NT CUSTOMER RESPONSE
TO THE COMMENTS OF
THE PTP COALITION, THE LISTED PTP CUSTOMERS, AND
IBERDROLA RENEWABLES AND PACIFICORP

I. INTRODUCTION

This response is submitted on behalf of the following association members and individual utilities: Clark Public Utilities, Eugene Water & Electric Board, Cowlitz PUD, Lewis PUD, Northwest Requirements Utilities, PNGC Power and the Western Public Agencies Group (collectively "NT Customers").

The NT Customers rely on the Network Integration Transmission Service ("NT") from the Bonneville Power Administration ("BPA") to reliably deliver power to meet the electrical needs of their retail customers at an economical rate. For this reason, the NT Customers appreciate this opportunity to respond to the proposals made by the Point to Point ("PTP") Customer Coalition ("PTP Coalition")[1], Listed PTP Customers[2], and Iberdrola Renewables and PacifiCorp[3] that BPA should use either a 1 Non-Coincidental Peak ("1 NCP") or 1 Coincidental Peak ("1 CP") methodology for allocating wholesale transmission costs for its Network segment.

Over the last several months, BPA has performed the peak demand tests used by the Federal Energy Regulatory Commission ("FERC") to determine which coincident peak allocation methodology is appropriate for its transmission system. The undeniable conclusion from these tests is that BPA has a 12 CP system and should be allocating wholesale transmission costs on a 12 CP basis. Indeed, as readily pointed out by the PTP Coalition, "BPA has effectively met [the FERC] 12 CP test[s] since 1996."[4]

Nonetheless, the PTP customer groups propose that BPA reject 12 CP and instead use a 1 NCP or, perhaps, a 1 CP allocation methodology. In support of this contention the PTP customer groups offer the following six general arguments:

(1) FERC's cost allocation tests are inapplicable to BPA's transmission system due to its unique nature.

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[1] Comments of Point to Point Customers Coalition on Bonneville Power Administration's Cost Allocation Alternatives, March 30, 2012, available at http://www.bpa.gov/corporate/ratecase/docs/PTP_Customers_Coalition.pdf ("PTP Coalition Comments").

[2] Comments of Listed PTP Customers on Bonneville Power Administration's Cost Allocation Alternatives, March 30, 2012, available at http://www.bpa.gov/corporate/ratecase/docs/Listed_PTP_Customers.pdf ("Listed PTP Comments").

[3] Comments of Iberdrola Renewables & PacifiCorp on Bonneville Power Administration's Cost Allocation Alternative, March 30, 2012 available at http://www.bpa.gov/corporate/ratecase/docs/Iberdrola___PacifiCorp.pdf ("Iberdrola Comments").

[4] PTP Coalition Comments at 3.

a. The large amount of PTP service on BPA's system biases the FERC tests towards 12 CP.

b. 1 NCP is appropriate because the NT MOA[5] ensures NT customers access to 65% of the aggregated nameplate capacity of all designated network resources and the firm transmission necessary to deliver that amount.

c. 12 CP should not be used because it has not been shown that BPA plans its system primarily on the basis to meet its twelve monthly peaks.

(2) BPA effectively grandfathered the use of 1 NCP for all future rate periods when it selected 1 NCP for cost allocation in the 1996 Wholesale Power and Transmission Rate Case Record of Decision ("1996 ROD").

(3) 12 CP will inappropriately shift costs from NT customers to PTP customers.

(4) The elimination of the load shaping charge through the use of a 12 CP methodology will remove the justification for including short term sales in the denominator when calculating NT rates.

(5) BPA provides an NT service that is superior to the FERC *pro forma* tariff justifying a deviation from FERC's 12 CP allocation approach.

(6) 12 CP violates the requirement in § 10 of the Transmission System Act that BPA is to equitably allocate transmission costs between Federal and non-Federal power utilizing the system.

The remaining portions of these comments respond to each of the above arguments.

II. DISCUSSION

A. FERC's cost allocation tests are not biased but instead result in the outcome that would be expected for a system like BPA's.

The PTP Coalition asserts that because 80% of BPA's transmission customers take reservation based services[6], rather than the usage based NT service, it biases the FERC test results toward a 12 CP allocation methodology by producing a relatively flat overall peak load profile for BPA. According to the PTP Coalition, this bias is best demonstrated by performing the FERC tests but without the billing factors related to the reservation based services. With the

[5]Memorandum of Agreement for the Management of Network Integration Transmission Service for Delivery of Federal Power to Network Customer Loads (September 28, 2011), available at http://transmission.bpa.gov/Customer_Forums/nt/documents/nt_moa_agreement.pdf ("NT MOA").

[6] BPA's reservation based services include PTP, Integration of Resources ("IR") service, and Formula Power Transmission ("FPT") service.

PTP, IR and FPT billing factors removed, the PTP Coalition notes that "the tests would justify a 1 CP method under the FERC cost allocation tests."[7]

The problem with the PTP Coalition's approach is that it incorrectly applies the FERC tests by withholding approximately 80% of the billing factors from the analysis so that it achieves the result that the coalition appears to want – a non-12 CP conclusion.[8] By removing the billing factors for reservation based services, the PTP Coalition is no longer applying the FERC test but is instead creating an entirely new test to determine cost allocation for wholesale transmission services. Not only is the PTP Coalition's methodology lacking in technical or precedential support, it also conflicts with industry standard and FERC Order 888 which provides:

> The flexibility and reassignment rights of [the PTP] transmission service require the transmission provider to hold the firm contract capacity available regardless of the customer's own load characteristics or its actual use. In other words, a transmission provider's obligation to plan for, and its ability to use, a transmission customer's reserved capacity is clearly defined by that customer's contract reservation. For these reasons, it is appropriate to consider a firm reservation as the equivalent of load for cost allocation and planning purposes.[9]

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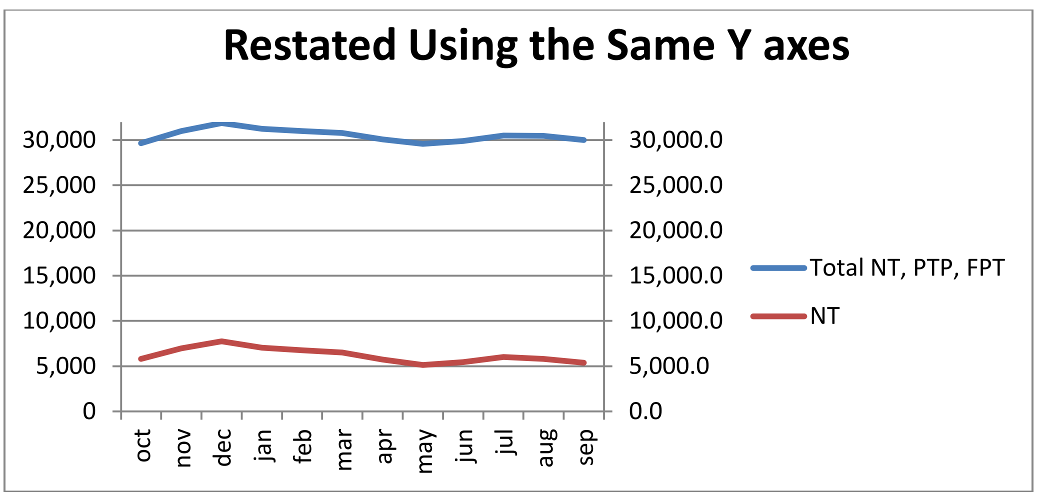
[7] PTP Coalition Comments at 1-2.

[8] The PTP Coalition comments included a graph presented to show that although BPA's total system peak load profile is flat; the NT customer load profile is volatile. However, the graph seriously distorts the volatility of the NT customers' billing factors when compared to the total system billing factors. This is because the graph decreases the value on the right hand Y axis by a factor of four compared to the left hand Y axis which is used for the total billing factors. This has the visual effect of exaggerating the impact of NT loads on the overall load on the transmission system. The graph below maintains the same Y axes for total system load and NT loads based on the average FY 2006 to FY 2011 billing data provided by BPA at the February 8, 2012 workshop. It provides a much more balanced picture of the effect of NT billing data compared to total billing data.



[9] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21,540-01, 21,600 (May 10, 1996) ("Order 888").

In any event, the PTP Coalition's entire premise is wrong. The purpose of the FERC tests is to measure the "flatness" of the transmission system's monthly peaks over the course of the year. As indicated by Order 888, by its very nature the PTP service creates flatness. The fact that there is large amount of reservation based services on BPA's system does not inappropriately skew the results of the FERC tests by showing an artificially flat peak profile for purposes of the tests. Rather, it causes the FERC tests to show BPA's system exactly as one with a very flat peak profile due to the high level of reservation based services on the system. Under such circumstances, FERC would require a jurisdictional utility to use a 12 CP allocation methodology.

FERC is not alone in its approach. The table below is a demonstrative, though by no means comprehensive, list indicating that 12 CP is the industry standard for both jurisdictional and non-jurisdictional utilities.

Utility	**Allocation Methodology**
Avista Corporation	12 CP - monthly demand charge using a load ratio share calculated on a rolling twelve month basis[10]
British Columbia Hydro and Power Authority	12 CP – monthly demand charge using a load ratio share calculated on a monthly basis[11]
Idaho Power Company	12 CP - monthly demand charge using a load ratio share calculated on a rolling twelve month basis[12]
PacifiCorp	12 CP – stated $/MW-month rate calculated using the average of the 12 monthly system peaks[13]
Portland General Electric Company	12 CP - monthly demand charge using a load ratio share calculated on a rolling twelve month basis [14]
Puget Sound Energy	12 CP - monthly demand charge using a load ratio share calculated on a rolling twelve month basis[15]
Western Area Power Administration	12 CP - monthly demand charge using a load ratio share calculated on a rolling twelve month basis [16]

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[10]Avista Corporation, FERC Electric Tariff Filing, Volume No. 8 (11/17/2011), §§1.19, 34.1, 34.2, 34.3, available at http://www.oatioasis.com/AVAT/AVATdocs/OATT_effective_10-1-2011__11-17-2011.pdf.

[11] British Columbia Hydro and Power Authority, Open Access Transmission Tariff (1/17/2011), §§ 1.17, 34.1, 34.2, 34.3, Attachment H, available at http://www.oatioasis.com/TVA/TVAdocs/2010-TSGs.pdf.

[12] Idaho Power company, Open Access Transmission Tariff (8/5/2010) §§ 1.19, 34.1, 34.2, 34.3, Schedule 9 – Appendix A, available at http://www.oatioasis.com/IPCO/IPCOdocs/IPC_OATT_Issued_2011-03-28.pdf.

[13] PacifiCorp, Open Access Transmission Tariff, Vol. 11 (12/25/2011), §§ 34.1, 34.2, and Attachment H, available at http://www.oasis.pacificorp.com/oasis/ppw/20120209_OATTMASTERwRateCase.pdf.

[14] Portland General Electric Company, Open Access Transmission Tariff, §§ 1.19, 34.1, 34.2, 34.3, available at http://www.oatioasis.com/PGE/PGEdocs/PGE-8_OATT.pdf.

[15]Puget Sound Energy, Inc., Open Access Transmission Tariff (filed 11/14/2011) §§1.19, 34.1, 34.2, 34.3, available at http://www.oatioasis.com/PSEI/PSEIdocs/PSE_OATT_cleaned-up_&_pending_(filed_November2011).pdf.

Tennessee Valley Authority	12 CP – monthly demand charge using a load ratio share calculated on a rolling twelve month basis[17]

Accordingly, BPA's current modified 1 CP approach is already out of step with standard industry practice. If BPA were to adopt the recommendation of its PTP customers to use a 1 NCP methodology it would be well beyond what is accepted in the industry. This is because, (i) BPA should be using a 12 CP methodology even more so than other utilities because its peak profile is so flat due to the large amount of reservation services on its system; and (ii) BPA and its transmission customers have recently expended a considerable amount of time and effort to bring the terms and conditions of BPA's transmission services more in line with standard industry practice. There is no reasonable basis for not making a similar move for cost allocation. The same justification used by some PTP customers to push BPA to move its tariff closer to the FERC *pro forma* tariff also holds true for applying the 12 CP methodology, i.e., it is the industry accepted standard which provides consistency and predictability.

A 12 CP approach is also more consistent with cost causation given the cost drivers on BPA's system. As shown by the graph below[18], while NT customer loads do show variation over the year, there has been little to no growth over the last six years. Over the same time period, however, significant PTP customer growth has caused BPA to initiate extensive and expensive expansions of the Network segment. All Network customers, both PTP and NT, end up paying for this expansion in the form of higher rates even though the vast bulk of that expansion is being done to accommodate PTP growth.[19] Accordingly, the adoption of a 12 CP methodology is more consistent with cost causation because it ensures that those customers who are putting the greatest cost pressures on BPA's transmisison system, PTP customers, shoulder a larger share of the costs they are creating.

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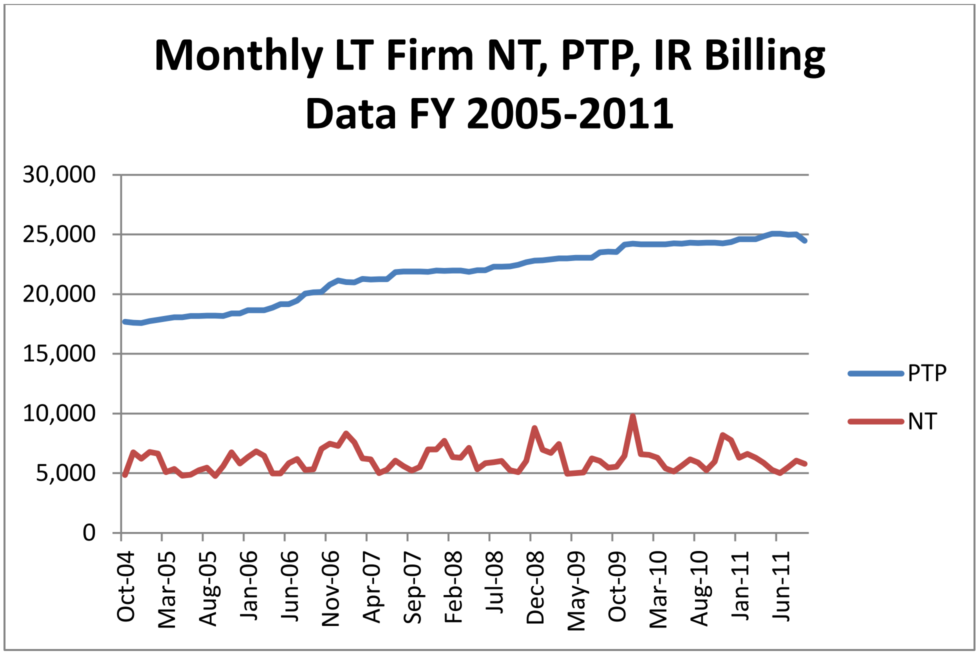
[16] Western Area Power Administration, Open Access Transmission Service Tariff (3/2/2011), §§ 1.19, 34.1, 34.2, 34.3, available at http://www.oatioasis.com/WAPA/WAPAdocs/WAPA-OATT-CLEAN-Effective-2011-0403.pdf.

[17] Tennessee Valley Authority, Transmission Service Guidelines (12/1/2009), §§ 1.23, 34.1, 34.2, 34.3, available at http://www.oatioasis.com/TVA/TVAdocs/2010-TSGs.pdf.

[18] This graph is based upon our analysis of the data provided by BPA on Februray 8, 2012. Note that PTP and IR loads are summed for purposes of generating the PTP line. This was done to capture the effect of IR to PTP conversions that have occurred over this time period.

[19] PTSA Reform Initiative Decision and Process Power Point, December 6, 2011, p. 17, available at http://transmission.bpa.gov/customer_forums/nos_gi_reform/ptsa_reform.pdf (All NOS 2008 & 2010 projects will have 6.6% rate impact on average over the next five years under the base case assuming no PTSA defaults or PTSA terminations).



B. The NT MOA has no bearing on how wholesale transmission costs should be allocated.

The PTP Coalition also looks to the NT MOA as a basis for BPA to deviate from standard industry practice for allocating wholesale transmission costs. According to the coalition, because the NT MOA ensures NT customers access to 65% of the aggregated nameplate capacity of designated BPA network resources and the firm transmission necessary to deliver such, BPA should consider the designated amount of nameplate capacity as proxy for NT customer load for allocation purposes.[20]

This argument is a red herring. Section 8(a)(2) of the NT MOA provides that 35% of the aggregate nameplate capacity of the resources identified in Exhibit A to the MOA be treated as a temporary termination of Network Resource status under Section 30.3 of BPA's tariff. The purpose of this un-designation is to ensure that compliance with Section 30.4. This is necessary because BPA has allocated 35% of the aggregate nameplate capacity of those resources for sales of one year or longer delivered on PTP transmission and to meet other grandfathered and statutory obligations. So the purpose of section 8(a)(2) is to ensure compliance with BPA's tariff obligations, not to set aside transmission capacity equivalent to 65% of the aggregate nameplate capacity of the resources listed of Exhibit A for NT service, as the PTP Coalition claims. Notably, these obligations are substantially similar as those required under FERC's *pro forma* tariff for the non-designation of Network Resources for sales delivered on PTP transmission.[21] FERC has not adopted the PTP Coalition's proxy approach where jurisdictional utilities similarly attempt to comply with these obligations in their tariffs. BPA should not do so here.

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[20] PTP Coalition Comments at 3-4.

[21] FERC *Pro Forma*, §§ 30.3, 30.4.

C. BPA plans its transmission system to meet its twelve monthly peaks.

The Listed PTP Comments argue that 12 CP is inappropriate because it has not been shown that BPA plans its system on the basis of meeting its twelve monthly peaks.[22] However, the supposition that a 1 CP or a 1 NCP allocation methodology is appropriate because BPA has historically had a single system peak is no longer valid. As BPA itself has most recently recognized, "[P]eak summer load levels are catching up with the winter levels. This is primarily due to a greater percentage of air conditioning being installed in homes and businesses."[23] Furthermore, at the February 8, 2012 workshop, BPA staff explained in detail how BPA plans its system to meet its needs throughout the year rather than to meet one annual system peak. This is achieved by first modeling four seasonal base cases for planning purposes. The results from these four base cases are then extrapolated across the remaining months. The need to model on a seasonal basis is driven largely by the fact that load and resource patterns vary with each season and, therefore, the seasonal modeling and extrapolation across the remaining months ensures that BPA can meet its reliability obligations throughout the year.[24] Under the industry standard for cost allocation this type of system planning to meet needs throughout the year, in addition to the results of the peak demand tests, indicates that BPA should be using a 12 CP allocation methodology.

D. The 1996 ROD is not controlling for purposes of the COSA.

Both the PTP Coalition and the Listed PTP Customer comments point to the 1996 ROD for proposition that BPA should adopt a 1 NCP for the COSA because a 1 NCP methodology was proposed in 1996.[25] From their point of view nothing has changed since 1996 that warrants a move to 12 CP now. Further the PTP Coalition argues that a change from 1 NCP to 12 CP "would constitute a fundamental change in the 'rules of the road' that PTP customers were unaware of when executing their PTP contracts."[26]

However, both FERC and the Ninth Circuit have rejected similar "grandfathered" rate treatment arguments in the past.[27] As stated by FERC in *Pacific Gas and Electric Co.*:

> The fact that services provided in one period are priced using a particular method does not, in and of itself, require Pacific to provide services in a different period

[22] Listed PTP Customer Comments at 2.

[23] BPA Transmission Load Service, Expand Program, Asset Management Strategy, p. 11 (March 2012), available at http://www.bpa.gov/corporate/Finance/IBR/CIR/docs/Transmission_Loadservice_DAS.pdf.

[24] Transmission Cost of Service Analysis Workshop Power Point, pp. 9-13 (February 8, 2012), available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Workshop_2-8-12.pdf ("Feb. 8th Power Point").

[25] PTP Coalition Comments at 3-4; Listed PTP Customer Comments at 2.

[26] PTP Coalition Comments at 4.

[27] See *Pacific Gas and Electric Co.*, 61 FERC P 61,394, 62,547 (1995); *California Dept. of Water Resources v. FERC*, 489 F.3d 1029, 1041 (9th Cir. 2007).

> using the same method. In the first instance, section 205 of the FPA expressly permits such changes in rates and rate methodologies. Additionally, if the Commission were obligated to "grandfather" a particular rate treatment forever simply because it was used in the past, there could never be innovation and improvement. Likewise, customers would not be able to benefit from increased competition because utilities would not have the flexibility to change their pricing as conditions change. In short, there can be no innovation or pricing flexibility even under an open-access competitive regime if utilities are held hostage to past practice. Moreover, the fact that the proposed rates are higher does not, alone, demonstrate that the rates are unreasonable.[28]

The circumstances with respect to BPA are similar. Bonneville is obligated under its organic statutes to periodically review and revise its rates.[29] Congress never intended, and BPA has never accepted, the proposition that it is cabined to past practices in devising rates for future rate periods. Instead, BPA has an established history of recalibrating its approaches to rate development. The adoption of the Tiered Rate Methodology is a recent example. The unbundling of power and transmission rates in 1996 is another. To the extent that PTP customers believed they locked in the 1 NCP allocation methodology in 1996, it was a belief held in disregard to BPA's authorities and obligations under its statutes, BPA's past practices, and the fact that even in 1996 12 CP was the industry standard for systems like BPA's. Such unawareness provides no basis for declining to move to 12 CP some 16 years after the 1996 ROD.

In addition, despite the PTP customer arguments to the contrary, there have been substantial changes to how BPA plans and manages the transmission system, as well as how customers utilize that system. These changes justify a move to 12 CP, and include the following:

- Adoption of the Regional Dialogue Policy;
- The recent and expensive expansion of the Network Segment to accommodate renewable resource development by PTP customers under BPA's Network Open Season ("NOS") and Generation Interconnection processes;
- BPA's recent filing of a reciprocity tariff with FERC for the purpose of bringing the terms and conditions of transmission service closer to the FERC *pro forma*;
- The substantial growth of customers using PTP over the last six years;
- The lack of growth in the NT customer load over the last six years;
- The development of a robust market for the reassignment of PTP rights on BPA's system; and

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[28] 71 FERC at P 62,547.

[29] 16 U.S.C. § 839(a)(1).

- The growth of summer peak loads dispelling the traditional assumption that BPA is a single peak system.

Lastly, BPA separated its transmission and power service lines in 1996, the same year FERC issued Order 888 and BPA established the NT and PTP products. As a result of these and other complex issues, the 1996 BPA transmission rates case was settled.[30] Just like every transmission rate case settlement to follow through BP-12, the very terms of 1996 settlement agreement provide that it does not create any procedural or substantive precedent in any subsequent rate proceeding.[31]

Given the lack of precedential value associated with the 1996 settlement, coupled with the changes BPA's system has experienced since 1996, BPA should adopt the 12 CP cost allocation methodology.

E. Arguments regarding rate shock are outside the scope of this COSA process.

All of the PTP customer comments raise objection to adoption of a 12 CP methodology on the basis that it will cause a significant and inappropriate "cost shift" from the rates of NT customers to the rates of PTP customers. The NT Customers view the adoption of 12 CP not as a cost shift. Rather, it is a long overdue correction of BPA's historic, improper practice of over-collecting from NT customers and under-collecting from PTP customers under the current modified 1 CP allocation methodology. In any event, the cost shift argument is really an alleged rate shock argument that, pursuant to Scope of COSA Process adopted by BPA on February 8, 2012, is outside of the scope of the COSA and instead should be brought up and considered in the rate case.[32]

F. The PTP Coalition fundamentally misstates the purpose of the load shaping charge.

The PTP Coalition asserts that adoption of 12 CP would upend the rationale behind BPA's inclusion of short term sales in the denominator when calculating both NT and PTP rates, because without the load shaping charge NT customers would "no longer have a claim to the inventory BPA uses to make short-term sales."[33]

This is a fundamental misstatement of the purpose of the load shaping charge. The charge is an outgrowth of two decisions by BPA: First, the decision to allocate wholesale transmission costs on a modified 1 CP basis; and second, the decision to set the NT Base Rate at the same level as the long term PTP rate. By setting the NT Base Rate at the same level as the PTP rate, BPA ensures that the NT Base Rate will not recover the total revenue requirement

[30] 1996 Wholesale Power and Transmission Rate Proposal Administrators Record of Decision, Attachment No. 1 (June 1996).

[31] *Id.* at 1.

[32] http://www.bpa.gov/corporate/ratecase/docs/COSA_Scope.pdf.

[33] PTP Coalition Comments at 4.

allocated to NT customers under the modified 1 CP methodology. This is because BPA does not achieve its annual system peak in all twelve months of the year, but only once per year. The load shaping charge is designed to recover the difference between what the NT Base Charge actually recovers and the total revenue requirement allocated to NT customers under the modified 1 CP methodology. It has no connection to the propriety of BPA's use of short term sales in the denominator when calculating wholesale transmission rates, including NT rates.

Furthermore, the PTP Coalition's claim that adoption of 12 CP would destroy the logical foundation for including short-term sales in the denominator when calculating NT rates is incorrect for the following four additional reasons:

1. Standard industry practice is to credit short terms sales against the numerator when calculating NT rates even under a 12 CP methodology.[34] BPA differs slightly from this approach by including short term sales in the denominator. However, the result on both NT and PTP rates are said to be the same under either approach. If BPA did not include short term sales in its calculation of NT rates under a 12 CP methodology, it would mean that BPA would once again be outside standard industry practice for cost allocation purposes.

2. NT customers are paying for the expansion of the Network to accommodate PTP customer growth through higher rates and they should receive some benefit from that investment. The Network segment is an integrated segment, meaning that all of the users of the segment share in both its costs and benefits. As described in the NT Customer's initial comments in support of the use of 12 CP and shown on the graph on page 6, BPA is significantly expanding the Network to accommodate PTP growth.[35] The costs of this expansion are being shared by both NT and PTP customers alike, resulting in higher rates for all. It would be inequitable to ask NT customers to help fund the expansion of the Network to accommodate PTP growth but then deny them the corresponding benefit of using short term sales revenue in the calculation of their rates.

3. NT Customers do contribute to the inventory BPA uses to make short term sales even under 12 CP. NT customers are allocated a proportion of all the costs associated with the Network segment. NT customers only have access to the amount of transmission needed to serve their load on any given hour, any remaining capacity is released to the market for short term sales. Therefore, NT and PTP are equally deserving of the revenues from short term sales.

4. PTP customers can sell their capacity rights while NT customers cannot. As discussed in the NT Customer's initial proposal in support of 12 CP, a significant difference between the NT and PTP services is that PTP customers can reassign/sell their capacity rights to third parties whereas NT customers cannot.[36] This right is of a significant and growing value. In

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[34] FERC Transmission Ratemaking Powerpoint, p 4 (Nov. 16, 2011), available at http://www.bpa.gov/corporate/ratecase/docs/FERC_Transmission_Rate_Making_11-10-11.pdf.

[35] NT Customer Proposal to use a 12 CP Cost Allocation Methodology for the Transmission Cost of Service Analysis, pp. 4-5, available at http://www.bpa.gov/corporate/ratecase/docs/NT.pdf ("NT Customer Proposal").

[36] NT Customer Proposal at 5-6; Order No. 888, 61 FR at 21576 ("We conclude that point-to-point transmission service, because it sets forth clearly defined capacity rights, should be reassignable. As for network transmission

its recent reciprocity filing with FERC, BPA stated that 62,356 reassignment transactions were reported on its OASIS during the 17 month period between October 1, 2010 and February 29, 2012.[37] This is a substantial increase over the 26,442 capacity reassignment transactions that FERC staff identified on BPA's system in 2009, which at the time represented approximately 79% of all such transactions in the country.[38] Under FERC's *pro forma* Open Access Transmission Tariff ("OATT"), the inability of NT customers to similarly assign or sell their unused transmission capacity in order to recoup a portion of their costs is balanced by the use of a 12 CP allocation methodology which, as discussed above, also includes crediting short term sales against the numerator when calculating NT rates.[39] The PTP Coalition's suggestion that BPA not similarly treat short terms sales would, therefore, defeat the balance struck by FERC in the *pro forma* OATT with respect to the different characteristics of the PTP and NT services.

G. BPA's tariff includes deviations from the *pro forma* tariff that benefit either PTP or NT customers or both.

The PTP Coalition identifies a number of services in its comments that it wants BPA to confirm "are appropriately allocated between NT and PTP classes of customers or transmission customers in general."[40] Supposedly, BPA's inclusion of the costs of these services in the total revenue requirement for the Network segment, rather than directly assigning those costs to NT customers, constitutes a subsidy by PTP customers of NT customers. However, as shown on the table below, the services the PTP Coalition objects to are services that BPA is required to provide under its OATT, and the sections of BPA's OATT that require BPA to undertake these obligations appear to be consistent with what is required under the FERC *pro forma* OATT. Since the FERC *pro forma* OATT rolls the costs of these services into the total revenue requirement, the PTP Coalition's request to have them directly assigned is out of step with standard industry practice.

Service Identified by Coalition	BOATT	FERC *Pro Forma*
Redispatch Service	§ 33	§ 33
Secondary Network Service	§ 28.4	§ 28.4

service, we conclude that there are no specific capacity rights associated with such service, and thus, network transmission service is not reassignable.")

[37] BPA Petition for Declaratory Order, FERC Docket No. NJ12-7, p. 36 (March 28, 2012) available at http://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20120329-5214.

[38] Federal Energy Regulatory Commission: Staff Report on Capacity Reassignment, p. 4 (April 15, 2010) available at http://www.ferc.gov/legal/staff-reports/04-15-10-capacity-reassignment.pdf ("Reassignment Report").

[39] Order No. 888-A, 62 FR at 12323 ("The bottom line is that all potential transmission customers… must choose between network integration transmission service or point-to-point transmission service. Each of these services has its own advantages and risks…In choosing between network and point-to-point transmission service, the potential customer must assess the degree of risk that it is willing to accept associated with the availability of firm transmission capacity.").

[40] PTP Coalition Comments at 5.

Determination of firm transmission commitments	§ 28.2	§ 28.2
Planning of transmission system improvements	§ 28.2	§ 28.2
Staffing for NERC compliance activities	§§ 28.2, 1.15	§§ 28.2, 1.15
Staffing for NAESB standards for NT service	§§ 28.2, 1.15	§§ 28.2, 1.15
Staffing to establish a new Network Integration Transmission Service Model	§§ 28.2, 1.15	§§ 28.2, 1.15

To the extent there are deviations between the terms and conditions contained in BPA's OATT and the terms and conditions of the FERC *pro forma* OATT, it would be erroneous to assume that they all favor NT customers. In fact, there are some deviations that benefit PTP customers, some that benefit NT customers, and others that benefit both. These deviations were adopted by BPA for a variety of policy and/or statutory reasons. A few examples of deviations that produce a superior PTP service than that contained in the FERC *pro forma* OATT include BPA's use of Evaluation of Modifications of Existing Rights ("EMER")[41] when evaluating PTP customer requests for redirects and the use of cluster studies for BPA's NOS process[42]. It is the NT Customers' belief, however, that sum balance between the various deviations, i.e., those favoring PTP customers and those favoring NT customers, would not justify the adoption of any allocation methodology other than 12 CP.

H. Use of 12 CP would not violate § 10 of the Transmission System Act.

Finally, the PTP Coalition implies that 12 CP may violate § 10 of the Transmission System Act because it would allocate costs to PTP customers based on their contract reservations and then allocate costs to NT customers based on their usage.[43] According to the coalition, this disparity would mean that costs are not being equitably allocated between Federal and non-Federal users of the system as required by § 10. However, the NT and PTP products are different products. NT is based on customer load. PTP is based on a customer's contract demand. There is nothing inequitable in taking this difference into account when allocating costs. Indeed, this is exactly what FERC already did when it established the PTP and NT framework and 12 CP cost allocation methodology in the first instance.

III. CONCLUSION

For the reasons stated above and in the NT Customers' original comments in support of 12 CP, we urge BPA to reject recommendations that it adopt a 1 NCP or 1 CP methodology for purposes of COSA cost allocation and instead use a 12 CP allocation methodology consistent with standard industry practice for systems like BPA's.

[41] BOATT § 22.2.

[42] BOATT § 19.10.

[43] PTP Coalition Comments at 4-5.