April 24, 2012

Via Electronic Submission
Bonneville Power Administration
techforum@bpa.gov

Re: Comments of Point to Point Customers Coalition, Avista Corp, & Puget Sound Energy, Inc to Bonneville Power Administration's April 12, 2012 COSA Workshop

The Point to Point Customers Coalition ("Coalition")[1] thanks BPA staff for the continued discussions and workshops on BPA's cost of providing transmission service to different customer classes. After reading the comments filed on March 30 and listening to the discussion, we remain convinced that the 1NCD method is the most appropriate approach for allocating network costs. As a result of the workshops, we have a much greater understanding of BPA's cost of service analysis process – from the revenue requirements model to segmentation and rates. We continue to have questions and concerns about how costs are allocated to the Network segment. We are concerned that PTP customers (as well as NT customers in some cases) are being allocated costs for services they neither cause nor benefit from.

I. Allocation of Costs *Within* the Network Segment

BPA will have a heavy lift to show why the situation has changed since 1996, when the agency considered a variety of approaches (12CP and 1CP among them) and concluded that 1NCD was superior. BPA stated in its 1996 reciprocity petition for declaratory order that:

> It is appropriate to use the one-noncoincidental demand method for the load-based NT service because it most closely resembles the contract demands used to assign costs to other classes, and it reflects how BPA plans its transmission system. BPA planning studies look at a winter condition with loads equal to the sum of the utilities' annual noncoincidental demands. BPA also plans for a summer peak on the parts of the FCRTS where peak loading conditions occur in the summer []. This cost allocation approach was agreed to by the parties in the Transmission Settlement.[2]

We have seen no evidence to support a departure from this conclusion.

As for the claim that 12CP is FERC's preferred method, FERC determines cost allocation on a case-by-case basis. There is no "one size fits all" cost allocation methodology. FERC has

[1] The Coalition includes Benton County Public Utility District No. 1, EDP Renewables, Franklin County Public Utility District No. 1, M-S-R Public Power Agency, Pend Oreille Public Utility District No. 1, Powerex, Seattle City Light, Snohomish County Public Utility District No. 1, and Tacoma Power.

[2] *Bonneville Power Administration's Petition for Declaratory Order Regarding Rates for Open Access Transmission Service and an Exemption in Lieu of the Application Fee*, Docket No. NJ97-3-000, p. 29 (December 20, 1996).

recognized that alternative allocation proposals may have merit and welcomes them.[3] In Order No. 888. FERC reaffirmed the use of the 12CP method only because it believed the majority of utilities planned their systems to meet their twelve monthly peaks.[4] As was the case in 1996, and is the case now, BPA does not plan its system to meet its twelve monthly peaks.

As indicated in comments submitted on March 30, the NT MOA provides the only other reasonable alternative approach for achieving equivalency between PTP contract demands and NT usage. The NT MOA designates 65% of the Federal Columbia River Power System (FCRPS) for NT service. BPA's White Book identifies the operational peaking capacity of the federal system as 16,573 MW.[5] Multiplying this by 65% produces a figure of 10,772.45 MW, which would provide a comparable "Reserved Capacity" figure for NT service.[6]

II. Allocation of Costs *to* the Network Segment

One of our primary concerns is the degree to which costs are allocated to the network segment or directly assigned to specific groups of customers benefiting from services. We would like to explore certain decision criteria and input data more carefully.

a) Reimbursable Expenses. We would like to gain a clearer understanding of the two types of reimbursable expenses – those that are forecasted and included in the transmission revenue requirement and those that are excluded. How is the choice made to exclude versus include certain reimbursables? What impact, if any, does this choice have on the ultimate rates to customers?

b) Corporate Overhead. We understand that Corporate Services costs were previously allocated equally between power and transmission. The COSA analysis indicates a shift to an allocation of 35% to power and 65% to transmission. What is the basis for this change? Also, we understand that activities associated with NERC compliance assistance are housed in BPA's Corporate Division. How are these costs tied to the customers/utilities that benefit from the services?

c) Direct Assignments. We ask that BPA review costs that are directly assigned costs in the current Transmission COSA models. We would like to understand how costs are identified for direct assignment.

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[3] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,736 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[4] *Id.*

[5] See Table 3. "Total Federal Firm Resources" under a 1-Hour Operational Peaking Capacity, January http://www.bpa.gov/power/pgp/whitebook/2011/WhiteBook2011_SummaryDocument_Final.pdf (electronic page 29).

[6] At the April 12, 2012 COSA meeting, BPA staff committed to providing data that would support the MOA and specifically, the nameplate capacities associated with resources contained in Exhibit A.

d) Demarcation of Utility Delivery Segment. Again, we would like to understand how the current 34.5 KV demarcation between the Utility Delivery and Network Segments was established. In Order No. 888, FERC set out seven indicators, a combination of functional and technical tests, to assist companies and state commissions with separating local distribution facilities from FERC-jurisdictional transmission facilities on a case-by-case basis.[7] The current NERC definition for bulk electric system includes a 100 kV bright line standard. We would like to see how these alternative definitions would affect costs allocated to the Network segment.

III. Workshop Schedule

We have reviewed the Proposed BP-14 Transmission Rate Case Workshop Schedule and believe it is appropriate. We would anticipate exploring:

- Reimbursable, corporate overhead and direct assignments on May 23 as part of the Segmentation discussion.
- Demarcation of Utility Delivery Segment on June 13 as part of the Utility Delivery discussion.

IV. COSA Model

We appreciate BPA's collaborative effort in sharing its suite of transmission COSA models (Green Book). We found the models to be straightforward and the analysis fundamentally appropriate. The collection of these models along with the effort put forth by BPA staff have provided us with a much more comprehensive understanding of the transmission rates. We ask that BPA further explore the areas of concern identified above as they may impact some of the calculations.

V. Completion of Settlement Obligations

Following completion of the workshops currently scheduled, we believe BPA will have met its obligations under the Settlement Agreement. As required by the Settlement Agreement, BPA has:

(a) worked with interested transmission customers in an open and collaborative forum to define the parameters of a cost of service study that includes consideration of alternative methodologies for allocating demand-related costs and that determines the costs of BPA's major transmission services;

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[7] The seven factors are as follows: (1) Local distribution facilities are normally in close proximity to retail customers; (2) Local distribution facilities are primarily radial in character; (3) Power flows into local distribution systems; it rarely, if ever, flows out; (4) When power enters a local distribution system, it is not reconsigned or transported on to some other market; (5) Power entering a local distribution system is consumed in a comparatively restricted geographical area; (6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system; and (7) Local distribution systems will be of reduced voltage. *See* Order No. 888 at 31,771.

(b) completed an illustrative cost of service study using forecasted data from a recent fiscal year; and

(c) shared the cost of service model with customers to ensure clear and transparent cost of service determinations.

Again, we thank the BPA staff for its effort in making the workshops productive and informative. We look forward to the final set of workshops and to participating fully in the upcoming rate case.[8]

Sincerely,

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On behalf of the

Point to Point Customers Coalition,
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Puget Sound Energy, Inc.

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[8] 2012 Wholesale Power and Transmission Rate Adjustment Proceeding (BP-12), Administrator's Final Record of Decision, Appendix A: Partial Transmission Settlement Agreement at § 6 (July 2011) (emphasis added).