COMMENTS OF THE WESTERN PUBLIC AGENCIES GROUP IN SUPPORT OF A 12 CP COST ALLOCATION METHODOLOGY FOR THE TRANSMISSION COST OF SERVICE ANALYSIS

The utilities that comprise the Western Public Agencies Group ("WPAG") appreciate this opportunity to reaffirm their support of the NT Customer Group[1] proposal (submitted on February 29, 2012 to Tech Forum, a copy of which is attached hereto) that the Bonneville Power Administration ("BPA") adopt a 12 Coincidental Peak ("CP") methodology for the Transmission Cost of Service Analysis ("NT Customer Proposal"). These comments are intended to supplement and support that earlier submittal and, to the extent necessary, the NT Customer Proposal is expressly incorporated herein.

On March 28, 2012, BPA sent an email via Tech Forum to all "Transmission Customers and Interested Parties" stating that "BPA's team has concluded work on its Open Access Transmission Tariff" and that BPA expects that it "will announce the submission of the tariff [to the FERC] on or about March 30."

At base, BPA's announcement means that BPA has made a final decision to bring the terms and conditions of its transmission services closer in line with the terms and conditions for such services contained in the Federal Energy Regulatory Commission's ("FERC") *pro forma* Open Access Transmission Tariff ("OATT"). The WPAG utilities offer no opinion in this process as to the wisdom of BPA's decision or as to whether BPA's movement towards the terms and conditions in the FERC *pro forma* is what is best for BPA, its customers or the region. Rather, the WPAG utilities simply recognize that BPA has made its decision and that there are natural implications stemming from it.

One such implication is cost allocation in setting transmission rates and charges. As FERC itself has recognized "non-price terms and conditions cannot be designed independent of pricing and cost recovery."[2] Accordingly, in light of BPA's move toward the terms and conditions of the *pro forma*, BPA should not allow its current wholesale transmission cost allocation methodology to remain stagnant, but instead should make a parallel move towards the FERC *pro forma's* methodology for cost allocation. This would allow BPA to approach the *pro forma's* intended parity between the terms and conditions of transmission services and cost allocation.

This means that, consistent with the NT Customer Proposal, BPA should use a 12 CP methodology to allocate the costs of its Network segment amongst the various wholesale transmission services for that segment rather than the modified 1 CP methodology it currently uses. This conclusion is amply supported by the demonstrations made by BPA staff in the COSA

[1] The parties participating in the February 29, 2012 proposal included the following association members and individual utilities: Clark Public Utilities, Eugene Water & Electric Board, Cowlitz PUD, Northwest Requirements Utilities, PNGC Power and WPAG.

[2] 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 21540, 21598 (May 10, 1996).

workshops showing that if BPA were to follow FERC's allocation methodology it would use 12 CP to allocate costs.[3]

The WPAG utilities appreciate the considerable time and obvious effort that BPA staff has put into the COSA process. These workshops have been conducted in a professional manner and were effective in facilitating a meaningful dialogue between BPA and its customers on how BPA should allocate its wholesale transmission costs between the various transmission services. However, the undeniable and unchallenged conclusion from the workshops is that BPA has a 12 CP system and should use a 12 CP allocation methodology. To date, no party has provided either a scintilla of proof or a credible argument to the contrary. Therefore, based on the information above and in the NT Customer Proposal, and because all of the evidence and analysis in this process has been overwhelmingly one sided in favor of 12 CP, we urge BPA to adopt 12 CP for the COSA.

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[3] See, Transmission Cost of Service Analysis Workshop Power Point Presentation, December 5, 2011, available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Workshop_12-05-11_revised.pdf; FERC Coincidental Peak Test Power Point, January 11, 2012, p. 2, available at http://www.bpa.gov/corporate/ratecase/docs/FERC_Coincidental_Peak_Test.pdf; Transmission Cost of Service Analysis Workshop Power Point, February 8, 2012, pp. 16 & 18 , available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Workshop_2-8-12.pdf.

ATTACHMENT

NT CUSTOMER PROPOSAL TO USE A 12 CP COST ALLOCATION METHODOLOGY FOR THE TRANSMISSION COST OF SERVICE ANALYSIS

A. Introduction.

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

The NT Customers rely on the Network Integration Transmission Service ("NT") provided by BPA to reliably deliver power to their service areas to meet the electrical needs of their retail customers at an economical rate.[1] For this reason, the stability and predictability of the NT rate is a key element in their resource planning activities. The NT Customers have a vital interest in the method used by BPA to set the NT rate, and appreciate BPA's continuing efforts to engage all transmission customers in a dialogue on this topic as part of the Transmission Cost of Service Analysis ("COSA").

BPA currently uses a modified one coincidental peak ("1 CP") allocation methodology to allocate the costs of its Network segment amongst the various wholesale transmission services for that segment. However, over the course of several COSA workshops, BPA staff has demonstrated that if BPA followed the Federal Energy Regulatory Commission's ("FERC") approach to cost allocation it would use a twelve monthly coincident peak ("12 CP") allocation methodology. In light of this information and the reasons set forth below, the NT Customers propose that BPA adopt a 12 CP methodology in the COSA on the following bases:

(1) BPA's decision to better align the terms and conditions contained in its Open Access Transmission Tariff ("OATT") with the FERC *pro forma* with the objective of making a tariff filing seeking reciprocity with FERC justifies a corresponding adoption of FERC's 12 CP methodology for allocating costs.

(2) Changes on BPA's transmission system justify the use of a 12 CP methodology including:

- BPA's large scale expansion of the transmission system to accommodate non-federal resource development by PTP customers.

- The substantial growth in the secondary transmission capacity market on BPA's system.

(3) Adoption of a 12 CP methodology is consistent with the principles enunciated by BPA and customers at the beginning of the COSA process.

[1] While some of the NT Customers take Point to Point Transmission Service ("PTP") for various reasons, each of them relies on the NT service.

The remainder of this proposal describes in detail the above justifications for the adoption of a 12 CP methodology.

B. BPA Should Adopt FERC's Approach to Cost Allocation - 12 CP.

BPA has been working for the better part of a year to bring the terms and conditions of its transmission services under its OATT in line with the terms and conditions for transmission service identified in FERC's *pro forma* OATT with an aim towards making a tariff filing seeking reciprocity with FERC by the end of March 2012. BPA's decision to adopt FERC's *pro forma* terms and conditions means that BPA should also make a corresponding move to use FERC's approach for allocating wholesale transmission costs. This is because FERC's *pro forma* OATT strikes a balance between the terms and conditions of wholesale transmission services and the allocation of costs between such services.[2] To establish terms and conditions consistent with FERC's approach and then allocate costs based on some other basis would upset that balance.

While FERC does not mandate the use of any one particular coincidental peak methodology, it has primarily affirmed the use of a 12 CP allocation method because it "believe[s] the majority of utilities plan their system to meet their twelve monthly peaks."[3] FERC does allow utilities to propose an alternative to 12 CP, but only where they can demonstrate that "such alternative is consistent with the utility's transmission system planning and would not result in over-collection of the utility's revenue requirement."[4] In evaluating such determinations, FERC uses the following three peak ratio tests:

(1) **Test No. 1 -** On and Off Peak Test - This test first compares the average of the coincidental peaks in the months with the highest system peaks as a percentage of the annual system peak. Second, it compares the average of the coincidental peaks in the months with the lowest system peaks as a percentage of the annual system peak. A 12 CP allocation is considered appropriate where the difference between these two percentages is 19% or less.

(2) **Test No. 2** - Low-to-Annual Peak Test - Compares the lowest monthly peak as a percentage of the annual system peak. A range of 66% or higher is considered indicative of a 12 CP system.

(3) **Test No. 3** - Average to Annual Peak Test – Compares the average of the twelve

[2] 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 21540-01, 21598 (May 10, 1996) ("Order 888") ("We agree that non-price terms and conditions cannot be designed independent of pricing and cost recovery").

[3] Order 888, 61 FR at 21599.

[4] 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-A, 62 FR 12274-01, 12321 (March 14, 1997) ("Order 888-A").

monthly peaks as a percentage of the annual system peak. A range of 81% or higher is considered indicative of a 12 CP system.[5]

Over the last several months, BPA has performed each of the above peak demand tests several times in order to determine which coincident peak allocation methodology is appropriate for its system. Each iteration of the tests used different assumptions or data to perform the calculations (e.g., total transmission system loading ("TTSL") vs. network transmission billing factors ("NTBF"), firm vs. non-firm, long term vs. short term). Nevertheless, the undeniable conclusion from BPA's numerous performances of the FERC tests is that BPA has a 12 CP system, and has had a 12 CP system since at least 2006 (the earliest year for which BPA performed the FERC tests in this COSA process).[6] As shown in the table below, this was true irrespective of which of the varying assumptions or data BPA or customers identified was actually used in the calculations.

	Test No. 1	**Test No. 2**	**Test No. 3**
Analysis for 12/5/2011 Workshop - using TTSL - Avg. result over 5 Years (2006-2010)[7]	13%	75%	88%
Analysis for 1/11/2012 Workshop - using NTBF - Avg. over result 5 Years (2006-2010)[8]	10%	84%	91%
Analysis for 2/8/2012 Workshop - using TTSL - Avg. result over 6 years (2006-2011)[9]	13%	77%	88%
Analysis for 2/8/2012 Workshop - using Long-Term NTBF - Avg. result over 6 years (2006-2011)[10]	7%	90%	94%
12 CP Condition under FERC Test	**≤ 19%**	**≥ 66%**	**≥ 81%**

[5] *Golden Spread Electric*, 123 FERC 61,047, 61,249 (2008).

[6] Indeed, BPA's conclusion in 2012 that it has a 12 CP system is fully consistent with a conclusion it reached as part of an August 16, 2006 Transmission Rate Case Workshop, which was based on data extending back as far as 1999, i.e., "TBL's transmission loading pattern would support the use of a 12CP divisor for allocating costs between the network rate classes." BPA Transmission Rate Case Workshop Handout, RE: Network Cost Allocation, dated August 16, 2006 and available upon request.

[7] Transmission Cost of Service Analysis Workshop Power Point Presentation, December 5, 2011, available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Workshop_12-05-11_revised.pdf. The numbers in the table are averages over five years (2006-2010) or six years (2006-2011). However, in every case the individual calculations for each specific year also indicated that BPA has a 12 CP system without exception.

[8] FERC Coincidental Peak Test Power Point, January 11, 2012, p. 2, available at http://www.bpa.gov/corporate/ratecase/docs/FERC_Coincidental_Peak_Test.pdf.

[9] Transmission Cost of Service Analysis Workshop Power Point, February 8, 2012, p. 16, available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Workshop_2-8-12.pdf ("Feb. 8th Power Point").

[10] *Id.* at 18.

BPA staff has indicated that the basic principle enunciated by FERC staff in their discussions was that cost allocation should be based primarily on a utility's system planning.[11] This principle is consistent with FERC's justification for using 12 CP allocation methodology, i.e., because "the majority of utilities plan their system to meet their twelve monthly peaks."[12]

BPA adds transmission facilities to its transmission system to meet two primary purposes: reliability and capacity expansion.[13] With respect to reliability planning, FERC's assumption that utilities plan their systems to meet their twelve monthly peaks is also true for BPA. 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 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.[14] Under FERC's approach for cost allocation this type of annual system planning, in addition to the results of the peak demand tests, indicates that BPA should be using a 12 CP allocation methodology.

C. Expansion of the System to Accommodate Resource Development by PTP Customers Warrants BPA's Use of 12 CP.

In addition to reliability, the other chief driver that causes BPA to add transmission facilities is capacity expansion.[15] In 2012 BPA expects to expend a little less than $500 million on transmission capital projects.[16] It expects to spend approximately $550 million more on transmission capital projects in 2013 and another $500+ million in 2014.[17]

Given the above, BPA is projecting an 11 percent rate increase for all Network customers in BP-14.[18] No small portion of this increase stems from BPA's Network Open Season ("NOS") process which primarily serves to expand the Network segment to accommodate non-federal resource development by PTP customers. These costs include:

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[11] *Id.* at 6.

[12] Order 888, 61 FR at 21599.

[13] Feb. 8th Power Point, p. 13.

[14] *Id.* at 9-13.

[15] *Id.* at 13.

[16] Building the Framework for the Integrated Program Review Power Point, January 31, 2012, p. 32, available at http://www.bpa.gov/corporate/pubs/letters/IPR_General-Manager-Meeting.pdf.

[17] *Id.*

[18] *Id.* at 29 (Absent a change to BPA's allocation methodology).

- Repayment of Large Generation Interconnection Agreement (LGIA) Credits;
- Precedent Transmission Service Agreement ("PTSA") Deferrals;
- Increased debt service; and
- Reduction of federal borrowing authority available for other projects.[19]

In addition to the increasing rate pressure, BPA's expansion of the system to bring these new resources online has created a substantial, real risk that BPA will not be able to recover all of the costs of that expansion from the developers that caused them. This is because many of the developers who originally entered into PTSAs with BPA under BPA's NOS process no longer want the transmission capacity. Since many of those parties are judgment proof, single project limited liability companies, in the event of default BPA will ultimately recover the costs created by those developers from its remaining Network customers, both PTP and NT.

All of BPA's customer who use the Network segment share in the costs and risks associated with the NOS projects. However, BPA's use of 1 CP means that its NT customers are shouldering a larger share of those costs than they otherwise would under a 12 CP approach. Since BPA is developing and expanding the transmission system primarily to meet the needs of PTP customers, it is only appropriate that it remedy the imbalance between its move towards FERC's *pro forma* terms and conditions of service and its currents cost allocation methodology by adopting the 12 CP allocation methodology. This will give NT customers some relief from these expansion costs that they did not cause, but would not give them any more relief than they already would have if BPA had followed the FERC approach in the first instance.

D. The Robust Secondary Capacity Market on BPA's System Justifies 12 CP.

FERC has found that allowing holders of firm transmission capacity the right to reassign capacity helps them manage the financial risks associated with their long term commitments, reduces the market power of transmission providers by allowing customers to compete, and fosters efficient capacity allocation.[20] BPA's transmission system is unique in that it has realized FERC's vision for a robust secondary market like none other in the country. According to a 2010 report by FERC staff, in 2009 there were 26,442 capacity reassignment transactions on BPA's system.[21] This accounted for approximately 79 percent of all such transactions nationwide.[22]

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[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).

[20] Order No. 888, 61 FR at 21575-21576.

[21] 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").

[22] *Id.*

The vibrancy of the secondary PTP market on BPA's system highlights a key difference between the PTP and NT products: Whereas BPA's PTP customers can reassign their firm capacity; BPA's NT customers cannot use or reassign unused capacity during off-peak hours.[23] This means that while PTP customers have a means to ameliorate the costs of the PTP product, NT customers do not. Instead, during off-peak hours, BPA sells the unused NT capacity on either the short term firm or non-firm hourly markets. The revenues received from these sales are used to lower the rates of all Network segment customers, both NT and PTP, when BPA calculates firm Network segment rates.

Under FERC's *pro forma* OATT, the inability of NT customers to assign or sell their unused transmission capacity, and the benefit all Network segment customers receive from the resale of unused NT capacity, is balanced by the use of a 12 CP allocation methodology.[24] Consistent with the FERC *pro forma,* BPA has now provided a vibrant secondary capacity market that allows PTP customers to take full advantage of their reassignment rights. Accordingly, the time is now ripe for BPA to likewise provide NT customers the corresponding benefit they are entitled to under the *pro forma* tariff – cost allocation under a 12 CP methodology.

E. A 12 CP Allocation Methodology is Consistent with the COSA Principles.

Finally, the NT Customers' proposal that BPA adopt a 12 CP allocation methodology meets the COSA principles identified by BPA and transmission customers at the beginning of the COSA process:

- 12 CP is consistent with BPA's statutes in that it would ensure cost recovery and allocate the costs of the Network segment equitably between federal and non-federal users of the system.

- 12 CP allocates costs to customers based on their proportionate use in accordance with accepted industry practice for wholesale transmission services.

- 12 CP is simple, administrable, understandable, publicly accepted, feasible in application, durable and repeatable.

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

[24] 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.").

- 12 CP would ensure rate stability from rate period to rate period both in regard to the level of rates and the rate design to be implemented.

- NT Customers have demonstrated a need for change from a 1 CP to a 12 CP methodology.

The one principle that the NT Customers offer no opinion on at this time is whether adoption of a 12 CP methodology would be consistent with the principle of avoiding rate shock. Per the Scope of COSA Process adopted by BPA at the February 8, 2012 Workshop, the final rate development step, rate design, is outside the scope of the COSA process.[25] This means that BPA and customers are to reserve arguments on the issue of avoidance of rate shock until the rate case.

F. Conclusion.

The NT Customers' proposal to use a 12 CP allocation methodology in the COSA is not novel; instead it is a logical extension of BPA's decision to better align itself with FERC policy. Adoption of 12 CP would mean that the terms and conditions of BPA's transmission services and the allocation of costs between such services would both be consistent with FERC policy. In addition, the move to 12 CP would recognize the changing conditions on BPA's system with respect to the expansion of the Network to accommodate resources rather than load and the vigorous secondary capacity market on BPA's system. And, that these changing conditions primarily benefit PTP customers with little benefit to NT customers. Under such circumstances, it is a modest request that BPA bring its cost allocation methodology in line with FERC practice by adopting a 12 CP methodology.

[25] Scope of COSA Process, available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Scope.pdf.