP03 would strongly oppose a change to the present conditions.

As to JP03's specific claims of harm to regional markets, they are

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[20] Holcomb *et al.*, BP-18-E-JP03-01, at 9, lines 22-23.

hyperbolic and not supported by credible evidence. JP03 raises the spectre that BPA staff's proposal could impact "the continued viability of hourly markets at COB/Nevada Oregon Border[.]"[21] Given that only around 2% of energy deliveries on the Southern Intertie have historically been made using hourly BPA transmission service,[22] it is simply not credible for JP03 to claim that the proposed changes to the rate for hourly service will disrupt market liquidity or cause the "collapse of hourly markets at COB." Furthermore, as explained in our direct testimony, any unintended consequences that actually arise—however unlikely—can be adequately mitigated through BPA's authority to discount the hourly rate, at its discretion.

Finally, JP03's calculation of $1.3 million in anticipated cost increases is flawed, and actually demonstrates the effectiveness of BPA staff's proposal in addressing certain of the "seams issues" concerns expressed by transmission customers at public workshops.

Q: How is JP03's calculation flawed?

A: JP03 calculated SMUD's anticipated harm simply by multiplying its 2016 purchases of "hourly energy" at COB by the proposed change in the hourly transmission rate.[23] However, JP03's calculation assumes that every future

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[21] Holcomb *et al.*, BP-18-E-JP03-01, at 10, lines 9-10.

[22] *See* "Scheduling Data_updated 20151015.xlsx" (showing hourly energy schedules by each type of transmission product for FY 2009-2015), *available at:* https://www.bpa.gov/Finance/RateCases/BP-18/Meetings/Scheduling%20Data_updated%2020151015.xlsx. The foregoing data is not reproduced in this testimony or the attachments due to volume but is incorporated by reference.

[23] Holcomb *et al.*, BP-18-E-JP03-01, at 12, lines 5-13. *See also* JP03 response to BPA-JP03-26-15, included in Attachment A ("…The $1.3 M estimate is the amount of 2016 energy transacted hourly, 168,962 MWh, multiplied by the proposed increase in hourly Southern Intertie rates of $7.96/MWh: 168,962 MWh x $7.96/MWh = $1,344,938[.]").

purchase will cost an additional $8/MWh, which is simply unsupported. The higher proposed rate for hourly transmission service will only apply to energy delivered using that type of service; purchases delivered on other types of transmission service will not incur the higher rate. In discovery, JP03 admitted that it is unable to determine how much—if any—of SMUD's 2016 energy purchases at COB were delivered using BPA hourly transmission service.[24] Consequently, JP03 cannot claim that *any*—let alone all—of its energy purchases will incur the proposed increased transmission cost.

Elsewhere in the testimony, JP03 appears to argue that energy purchase costs might rise due to the proposed rate increase causing prices at COB to increase by the same amount.[25] This ignores the fact that energy delivered from the Northwest to COB must compete with energy produced in California, or delivered to California on other major transmission paths.

Finally, it must also be recognized that the "harm" anticipated by JP03 is the flip side of changes that would benefit Pacific Northwest consumers by restoring appropriate incentives for investment in long-term firm transmission service on the Southern Intertie.

Q: What is your response to JP03's claim that the hourly rate proposal will depress energy prices at Mid-C?

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[24] *See* JP03 response to BPA-JP03-26-14(b) (included in Attachment A) ("Hourly import schedules at COB can use both hourly rights and long term transmission rights to get to COB. SMUD does not have the data necessary to determine the percentage of hourly schedules delivered to SMUD at COB using hourly versus some other longer-term service.").

[25] Holcomb *et al.*, BP-18-E-JP03-01, at 62, lines 1-4.

A: JP03 asserts that it "expect[s] that Mid-C index prices will fall as a result of the export tax, because there will be more instances when the higher hurdle rate forces down Mid-C prices in order for the delivered price at COB/NOB to be competitive."[26] This claim is convoluted and unsupported. For JP03's prediction of depressed Mid-C to come true, at least two conditions would need to be met. First, the quantity of energy exported out of the Northwest and delivered over the Southern Intertie would need to fall as a result of the proposed hourly rate. Second, the reduction in energy delivered over the Southern Intertie would need to be large enough to affect market prices at Mid-C. JP03 has provided no evidence to support either of these conditions. Moreover, JP03's theory that the hourly rate on the Southern Intertie works as an "export tax" or a "hurdle rate" is at odds with the fact that very little of the energy scheduled on the Southern Intertie uses hourly transmission service, and hence very few of those transactions actually pay the hourly rate.

Q: What do you conclude from the above discussion?

A: In an attempt to preserve the rates for use of the Southern Intertie, which happen to be favorable to its members, JP03 predicts a range of harmful consequences that are unsupported by evidence or sound logic. Moreover, these dire predictions are refuted by the fact that JP03's members themselves have adopted tariff rates for hourly service on the southern segments of the Southern Intertie that are very

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[26] Holcomb *et al.*, BP-18-E-JP03-01, at 70, line 21, to 71, line 1.

similar to the rate proposed by BPA staff.[27]

SECTION 5: JP03'S TESTIMONY CONTAINS NUMEROUS ERRORS AND DISTORTIONS

Q: *Do you have other concerns with JP03's testimony?*

A: Yes. JP03's testimony contains numerous errors that undermine its credibility. In particular, the JP03 testimony: (1) misrepresents the Administrator's BP-16 Final ROD; (2) errs in its claim that reduced hourly sales will significantly impact the rate for long-term service; (3) fails to distinguish BPA staff's current proposal from the BP-16 proposal of Joint Party 6; (4) misrepresents material from BPA's pre-rate case and regional workshops on the Southern Intertie; (5) contains obvious errors regarding the quantity of long-term firm Southern Intertie reservations held by various BPA transmission customers; and (6) makes erroneous factual claims regarding BPA's business practices.

Q: *How does JP03 mischaracterize the Administrator's Final ROD in BP-16?*

A: The JP03 direct testimony mischaracterizes the BP-16 Final ROD with regard to the Administrator's decisions and commitments on Southern Intertie rates issues. In particular JP03 claims that BPA staff did not evaluate non-rates solutions and that adopting the proposed rate solution in this proceeding—without work being completed on implementing non-rates solutions—would be contrary to the BP-16 Final ROD.[28]

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[27] *See, e.g.,* Deen *et al.*, BP-18-E-JP01-1, at 24-25, showing that TANC's tariff rate for hourly service on the COTP is $12.52/MWh, while SMUD's is $11.14/MWh. Within the past year, SMUD and TANC began to discount hourly transmission to a rate similar to BPA's *current* Southern Intertie hourly rate. LADWP, which has an on-peak hourly rate of $10.81/MWh, does not discount hourly service.

[28] Holcomb *et al.*, BP-18-E-JP03-01, at 85, lines 16-20.

The JP03 testimony mischaracterizes both the commitments made by the Administrator in the BP-16 Final ROD and also the work conducted by BPA staff, customers, and stakeholders in response to those commitments. As stated in the BP-16 Final ROD, the Administrator committed to evaluate both rate and non-rate alternatives to resolving the seams issues on the Southern Intertie. And that is exactly what BPA staff did, through a series of public workshops held during the time between the BP-16 and BP-18 rate proceedings in the ordinary course of BPA's pre-rate case workshops. These workshops explored several discrete aspects of the seams issues on the Southern Intertie, engaged stakeholders in identifying potential solutions, and assessed each potential solution based on its expected effectiveness, durability, cost, and other attributes. In our view, BPA staff has fully carried out the commitments made in the BP-16 Final ROD to "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."[29] JP03's contention amounts to a requirement that BPA *implement* non-rate solutions prior to pursuing changes to rates, but there is no such requirement in the BP-16 Final ROD.

Further, as we have noted in our direct testimony, nothing about BPA staff's rate proposal would limit or inhibit continued evaluation and implementation of non-rate solutions by BPA, either on its own or in conjunction with other transmission service providers on the Southern Intertie.

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[29] BP-16-A-02 at P-2.

Q: *How does JP03 mischaracterize the relationship between long-term rates and hourly sales?*

A: JP03 states that "increasing the hourly rates will reduce sales of hourly service on the Southern Intertie. … This would increase the long term firm transmission rates."[30] But JP03 does not disclose how minimal any such effect would be. In fact, one can readily calculate what the long-term rate would be if there were assumed to be no hourly sales at all. The resulting rate would be approximately $0.055/kW per month higher than the proposed BP-18 rate.[31] JP03's claims are especially misleading because it ignores that there would be a far greater impact to long-term rates if BPA had to recover its annual revenue requirement from a smaller quantity of long-term and short-term sales.

Q: *How does JP03 fail to distinguish BPA staff's current proposal from the rate proposal of Joint Party 6 in BP-16?*

A: The JP03 testimony cites arguments raised in the BP-16 proceeding regarding an hourly rate design proposed by Joint Party 6. The concern was that JP06's proposal, which was based on recent historical use of hourly service, could lead to a "ripple effect" or "vicious cycle" wherein the rate for hourly service is increased, leading to reduced use of hourly service, which then leads to a further

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[30] Holcomb *et al.*, BP-18-E-JP03-01, at 83, line 23, to 84, line 3.

[31] The alternative annual rate is calculated by dividing the annual revenue requirement ($94,705,000) by the total cost allocations sales excluding any hourly sales (6,324 – 268), which is equal to $15.638/kW per year, or $1.303/kW-mo. This compares to the proposed BP-18 long-term rate of $1.248/kW-mo.

increase in the rate for hourly service in the subsequent rate case, and the cycle repeats itself until substantially all usage of hourly service disappears.[32]

However, these concerns from the BP-16 proceeding have no applicability to BPA staff's proposal in BP-18. This is because the hours per week divisor in BPA staff's proposal is not based on historical usage of hourly transmission service, but rather on fundamental patterns of demand on the California grid. Therefore, BPA staff's rate design proposal does not tie future rates to a potential "vicious cycle" as claimed by JP03. Further, BPA staff's analysis supporting the initial proposal fully considers and accounts for the anticipated effects of the rate design change on hourly sales.[33]

Q: How does JP03 mischaracterize certain material presented in BPA's pre-rate case workshops?

A: JP03 mischaracterizes a presentation by FTI Consulting presented during BPA's September 29, 2015 public workshop on the Southern Interties. In one instance, JP03 claims that the FTI presentation "acknowledged that if the hourly rates are tripled, firm rights holders, as a group, will be able to extract economic rents in three ways…"[34] JP03 does not provide a specific citation to this alleged statement, nor can it, for such a statement does not appear anywhere in the cited presentation.[35]

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[32] Holcomb *et al.,* BP-18-E-JP03-01, at 33, lines 14-21.

[33] BP-18-E-BPA-08 at 26.

[34] Holcomb *et al.*, BP-18-E-JP03-01, at 78, lines 10-11.

[35] JP03 included selected pages of the FTI presentation in BP-18-E-JP03-01-AT03, at 47-53. The full presentation can be found at https://www.bpa.gov/Finance/RateCases/BP-18/Meetings/150929%20FTI%20presentation.pdf, and it also does not contain the alleged statements.

Q: *How did JP03 misstate the quantity of long-term Southern Intertie reservations held by various BPA transmission customers?*

A: JP03 purports to calculate the quantity of long-term firm reservations on the Southern Intertie, in the North-to-South direction, held by various BPA transmission customers. The results are presented in JP03's Tables 5, 7a, and 7b. These results are also repeated in numerous portions of JP03's testimony. The analysis, which JP03 claims is based on the witnesses' query of BPA's OASIS, is demonstrably and dramatically incorrect. For instance, Table 7a, labelled "Long-Term Southbound Intertie Capacity Rights (MW)" shows rights totaling 8,199 MW. The corresponding number in Table 7b, presenting information purportedly as of October 1, 2018, is 7,943 MW. Both numbers greatly exceed BPA's total Southern Intertie capacity of 5,715 MW, which can be found in JP03's own exhibits.[36] JP03's numbers also contradict the customer-specific information provided by BPA staff in its testimony. For example, JP03 erroneously states that BPA Power Services' long-term Southern Intertie rights total 410 MW[37], while BPA staff's evidence puts the number at 915 MW.[38] Similarly, JP03 erroneously states that Powerex's long-term Southern Intertie rights total 4,005 MW[39], while

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[36] *See, e.g.,* Holcomb *et al.*, BP-18-E-JP03-01-AT03 at 19 (showing BPA ownership of 2,725 MW of the COI north of COB) and at 22 (showing BPA owns the entire 2,990 MW of the Pacific DC Intertie north of NOB).

[37] Holcomb *et al.*, BP-18-E-JP03-01-AT02 at Table 7b.

[38] BP-18-E-BPA-08 at 166, line 152. We note that this table includes Southern Intertie long-term transmission rights in both the north-to-south as well as the south-to-north direction.

[39] Holcomb *et al.*, BP-18-E-JP03-01-AT02 at Table 7b.

BPA staff's evidence shows the number as 2,035 MW.[40] While it is not clear how JP03 arrived at its numbers, it clearly failed to take elementary steps to check the accuracy of its calculations.

Q: *How does the JP03 testimony misstate BPA's business practices?*

A: JP03 claims that BPA's OATT does not "define the Transmission Provider's cost of expansion. Absent a posted cost of expansion on the Southern Intertie, there is effectively no cap on the price that a Reseller may demand."[41] JP03 appears unaware that BPA's Business Practice for Resale of Transmission Service explicitly sets cost of expansion at $27.48/MWh, and BPA has documented how this cost was determined.[42]

Q: *Does this conclude your rebuttal testimony?*

A: Yes.

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[40] BP-18-E-BPA-08 at 168, line 270. We note that this table includes Southern Intertie long-term transmission rights in both the north-to-south as well as the south-to-north direction.

[41] Holcomb *et al.*, BP-18-E-JP03-01, at 80, lines 17-19.

[42] The cited business practice was last updated in September 2013, and can be found at https://transmission.bpa.gov/ts_business_practices/Content/6_Requesting/resale.htm.

ATTACHMENT A
TO REBUTTAL TESTIMONY OF JOINT PARTY 1

Exhibit 1: Data Request and Response SM-BPA-26-100

Exhibit 2: Data Request and Response BPA-JP03-26-14

Exhibit 3: Data Request and Response BPA-JP03-26-15

EXHIBIT 1

Request ID: SM-BPA-26-100			
Request Date	**Cite**	**Request Text**	**Response Text**
12/08/16	Exhibit: BP-18-E-BPA-12 Page(s): 7-8 Line(s): 17-6	See also BPA's response to SM-BPA-26-39(a). Please provide the data requested on a monthly basis in Excel format. SMUD is requesting only the data, not any analysis of such data.	Response filed: 12/15/16 Please see attached files. File(s) Submitted for this Response: Historical_Queue_Data.zip[1]

[1] The attachment is not reproduced in this Attachment due to volume.

EXHIBIT 2

Request ID: BPA-JP03-26-14			
Request Date	**Cite**	**Request Text**	**Response Text**
02/06/17	Exhibit: BP-18-E-JP03-01 Page(s): 12 Line(s): 6-7	You state that hourly energy is used “overwhelmingly” to cover variances in load forecasts between day-head and real-time loads and resources: a. How do you define “overwhelmingly”? Did you conduct a study that identified a specific %? If so, please provide all studies, analysis, and work papers. b. Is hourly energy necessarily scheduled on hourly transmission service? If not, how much hourly energy was delivered to SMUD using hourly firm transmission service on BPA-owned portions of the Southern Intertie from 2009-2016 by year? How much hourly energy was delivered to SMUD using other Pacific Northwest transmission providers’ shares of the Southern Intertie from 2009-2016 by year? c. To the extent that hourly transmission service is used to deliver the hourly energy, what portion of the transmission is “Original” hourly requests and what share is redirected off of a longer term contract? d. Do any of the parties in Joint Party 3 purchase transmission directly from BPA for this purpose? If not, what mechanisms are used to assign the costs of transmission to the parties in Joint Party 3 and what share of the transmission costs are the parties in Joint Party 3 assigned?	Response filed: 02/13/17 a. ”Overwhelmingly” in this case means at least 90% of SMUD’s hourly transactions in 2016. b. Hourly import schedules at COB can use both hourly rights and long term transmission rights to get to COB. SMUD does not have the data necessary to determine the percentage of hourly schedules delivered to SMUD at COB using hourly versus some other longer-term service. c. SMUD does not have transaction-specific data sufficient to know the answer to this question. d. TID has not purchased long-term firm transmission on the Southern Intertie from BPA. However, TID acquired long-term transmission rights on the Southern Intertie from PNGC. TID also purchases hourly and longer transmission on the Southern Intertie from BPA and others. TANC does not purchase transmission capacity from BPA, and as such is not assigned a share of the costs of purchased BPA transmission capacity. Southern Intertie transmission costs are not “assigned” to JP03 members. Some prices for delivered energy at COB include an explicit transmission component, but others do not because the price is "bundled, delivered". The specific details of such pricing depend on the preferences of the buyer and the seller, and may vary from product to product and over time.

EXHIBIT 3

Request ID: BPA-JP03-26-15			
Request Date	**Cite**	**Request Text**	**Response Text**
02/06/17	Exhibit: BP-18-E-JP03-01 Page(s): 12 Line(s): 13	Please provide the calculations used to arrive at your $1.3M estimate of additional annual costs. What is the rationale for assuming the cost of all the delivered energy would increase by the change in the hourly transmission rate? Please cite all data sources used.	Response filed: 02/13/17 This initial estimate assumes that 2016 is a "typical year" for hourly purchases of energy at COB and that the full transmission rate increase is passed on to buyers. JP03 recognizes that the "incidence" of the export tax may well fall on both suppliers (lower prices) and buyers (higher prices). The $1.3 M estimate is the amount of 2016 energy transacted hourly, 168,962 MWh, multiplied by the proposed increase in hourly Southern Intertie rates of $7.96/MWh: 168,962 MWh x $7.96/MWh = $1,344,938

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing on the Bonneville Power Administration's Office of General Counsel, the Hearing Clerks, 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: March 14, 2017.

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

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

REBUTTAL TESTIMONY OF:

Public Power Council

SUBJECT:
Montana Intertie Rate

WITNESS:
Michael Deen

March 14, 2017

BP-18-E-PP-02

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SECTION 1: INTRODUCTION

Q: Please state your name and qualifications.

A: My name is Michael Deen. My qualifications are shown at BP-18-Q-PP-03.

Q: What is the purpose of your testimony?

A: The purpose of this testimony is to address proposals advanced by Renewable Northwest, and by the Montana Environmental Information Center ("MEIC") and Sierra Club to eliminate or roll in the Montana Intertie Rate ("IM rate" or "IM-18 rate"). The testimony also addresses a proposal by Renewable Northwest to "update" the Townsend-to-Garrison Rate ("TGT rate").

Q: Please summarize your conclusions.

A: The Administrator should reject proposals by Renewable Northwest, MEIC, and Sierra Club to eliminate the IM rate, roll in the Eastern Intertie segment, or modify the TGT rate. Rejection of those proposals would be consistent with BPA staff's segmentation study and methodology, as well as the final decisions made by the BPA Administrators in the BP-12, BP-14, and BP-16 rate cases on this issue. No compelling new evidence warrants these decisions being revisited.

The IM rate is not a significant impediment to the competitiveness of Montana resources, particularly wind, and eliminating the rate would have no significant effect on Montana resource development or subscription of Eastern Intertie capacity. However, eliminating the IM rate would pose a significant cost risk to BPA's Network transmission customers and is likely to be construed as potentially harmful precedent. Retirement of the Colstrip generating facilities has no material impact in this rate case. BPA should work with interested customers and stakeholders following the BP-18 rate proceeding to determine what, if any, changes to BPA rates or policy may be needed in the future to address the retirement of Colstrip generating facilities.

Q: *How is your testimony organized?*

A: This introduction constitutes Section 1. Section 2 addresses and rebuts the direct testimony of Renewable Northwest. Section 3 addresses and rebuts the direct testimony of MEIC and Sierra Club.

SECTION 2: RENEWABLE NORTHWEST PRESENTS NO COMPELLING EVIDENCE TO REVERSE BPA'S PRIOR DECISIONS

Q: *Have you reviewed the direct testimony of Renewable Northwest in this proceeding, filed as Exhibit BP-18-E-RN-01?*

A: Yes. Renewable Northwest recommends that the IM rate be eliminated and the TGT rate be "updated" because these rates are allegedly not cost-based. Renewable Northwest cites the passage of Oregon's Clean Electricity and Coal Transition Plan legislation, as well as the planned retirements of Colstrip Units 1 and 2 no later than July 2022, and asserts that the IM rate and TGT rate are not cost-based. Renewable Northwest also asserts that its proposal would eliminate a "duplicative and excessive" rate pancake and be beneficial to BPA and its customers.

Q: *Please describe the claim that the IM and TGT rates are not cost-based.*

A: This claim is based on the observation that the revenue credits and IM rate revenues associated with the Eastern Intertie segment currently exceed the segmented revenue requirement by approximately $1 million. This surplus of revenues is driven by BPA's contractual ability to collect from the Colstrip Transmission System ("Colstrip TS") partners up to $12.5 million annually for the facilities while the segmented revenue requirement is approximately $11.7 million. BPA credits these additional revenues towards the revenue requirement of other segments.

Q: Does this situation mean that the IM and TGT rates are not cost-based?

A: No. First, the TGT rate and the IM rate are cost-based by definition. BPA is appropriately collecting revenues to which it is entitled under the Montana Intertie Agreement. The Montana Intertie Agreement provides for the construction and operation of the Eastern Intertie, cost allocation among the parties to the agreement, and transmission service by BPA over the Eastern Intertie.[1] Specifically, the costs associated with building and maintaining the Eastern Intertie are recovered from the Colstrip parties through the TGT rate. Thus, the TGT rate is set to recover BPA's actual costs of building, maintaining, and operating the Eastern Intertie facilities. It is a negotiated rate that is available exclusively to the Colstrip owners, is set according to the Montana Intertie Agreement,[2] and cannot be unilaterally "updated" by BPA.

Likewise, the IM rate is set to recover costs – set pursuant to the Montana Intertie Agreement – of BPA's firm capacity requirements on the line (in this case 16 MW out of a possible 200 MW). As explained above, the Montana Intertie Agreement is based on BPA's costs of constructing and maintaining the Eastern Intertie facilities and the TGT and IM rates are set based on the agreement between the parties on how those costs should be recovered through time. These steps represent sound business practice and follow cost causation principles. Because BPA's proposed rates are based on the actual costs of the Eastern Intertie, both TGT and IM rates are appropriate and cost-based.

[1] *See* Administrator's Final Record of Decision, 2014 Wholesale Power and Transmission Rate Adjustment Proceeding ("BP-14 ROD"), BP-14-A-03, at 176 (July 2013).
[2] *See* Administrator's Final Record of Decision, BP-16 Rate Proceeding ("BP-16 ROD"), Appendix C: Transmission, Ancillary and Control Area Service Rate Schedules, BP-16-A-02-AP03, at 33 (July 2015).

Second, although the TGT rate is designed so that "[a]nnual revenues plus credits for government use should equal annual costs of the facilities," it recognizes that "in any given year there may be a surplus or a deficit."[3] The rate schedule specifically provides that "[s]uch surplus or deficit for any year shall be accounted for in the computation of annual costs for succeeding years."[4] The Montana Intertie Agreement has been updated many times at the mutual agreement of the parties to reflect changes in the costs. To the extent there are "surplus" revenues from the TGT and the IM rates in any particular year, those revenues are appropriately allocated to the benefit of other segments because those segments that would have to pay for any potential deficit in Eastern Intertie revenues.

Q: What are Renewable Northwest's specific proposals for modifying the TGT and IM rates?

A: Renewable Northwest proposes to "reduce the annual revenue requirement for the Eastern Intertie by $1.039 million, recalculate the TGT rate accordingly, eliminate the IM rate, and begin charging Network rates for service over BPA's portion of the Eastern Intertie starting at Townsend."[5] If BPA does not adopt this recommendation, Renewable Northwest recommends that "BPA should eliminate the IM rate and allocate the surplus revenue from the TGT rate ($1.039 million) to the revenue requirement for BPA's portion of the Eastern Intertie as it becomes subscribed."[6]

Q: What do you recommend with regard to these proposals to modify the TGT rate and eliminate the IM rate?

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[3] BP-16 ROD, Appendix C at 33.
[4] *Id.*
[5] Yourkowski, BP-18-E-RN-01 at 10, lines 17-19.
[6] *Id*. at 12, lines 10-12.

A: The proposals should be rejected. The idea that BPA should collect less revenues than it is contractually entitled to collect is contrary to any sound business judgment. The Montana Intertie Agreement is based on BPA's costs of constructing and operating the facilities and is agreed to by all parties. As described above, the current allocation of revenue credits from the Eastern Intertie to other segments follows cost causation principles because the allocation of the credits matches the risk of under-recovery. As detailed later in this testimony, eliminating the IM rate would not provide any substantial benefits, would run contrary to BPA's segmentation methodology in this proceeding, and would pose a substantial cost risk to Network customers that do not benefit from the Eastern Intertie facilities. The Renewable Northwest proposal would constitute unsound business practice, violate cost causation principles, and inappropriately shift risks and costs among transmission customers, and should be rejected by the Administrator.

Q: Please describe the claim that the IM rate constitutes an excessive or duplicate charge and is in violation of the pricing policies of the Federal Energy Regulatory Commission (FERC).

A: Renewable Northwest claims that customers taking service over the Eastern Intertie must pay both an embedded rate for BPA's service on the Network segment and an "incremental" charge through the IM rate. The claim is that this would violate the FERC "or" pricing policy that allows transmission providers to charge the higher of an incremental cost or embedded cost rates but not both. Renewable Northwest goes on to claim that BPA charging both the Network rate and the IM rate constitutes a duplicative and excessive rate pancake.

Q: *Please respond to Renewable Northwest's claim regarding an excessive or duplicative rate pancake.*

A: Renewable Northwest is incorrect in its assertion and fundamentally misunderstands the applicable rate-setting principles. Both the IM and Network rates are set on the basis of the embedded cost of their respective facilities, meaning there is no possible violation of FERC "or" pricing guidelines. Because the rates recover the costs of *different* facilities, they are intrinsically not duplicative. Finally, because the rates are set based on embedded costs, they are inherently not excessive.

Q: *What are Renewable Northwest's assertions regarding the impact of the IM rate on the competitiveness of generating resources located in Montana?*

A: The testimony points out that the IM rate could add approximately $2 per MWh for a 40% capacity factor resource or approximately $1 per MWh for an 80% capacity factor resource. As it unsuccessfully argued in the prior rate cases, Renewable Northwest argues here that this constitutes a significant impediment to the development of wind generation in Montana.

Q: *Is this a significant impediment to the development of generating resources in Montana, particularly wind resources?*

A: No. Firstly, it is important to consider the relative magnitude of the charges in question. Based on the recently published 7th Power Plan from the Northwest Power Planning and Conservation Council, new wind resources in the region would have a levelized cost of energy in the range of $94 to $110 per MWh.[7] A $2-per-MWh charge is a relatively

[7] *See* "Seventh Northwest Conservation and Electric Power Plan" ("7th Power Plan"), Appendix H at H-25 to H-29. Accessible online at: https://www.nwcouncil.org/media/7149910/7thplanfinal_appdixh_gresources.pdf

small component of this overall amount and is likely to be overwhelmed by other, more impactful considerations in choosing between projects.

Further, based on the extensively-documented and regionally-vetted analysis of generating resources in the 7^{th} Power Plan, Montana wind is fully competitive with other resources even including the IM rate. In fact, the 7^{th} Power Plan analyzed five "reference" wind plants, four of which were located in Montana and one of which 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.[8] This recent analysis from the Northwest Power and Conservation Council directly contradicts Renewable Northwest's claim that the IM rate impedes the competiveness of Montana resources, particularly Montana wind.

Q: *Would eliminating the IM rate substantially encourage the development of Montana wind resources?*

A: No. As the Administrator concluded in the BP-16 Final ROD, "[i]t is unlikely that, by itself, elimination of the IM rate would result in additional Montana wind generation."[9] The Administrator further explained the reasoning behind his conclusion:

> Moreover, 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 unlikely. NorthWestern Energy, the likely transmission provider for Montana wind generation to BPA's Network, currently posts only 49 MW of available transfer capability to BPA at Townsend. BPA has only 184 MW of available capacity on the Eastern Intertie. BPA's Network is constrained over the West of Garrison and West of Hatwai flowgates. Transmission requests in BPA's transmission queue that would use those flowgates exceed the available transfer capability. Therefore, given current

[8] *See* 7^{th} Power Plan, Appendix H at H-25 to H-29.
[9] BP-16 ROD at 126.

> transmission constraints, it is unlikely that eliminating the IM rate would lead to significant renewable resource development in Montana.[10]

To the best of our knowledge, these same transmission constrains will continue to exist and impede the development of wind resources in Montana during the BP-18 rate period.

Q: What is the purported relevance to the IM rate in this proceeding of the planned closures of Colstrip Units 1 and 2, as well as Oregon's passage of the Clean Electricity and Coal Transition Plan legislation, which could lead to additional closures of Colstrip facilities in the future?

A: Renewable Northwest alleges that these two factors increase the importance of eliminating the IM rate to encourage both the full subscription of the Eastern Intertie and also to avoid the loss of Network revenues. Renewable Northwest alleges that BPA would experience a decline in Network revenue between $5.9 and $11.8 million if the expiring capacity associated with the Colstrip units is not "repurposed or otherwise subscribed."[11]

Q: Are these valid concerns supporting the elimination of the IM rate in this proceeding?

A: No. As a first matter, eliminating the IM rate would have no bearing on the economic viability of the Eastern Intertie capacity. Colstrip parties that pay the TGT rate do not also pay the IM rate for that capacity. Additionally, there is no compelling evidence that the Colstrip Units 1 and 2 will be shut down during this rate period. There is also no reason to assume that BPA's Network segment revenues would be substantially reduced even in the event of those units closing without replacement generation utilizing the Eastern Intertie. Buyers of the Colstrip output would still need to serve their native load

[10] BP-16 ROD at 125 (internal citations omitted).
[11] Yourkowski, BP-18-E-RN-01 at 6, lines 4-7.

and are highly likely to do so in large part with power transported over BPA's Network segment.

Q: *What actions do you recommend be taken on account of the future closures of Colstrip generating facilities?*

A: We strongly recommend that no action be taken as part of this proceeding. Eliminating the IM rate would have no positive effects to mitigate hypothetical effects of the eventual Colstrip closures. Further, many complicated contractual and policy considerations may be involved depending on what the Colstrip transmission customers may wish to do with their rights following the closures. Simply put, there are far too many speculative elements outside the scope of this proceeding to warrant any rate action. We recommend that BPA work with interested parties following the rate case to examine potential future actions on a holistic basis.

Q: *What assertions does the Renewable Northwest make regarding the potential rate impacts of eliminating the IM rate?*

A: Renewable Northwest asserts that any impact would be de minimis and could potentially benefit BPA's network customers.[12]

Q: *Do you agree with this assessment?*

A: No. As BPA makes clear in the BP-16 Final ROD, the "de minimis" rate impact calculations that Renewable Northwest cites from the BP-16 rate proceeding only consider existing facilities.[13] Elimination of the IM rate and/or roll-in of the Eastern Intertie segment would potentially expose existing Network customers to responsibility for massive costs for the transmission upgrades and balancing capacity that would be

[12] Yourkowski, BP-18-E-RN-01 at page 13, lines 4-11.
[13] *See* BP-16 ROD at 125.

needed to actually move a significant amount of wind generation from Montana to the BPA Network. These costs could easily be measured in the hundreds of millions to more than a billion dollars.

Q: *Do you have any other concerns with the Renewable Northwest Proposal to eliminate the IM rate?*

A: Yes. Elimination of the IM rate or roll in of the Eastern Intertie segment could be viewed as a precedent for arguments to roll in BPA's Southern Intertie Segment. For example, were the IM rate to be eliminated, the argument that Renewable Northwest makes regarding the "duplicative" nature of the IM rate could be argued as a precedent to the Southern Intertie. Roll-in of the Southern Intertie segment would have a much more substantial impact on Network rates which could lead to rate shock and instability.[14] Also, both interties are used for the primary purpose of transporting energy to and/or from locations that are remote to the BPA Network and external to 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. The elimination of the IM rate to facilitate renewable energy imports could be argued as a precedent for roll-in of the Southern Intertie facilities for the same purpose, to the detriment of Network customers and contrary to the purpose for the segmentation of those facilities.[15]

[14] Estimated at 12.5% in the BP-16 proceeding. BP-16 ROD at 125.
[15] A discussion of the potential concerns regarding precedent and impacts for Southern Intertie roll-in is located in the BP-16 ROD at 125-126.

SECTION 3: SIERRA CLUB AND MEIC PRESENT NO NEW OR COMPELLING ARGUMENTS FOR BPA TO REVERSE ITS EXISTING POLICY

Q: Have you reviewed the direct testimony filed by Sierra Club and MEIC in this proceeding?

A: Yes. This includes both the testimony of Thomas J. Schneider, filed as Exhibit BP-18-E-SC-01-V01, and the testimony of Robert M. Fagan, filed as Exhibit BP-18-E-SC-02-V01.

Q: Please describe the substantive arguments and conclusions of Mr. Schneider's testimony regarding the segmentation of the Eastern Intertie.

A: The testimony of Mr. Schneider provides a lengthy narrative on his perspective of the historical events that led to the construction of the Eastern Intertie facilities. The fundamental argument presented is that BPA played a role in building and in justifying the need for the Eastern Intertie facilities to Montana regulators. In particular, Mr. Schneider asserts that part of the justification for the facilities was energy needs of the Pacific Northwest "including the rapidly growing loads of BPA's Montana cooperative customers."[16] The testimony goes on to assert that:

> In my opinion, the Townsend to Garrison segment is and has always been part of BPA's regional transmission network in its service area. I respectfully submit that BPA's decision to segment the Eastern Intertie and establish the separate additional Montana Intertie Rate violates sound ratemaking practices and fails to recognize the underlying and integrated nature of BPA's participation the Colstrip transmission project from the outset.[17]

Therefore, Mr. Schneider asserts that the segmentation of the Eastern Intertie has never been justified on the basis of cost causation and that the segment should be eliminated and/or rolled in to the Network.

[16] Schneider, BP-18-E-SC-01-V01 at 11, lines 10-11.
[17] *Id.* at 11, lines 14-20.

Q: *Please respond to these assertions and the recommendation to eliminate the Eastern Intertie segment.*

A: Mr. Schneider's narrative, arguments, and conclusions are not compelling. As a first matter, it is not in dispute that BPA played a key role in building the Eastern Intertie facilities. However, that fact has no dispositive value in determining the proper segmentation of the facilities for cost recovery. The fact of the matter is that the Eastern Intertie facilities were constructed explicitly for the purpose of importing power from the Colstrip generating facilities, which are outside of the Pacific Northwest, and that is exactly what the facilities are used for today. The facilities are not and have not been used for load service by BPA.

BPA recovers the costs of the Eastern Intertie facilities through the TGT rate, which recovers the costs from those customers that caused the line to be built and BPA to incur costs, for the importation of power from Colstrip. BPA also recovers the costs of using those same facilities by customers importing energy from other resources. This is and has historically been the same use of the line since its construction, and nothing in the rate case record indicates that this will change.

Interestingly, Mr. Schneider's perspective on the purpose of the Eastern Intertie facilities is flatly contradicted by the testimony of Mr. Fagan, the other witness for the Sierra Club and MEIC in this proceeding. Mr. Fagan testifies "The Montana Intertie consists of 500 kV transmission facilities constructed to deliver Colstrip energy to the Pacific Northwest."[18]

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[18] Schneider, BP-18-E-SC-02-V01 at 4, lines 17-18.

Given the use and purpose of the Eastern Intertie facilities to import energy from remote resources by a limited number of customers, BPA's proposed segmentation of the Eastern Intertie is and will continue to be appropriate for the BP-18 rate period. Mr. Schneider's arguments to roll in the segment are baseless and should be rejected by the Administrator.

Q: *Does Mr. Schneider make any other arguments for why the IM rate should be eliminated?*

A: Yes. Mr. Schneider cites the future closure of Colstrip generating facilities, the passage of Oregon's updated renewable portfolio standard, the EPA's Clean Power Plan regulations, and popular demand for renewable energy in Oregon according to poll conducted by the Sierra Club. Mr. Schneider also asserts that there would be virtually no cost or risk from eliminating the IM rate.

Q: *Are these arguments persuasive?*

A: No. We have already addressed arguments regarding the future closure of Colstrip generating units that are currently planned or further closures that may occur due to Oregon's passage of the Clean Electricity and Coal Transition Plan legislation in rebuttal to the testimony of Renewable Northwest. The Administrator rejected arguments in BP-16 that elimination of the IM rate would have any significant effect on compliance with Clean Power Plan regulations.[19] Given that the IM rate is not a significant impediment to renewable resource development and that eliminating the rate would have minimal effect to promote such development, this remains a logical conclusion. Finally, a poll of Oregon residents conducted by the Sierra Club and presented as evidence in its

[19] *See* BP-16 ROD at 125.

own testimony has no value whatsoever in this proceeding. BPA rates are set according to statutory requirements and business principles and not by alleged popular demand. Finally, as discussed above in rebuttal to Renewable Northwest, the assertion that eliminating the IM rate would carry no cost or risk to other BPA transmission customer is patently false.

Q: *Please summarize the conclusions of Mr. Fagan's testimony for the Sierra Club.*

A: Mr. Fagan alleges that eliminating the IM rate would make Montana wind resources more competitive and encourage subscription of the remaining portion of BPA's share of the Eastern Intertie capacity with minimal cost or risk impacts. As already discussed, Mr. Fagan also correctly contradicts the conclusions of Mr. Schneider regarding the use and purpose of the Eastern Intertie.

Q: *Please respond to these conclusions.*

A: With the exception of the use and intended purpose of the Eastern Intertie facilities, Mr. Fagan's conclusions are incorrect. As we have discussed above in response to Renewable Northwest, the IM rate is not an impediment to the competiveness of Montana wind resources and eliminating the rate would not have a substantial effect on resource development. For this reason, it is unlikely that eliminating the IM rate would have any significant impact on the subscription level of BPA's share of the Eastern Intertie capacity. Further, as discussed previously, eliminating the IM rate would come at significant cost risk to Network transmission customers and would be contrary to the purpose of BPA's appropriate segmentation of the Eastern Intertie facilities. As such, Mr. Fagan's recommendation to eliminate the IM rate should be rejected by the Administrator.

Q: Does this conclude your testimony?

A: Yes.

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: March 14, 2017.

s/ Irene A. Scruggs
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