Regional White Paper
Segmentation Methodology Alternatives

May 29, 2014

Table of Contents

I. Introduction

The objective of this white paper is to capture the regional discussion that BPA and customers have had as a precursor to the BP-16 rate case. The regional discussion has focused on whether or not BPA should adopt an alternative segmentation methodology from that used in BP-14 in its initial proposal for BP-16.

II. Background

What is segmentation?

Segmentation is a part of BPA's cost allocation process in determining transmission rates. The Segmentation Study associates specific transmission facilities (lines, substations, general plant, communications, other equipment) into defined groups, called segments. The current practice identifies and aggregates costs into seven segments. Once each facility is associated with one or more segments, the total investment and historical O&M for each segment is calculated. The total investment and O&M for each segment becomes an allocation factor to distribute the rate period transmission revenue requirement across the segments: Investment is used to distribute rate period depreciation and debt service costs, and historical O&M is used to distribute rate period O&M costs. The costs assigned to each segment are then used to set the various rates for the use of each segment.

The origins of segmentation

From BPA's origins, transmission costs were bundled together with power costs and recovered through rates for power sold by BPA. Occasionally, another utility would contract with BPA to wheel non-federal power across BPA's transmission system. BPA established rates for these uses through separate contracts. As the amount of wheeling on BPA's system grew, the rates for this service became more standardized. Generally, most wheeling was charged based on the specific types of facilities used for each transaction: the number of terminals on the contract path, the number of miles between the receipt point and the delivery point, transformation between 230/500kV and 115kV, and, when called for by contract, the southern intertie. The revenues from the wheeling contracts were credited against BPA's system costs to lower the bundled rates for power sold by BPA.

The Federal Columbia River Transmission System Act, 16 U.S.C. § 838 *et seq.*, provided that the BPA Administrator "make available to all utilities on a fair and nondiscriminatory basis, any capacity in the Federal transmission system which he determines to be in excess of the capacity required to transmit electric power generated or acquired by the United States." It also provided that "the recovery of the cost of the Federal transmission system shall be equitably allocated between Federal and non Federal power utilizing such system." Shortly after enactment, BPA filed its first transmission rates (the Formula Power Transmission (FPT) rates were exclusively for wheeling non-federal power; BPA did not file new bundled power rates). These rates were filed with the Federal Power Commission, which was reorganized as the Federal Energy Regulatory Commission (Commission) the next year. Four years after the filing, in December 1980, the Commission remanded the rates to BPA without prejudice. The Commission requested that BPA demonstrate: 1) a rational basis for the determination of the annual cost of the transmission system; 2) a rational basis for the determination that the annual costs of the transmission system had been equitably allocated between Federal and non-Federal system users; and 3) a

justification and ratemaking rationale to support the use of airline mileage billing determinants in the FPT-1 rates, as contrasted to circuit mile cost supported type rates. In addition, an explanation, including calculations, of how the revenue figures were derived in support of the proposed rate schedules was requested.

Prior to the remand order, the Commission had alerted BPA to some of the problems it was having with the transmission rates. This allowed BPA, in its 1979 power rate case, to develop more supporting information with respect to the transmission costs included in bundled power rates. BPA developed its first segmentation methodology in this case to demonstrate that power rates were recovering its appropriate share of transmission costs.

Segmentation was first applied for transmission rates in the 1981 rate case. In that case, one segmentation issue was addressed by the Commission: that BPA failed to properly segment those portions of the transmission facilities above 69kV that only serve the load of Direct Service Industrial customers (DSIs). The Commission found that BPA expected these lines to be extended to serve other substations and customers in the future. Accordingly, to assign the total cost of these lines to the delivery segment of an existing DSI would result in an inequitable overallocation of costs to the DSI service class and would distort the appropriate allocation between Federal and non-Federal transmission users.

Between 1979 and 1996, segmentation was used to establish the Network facilities and associated costs, Intertie facilities and costs, and other segment facilities and costs. Intertie costs were recovered through BPA power and wheeling uses of the Intertie segments. BPA's Network transmission costs were recovered through a combination of bundled power rates and wheeling rates, both based on a 12CP share of Network costs based on usage. All other facilities were assigned to the Fringe or three Delivery segments. The Fringe segment was comprised of facilities that were generally similar to Network facilities, but used solely for federal power; the distinctions between Fringe and Delivery facilities was, at times, inconsistent; however, this had little effect on rates—all of the costs of these other segments were recovered through bundled power rates.

Beginning in 1996, BPA's power and transmission costs were unbundled: each power customer paid separate power and transmission rates, and transmission rates were no longer distinguished between application to federal and non-federal. In the 1996 rate case, staff proposed to roll the Fringe into the Network along with a portion of Delivery facilities. Delivery facilities at or below 34.5kV were proposed to be separately assigned to delivery rates. BPA's initial proposal was hotly debated; in particular, IOUs disputed the roll in of the Fringe, and various parties disputed using 34.5kV as the threshold for the Network. Ultimately, the case settled. The major segmentation-related elements of the settlement were that power rates would pay for transfer agreement costs, the Network would consist of non-Intertie facilities that were 34.5kV and higher (with no Fringe Segment), the Northern Intertie would be rolled into the Network, BPA would endeavor to sell Delivery facilities (defined as facilities below 34.5kV) to the local utilities to allow them to avoid the Delivery rate, the NT rate would have a Load Shaping charge to account for peak usage, and the then-current Customer Service Policy for the allocation of costs of new transmission facilities would be replaced with a policy that conformed with open access principles.

Since 1996, all BPA transmission rate cases were settled until the BP-14 case. None of the settled rate cases changed the settlement-based segmentation. In the BP-14 rate case, staff proposed to continue the same segmentation methodology established by and used since the 1996 settlement.

Although the facility and associated cost analysis was updated, the definitions and criteria of the segments were not. These definitions and criteria became a major issue in the BP-14 rate case with various parties disputing or defending the proposed segmentation. The primary issue was the definition of the Integrated Network segment. The issue of rolling the Fringe into the Integrated Network was renewed. The use of the 34.5kV threshold was questioned: an alternative 116kV threshold was proposed, as was assigning lower voltage costs to the utilities using facilities below that threshold. Others defended the current segmentation methodology as conforming to statutory provisions for widespread use and BPA's application of uniform rates. In addition, the question of maintaining the Montana Intertie rate, a rate based on the Eastern Intertie segment, was raised.

Positions in BP-14

As part of the 2014 rate case, certain parties raised a broad range of issues about BPA's transmission segmentation policy, primarily about the use of a bright-line 34.5kV voltage threshold to separate facilities between the Integrated Network and Utility Delivery segments. This threshold results in facilities 34.5kV and above being assigned to BPA's Network segment. Facilities that fall below the 34.5kV threshold are assigned to the Utility Delivery segment. This threshold originated in the non-precedential 1996 rate case settlement and had been perpetuated through subsequent rate settlements (the settlements mooted any issues regarding the threshold until BP-14).

Also resulting from the 1996 rate case settlement, BPA implemented a policy of selling utility delivery facilities (transmission facilities below 34.5kV) to customers using those facilities. Purchasing delivery facilities allowed customers to avoid a pancaked rate (paying both Network and Utility delivery rates) and significantly reduced BPA's investment in low voltage facilities. Currently, BPA has sold 170 of the 215 low voltage delivery facilities and retired others. The remaining facilities are included in the Utility Delivery segment. The Utility Delivery Charge (UDC) currently does not recover the full cost of the Utility Delivery segment. In the last rate case BPA proposed to increase the UDC by 25% for the next two rate periods, then adopt a UFT charge for remaining unsold facilities (which gradually reduces and eventually eliminates the under recovery). Setting the UDC to recover the full costs of the segment would have required an immediate UDC increase of over 100%. .

BPA identified several difficult issues that would have to be addressed if it were to deviate from the current Delivery segment definition. First, moving higher voltages into the Utility Delivery segment could cause many customers that purchased facilities to avoid a pancaked rate to again be required to pay two rates. Second, rolling the Utility Delivery segment into the Network could cause customers that purchased delivery facilities to avoid the pancaked rate to believe they were misled because other customers who did not take on the additional cost and responsibility of owning similar facilities would no longer pay a pancaked rate. Third, applying a functional definition rather than a bright-line voltage threshold would lead to many difficult and disputed decisions. Fourth, while alternative segmentation methodologies were proposed, there were no proposals about how to recover costs from customers affected by alternative segmentations. While these were among issues that must be resolved, customers proposing changes to segmentation did not address them in their BP-14 testimony. Furthermore, BPA's agreement with transfer customers states that transfer costs and rates will mirror the segmentation of BPA's transmission system. Thus, changes in segmentation may result in changes to Power costs and rates.

In BP-14 testimony, staff cited the importance of rolled in rates both in FERC policy and in BPA's history, arguments which were offered in support of the proposal to maintain the voltage threshold of 34.5kV. Staff cited several cases that showed FERC's preference for rolled in rates when any amount of integration is shown on the facilities. Staff also recalled some of the main reasons the Bonneville Power Administration was formed: to encourage the widespread use of electric power in the Northwest and to assist rural electrification. BPA staff suggested that this guidance and historical precedent was inconsistent with customers' proposals to change the threshold to a level higher than 34.5 kV. The larger customers responded that rural areas are now, and have been for a long time, electrified; BPA's policies should recognize this and begin to move towards more rational cost assignments.

In the BP-14 proceedings, some customers cited two specific functional analyses that have resulted from FERC orders and rulings. These customers suggested that such tests should be used to define what facilities should be included in BPA's Integrated Network segment. The first test referenced is the Seven Factor Test, which FERC introduced in Order 888. This test is primarily used by jurisdictional utilities to determine whether a facility is performing a transmission function (subject to FERC jurisdiction) or distribution function (subject to state jurisdiction). If a facility meets the criteria (see appendix) it is deemed to be a local distribution facility; thus, it is subject to state PUC jurisdiction, not FERC jurisdiction. If a facility meets some factors but not all, the factors must be weighed against each other to determine the function of the facility. Other customers pointed out that the Seven Factor test was conditioned on the lack of wholesale activity using the facility; if there was wholesale activity present, FERC retained jurisdiction. Staff noted that all uses of BPA Network transmission facilities are used for wholesale activities. In recent years, FERC has begun using the Seven Factor Test as a consideration in transmission ratemaking.

The other functional test that customers referenced in their argument after the evidentiary phase of the BP-14 proceeding closed is the *Mansfield* Five Factor Test (see appendix for detail). This test was developed in a FERC case, *Mansfield v. New England ISO*. The Five Factor test is used to determine whether facilities costs should be rolled into Network rates or directly assigned to the customer that uses the facility for service to its load. (The city of Mansfield challenged NE-ISO lumping facilities used by Mansfield into a larger group of similar facilities used to serve other cities; Mansfield's facilities were more limited and cheaper than the facilities for others. FERC sided with Mansfield by directing NE-ISO to charge Mansfield for just the facilities used to serve Mansfield.) While the Seven Factor Test relies on a weighting of the various factors to determine if a facility performs a transmission function, the *Mansfield* test requires that all five factors be met to show that the main purpose is customer-specific delivery and the costs of that facility be directly assigned to the customer. BPA's current methodology for deciding between Network v. Direct assignment is to use an integration test which is not exactly the same as the Mansfield test, but relies on some of the same principles (the *Mansfield* and subsequent FERC decisions are considered in directly assigning costs). This issue was not explored in testimony, so the arguments made in BP-14 concerning potential application of the Mansfield test to BPA facilities were not based on any evidence in the record.

In BP-14, some customers cited NERC's Bulk Electric System (BES) definition of transmission and local distribution and argued that BPA should make its definition of the Integrated Network consistent with the BES definition. NERC currently defines the BES as any facilities operated at or above 100kV with exclusions for radial systems, local networks, generating units on the customer's side of a

retail meter, and reactive power devices owned and operated by a retail customer for their own use. (This definition continues to undergo FERC and NERC review.) NERC's purpose for defining the BES is to determine which facilities are critical to the reliability of the grid. NERC developed extensive reliability standards and reporting requirements for BES facilities, and they monitor compliance. Customers arguing for the use of the BES definition also argued that the BPA application of the threshold should be raised to 116kV. No FERC cases have been found to indicate the use of the 100kV BES definition as a method for setting rates. Instead, excluding a high number of facilities using this method seems at odds with FERC's demonstrated "roll in" preference. Furthermore, the BES definition has no mention of state-versus-federal jurisdiction, nor does it mention wholesale activity.

There were four main reasons staff gave for not performing a detailed functional analysis of BPA's transmission facilities for BP-14 rates. First, there were several unanswered questions that were not addressed in parties' testimony, including proposals for how costs that were formerly assigned to the Network would be recovered under an alternative methodology (e.g., direct assignment, a new segment and rate, etc.). Second, staff reviewed the composition of facilities in the Network and Delivery segments, as modified since 1996, and determined that the 34.5kV threshold was still appropriate to recognize facilities performing a transmission rather than delivery function. Additionally, staff noted that if it were to perform a functional analysis it was not clear which criteria should be used and it is also uncertain if the FERC tests are appropriate for BPA ratemaking purposes. The most important reason staff gave in the BP-14 case for not pursuing a functional analysis was that rolling in facilities to promote the widest use is consistent with FERC case law and orders, and promoting rural electrification is a founding principle for BPA itself. FERC has ruled in multiple cases that if there is any amount of integration, then a facility should be included in rolled in Network rates. A review of FERC cases shows FERC leans towards a system in which any facilities that are performing a transmission function or are integrated into the network transmission system should be rolled into the Network costs and charged a rate consistent with other facilities operating in a similar manner at other voltages. In staff's benchmarking analysis (performed after the 2014 case—see Industry Scan below), only two non-RTO/ISO entities have been identified as having a "sub-transmission" segment and one of those rates is being challenged at FERC. The Transmission Owner is defending their sub-transmission rate, in part, by specifying that the cost of the "sub-transmission" is rolled in – it is just rolled into a different rate than the high voltage network facilities. In addition, most utilities included in the scan have only looked at changing policies going forward and do not redefine assets previously included in definition of Network or other segments unless there are physical modifications of those facilities.

BPA's historical mandate to help with rural electrification is consistent with BPA rolling lower voltage facilities into the Network. A review of most of the 34.5 kV facilities indicated that all of these lower voltage facilities are performing a transmission function, but doing so in rural areas where lower loads lead to using lower voltage infrastructure to keep costs down. Charging customers an additional sub-transmission rate may be inconsistent with BPA's mandate to facilitate widespread use and rural electrification. In BP-14 BPA argued that the proposed change would punish some rural customers for being located in areas where lower voltages are sufficient to support transmission to their service territories.

BPA stood behind these reasons to justify maintaining the 34.5 kV threshold in BP-14, but did include language in its ROD that "[b]efore the next rate proceeding BPA will engage the region regarding

segmentation policy. Staff and interested stakeholders should work together at the outset of these discussions to identify the framework and agenda for these discussions." This white paper is the fruit of those discussions.

Regional Discussion Prior to BP-16

To meet the commitment set forth in the BP-14 ROD, a regional discussion on Segmentation hosted by BPA kicked off in January 2014. In the first meetings BPA staff worked with its customers (both at the General Management and staff level) to educate them on the issue of segmentation. This effort included sharing information on BPA's current segmentation and direct assignment practices as well as BPA's findings from an industry scan conducted on FERC-jurisdictional transmission providers throughout the country.

Industry Scan

Based on the issues discussed in the BP-14 rate case, staff developed three basic questions to be answered by the industry scan:

1. How comparable to BPA are the other utilities' transmission facilities in size and voltage?

   BPA has over 15,000 line miles of transmission; reviewing the size of BPA in comparison with other TPs helped define the scope of the review and gave additional context to the challenges that an entity the size of BPA faces. Adding BPA to the 181 utilities reviewed, BPA would rank fourth in terms of transmission line miles. The inclusion of TVA and the other two PMAs to the list would move BPA to sixth of 185 utilities. It was concluded that including utilities with small or no transmission would not add much value to the exercise, and focusing on 100 utilities would comprise a representative pool of utilities. The 100th utility had 626 line miles, and moving the line to 500 miles would pick up two others, including Consolidated Edison, one of the largest utilities in the nation. Thus, a cutoff at 500 miles was used for this scan. Of the utilities excluded, 20 have between 100 and 500 miles of transmission lines, 23 have between 1 and 100 miles, and 35 have no transmission lines, including 6 RTO/ISO companies and 10 that have sold or spun off all of their transmission facilities into independent transmission companies.

2. What, if any, voltage threshold do other utilities use to separate transmission from distribution?

The table below shows BPA's staff finding from review of Form 1 submittals.

Count of Utilities	115kV	69kV	46kV	35kV	25kV
Transmission	96	82	45	30	13
Likely Transmission	1	3	6	7	4
Either	1	3	5	11	3
Likely Distribution	0	3	2	8	9
Distribution	0	3	10	29	52
Indeterminate	4	8	34	17	21
Total Population	102	102	102	102	102

Tx Probability	99%	92%	79%	50%	23%

The 35kV (the threshold used by BPA in BP-14) column of the table shows that 30 of 102 utilities include all of their 35kV facilities in transmission, 7 include most of their 35kV facilities in transmission, 11 include about half of their 35kV facilities in transmission, 8 include most of their 35kV facilities in distribution, 29 include all of their 35kV facilities in distribution, and 17 cannot be determined (these utilities have no facilities at voltages between those designated transmission and those designated distribution, e.g., 46kV is transmission and 25kV is distribution and there are no 35kV facilities). The probability that any specific 35kV facility would be designated as transmission is about 50 percent ([30+7+½ of 11] ÷ [102 –17] = 50%). The use of this threshold is reinforced by a statement by the Commission in its legal analysis of Order 888: "while there is no uniform breakout point between transmission and distribution, it appears that utilities account for facilities operated at greater than 30kV as transmission and that distribution facilities are usually less than 40kV." Order No. 888, Appendix G, FERC STATS. & REGS. ¶ 31,036 at 31,981 n.100. Thus while FERC does say that there is no specific threshold that should be used, BPA's BP-14 voltage threshold dividing "Network" facilities from "Delivery" facilities is consistent with the median observed in the study.

3. Do the utilities differentiate transmission rates by voltage or other criteria?

Staff found that 66 utilities roll all transmission facilities into their network rates (Point-to-Point and Network Integration), 35 utilities differentiate their network transmission rates into bulk system rates and sub-transmission rates based on a voltage basis. Table x in the appendix lists the 35 utilities with a brief description of the rate design (most of these 35 utilities differentiate based on ISO/RTOs requirements, which comprise eight separate entities). Six utilities have facility-differentiated transmission rates, usually due to interties connecting their systems to other areas.

Information on treatment of radial lines was gathered through discussions with select utilities since treatment of such lines is not clear in Form 1 data. In these discussions, BPA found that the entities interviewed had significantly different practices:

- Duke Energy is in the process of revising its treatment of radial lines. In the past, Duke would roll in the cost of its radial lines into its network transmission rates and would use network credits to compensate a customer that constructed a radial line between Duke's network and the customer's load. Duke's new policy would directly assign its radial lines and would not give credits to customers for radial lines. Duke Carolinas implemented this treatment several years ago; Duke Progress began implementing this policy in January 2014. In both cases, the policy is not retroactive—Duke did not remove its radials from its network rates and continues applying credits for customer-owned facilities built prior to the new treatment.
- The Southern Company directly assigns radial lines that are serving only wholesale or only retail functions to the user of such lines. Radial lines with mixed usage (both retail and wholesale customers) are included in the network. Southern's wheeling customers challenged their old Direct Assignment policy, which included some retail function radials in the Network. Their customers argued this was not providing customers

comparable treatment . Southern settled the dispute and changed its policy. Pursuant to the settlement, radial lines constructed between 2003-2010 were removed from the Network segment.

- Southern California Edison and Pacific Gas & Electric generally assign radial wholesale lines to the customer served from the radial. In 2004 Edison changed its direct assignment policy for some breakers based on a Commission ruling. Edison now includes in the Network the costs associated with ring breakers to integrate generation. Previously these costs were directly assigned to the integrating party ; Edison did not retroactively apply this change, but applies the new practice whenever new equipment is added to an older station.
- Members of the Southwest Power Pool are required to remove single-customer radial lines from the costs submitted for inclusion in SPP bulk system transmission rates.

After sharing this preliminary information, BPA asked participants to develop proposals for alternative Segmentation methodologies for analysis. BPA has performed analysis on 6 proposals received (5 for Network alternatives and 1 for Montana Intertie) as well as the status quo. These proposals and associated analyses are discussed in Section III of this paper.

BPA's Segmentation Principles:

BPA staff, with executive input, developed principles for the segmentation analysis which will be used to evaluate each of the proposals. These principles were shared with customers and reflect some customer input.

1. Consistent with statutory requirements
a. Full and timely cost recovery
b. BPA's rates are based on total system costs
c. Equitable cost allocation between federal and non-federal uses of the Transmission system
d. Encourages the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles

2. Consistent with rate making principles
a. Cost causation
b. Simplicity, understandability, public acceptance and feasibility of application
c. Avoidance of rate shock
d. Rate stability from rate period to rate period

3. Considers a regional perspective
a. Alternatives include how costs are allocated and recovered
b. BPA asks that proponents of alternatives explain how the region benefits from the alternative compared to the status quo
c. Historically BPA has applied uniform rates to achieve widest possible diversified use

III. Proposed Alternatives and Analysis

Using the status quo as a benchmark, BPA staff evaluated the proposed alternatives. Participants were asked to include in their segmentation alternatives how transmission system costs would be allocated and recovered under their segmentation. This required customers to identify in their proposals not only the guidelines for changing the segmentation of facilities, but also outlining a rate design for how the segment costs would be recovered from BPA customers. Recognizing that a change in segmentation could introduce rate shock to some customers, participants were asked to identify any rate mitigation strategies that might be appropriate.

All analysis shown in this paper is based on BP-14 Final Proposal revenue requirement and forecast sales and is "decision quality" analysis. When BPA performs the segmentation analysis for the BP-16 case, the best data available for FY 2016 and FY 2017 will be used, applying the decision resulting from this white paper. In addition, for alternatives where simplification was used for discussion purposes (i.e. Revenue Requirement "Rule of Thumb"), this will be replaced by a full treatment of data through BPA's repayment, revenue requirement, and rates models for the Initial Proposal. Thus, for the alternative chosen for the initial proposal in BP-16, the results in BP-16 will likely differ somewhat from the analysis of that alternative contained here.

Network Segment Alternatives

Network Alternative 1 – Status Quo

BPA transmission rates methodology currently identifies and collects costs from seven segments: Generation Integration, Integrated Network, Southern Intertie, Eastern Intertie, Utility Delivery, Direct Service Industry (DSI) Delivery, and Ancillary Services. The BP-14 Final Proposal documentation contains information on how these numbers were developed.

The status quo is offered as a viable alternative for consideration in this process. The fact that BPA is undertaking a review of its segmentation alternative does not mean that BPA must or should change its segmentation methodology. However, because the status quo alternative was generated from a non-precedential rate settlement, the status quo should not be considered the presumptive alternative where other alternatives must demonstrate conditions necessitating a change in segmentation. The status quo is offered as an equal among the various alternatives being considered. However, in the analysis of the various alternatives, the status quo is used as a measure of cost shift simply because it is the basis for rates being paid today.

Status Quo Justification

The status quo use of a bright-line voltage threshold at 34.5kV appears to be solidly in the center of the practice that jurisdictional utilities across the country use to distinguish between transmission and distribution.

Network Alternative 2 – Roll In Utility Delivery Segment - Proposed by PNGC

Roll all facilities currently in the Utility Delivery (UD) segment into the Network segment. The UD rate would be eliminated and costs associated with former UD facilities are recovered through the Network rates.

PNGC Justification

BPA instituted the UD Charge (UDC) in 1997 in part to incent customers to purchase the wholesale substations that BPA had previously provided. When the UDC was put in place, it was recognized that at some point the UDC would become unsustainable. We have now reached the point of unsustainability, given the number of UD facilities that have been sold, and the costs, billing determinants, and the "unpurchaseable" nature of the remaining UD facilities.

Rolling the UD facilities into the Network segment is consistent with BPA's statutory responsibility to set power and transmission rates that encourage "the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles." (Federal Columbia River Transmission System Act at 16 U.S.C. § 838g).

Doing so will result in minimal rate impact to Network segment transmission rates (approximately 0.6% for the PTP rate and 0.3% for the NT rate), while avoiding an unnecessarily severe impact on transmission rates for those who would otherwise pay the UDC.

Further, the UDC has outlived its original purpose of incenting utilities to purchase the UD facilities. Since the implementation of the UDC, BPA has sold 158 out of 203 of the UD facilities. The remaining 45 substation are not likely to be sold, even if BPA follows through with plans to increase the UD rate 84% over the next several rate cases. There are several reasons that many of the remaining substations are "unpurchaseable" from the utilities' point of view:

- The remaining transformers are very old (average age 58.2 years, with 17 transformers over 70 years old) and customers are wary of purchasing such old equipment, particularly given the possible reliability consequences and costs associated with equipment failure;
- 16 facilities are not segmented 100% to the UD segment, which significantly complicates a possible sale (BPA typically would not sell elements of a multi-segmented substation);
- 14 facilities are shared by multiple customers, which significantly complicates a possible sale;
- Acquisitions of high voltage equipment have potential staffing, training, and reliability implications well beyond the price of the delivery substation; and
- At a time when many small utilities are deregistering from ERO compliance obligations, adding high voltage equipment to their systems could unnecessarily endanger those efforts.

Of the remaining 45 UD substations, 39 face at least one of the above challenges. Many face more than one of these challenges. In short, the vast majority of the remaining substations are "unpurchaseable" no matter how high the UDC goes. Consequently, retaining the UD segment, and increasing the UDC by 25% in the next rate case, will not result in substantial sales of the UD facilities. It will, however, result in a UD rate higher than the current NT transmission rate. At that point, customers subject to the UDC would essentially pay a pancaked transmission rate that amounts to two times the NT rate. We have arrived at the point where the most logical action is to roll the remaining UD facilities into the Network segment.

PNGC Evaluation based on BPA Principles

1. Consistent with Statutory Requirements
   - Roll in would ensure widest possible use at lowest possible rates to consumers consistent with sound business principles
   - Would ensure full and timely cost recovery
   - Rates would be based on system costs
   - Would maintain equitable allocation between federal and non-federal uses

2. Consistent with Ratemaking Principles
   - Cost causation – these facilities were put in as wholesale points of delivery, and are part of system needed to transmit wholesale power to wholesale customers
   - It's simple, understandable, easy to apply, and would be acceptable to many customers
   - Avoids rate shock to all parties
   - Does provide stability, especially vis-à-vis alternatives (scheduled rate increases)

3. Considers a Regional Perspective
   - By fulfilling BPA's statutory directive to provide the widest possible use at the lowest possible cost to consumers, the roll-in alternative promotes an economically healthy rural segment of our region
   - Without a roll-in of the UD segment into the Network segment, many rural areas will pay approximately double for transmission service, thereby negatively impacting economic well-being in these areas; alternatively, rolling-in the UD segment will have minimal impact on the Network segment while avoiding rate shock for the current UD customers
   - Provides level playing field to all sellers of power
   - Retains uniform rates
   - Respects past BPA policies which provided these substations

Network Alternative 3 – Maintain Adjusted Utility Delivery Charge – Proposed by NRU

As part of the BPA Transmission Segmentation review, NRU recommends a fundamental revision in the methodology for determining the Utility Delivery Charge (UDC). The application of the proposed new UDC methodology beginning in FY 2016 would result in a UDC that is generally comparable to the current level in the FY 2014/2015 rates after the 25% increase for delivery service. In this proposal the Utility Delivery segment is eliminated in FY 2016 and beyond, the adjusted revenue requirement is rolled into the Network, and the revenue from the new UDC is credited to the Network Segment revenue requirement. The UDC is applied as a uniform charge to all utilities taking delivery from BPA substations below 34.5 kV.

The proposed NRU staff methodology for deriving a new UDC is illustrated in attachment xxxx. It displays the existing BPA methodology and shows revisions to develop the new charge.

The key components of change are as follows:

- The UDC would include the direct O&M cost of Lines and Substations but would exclude the O&M Overhead charges (see discussion that follows). As a result, the cost recovery for O&M is reduced to about 57% of the current level for the Utility Delivery segment.
- The financial value of the FCRTS Investment Base (Net Plant) of about $21 M for Utility Delivery is reduced to 20% of its current level based on NRU members' assessment of the actual remaining value of the assets. For example, the average age of utility transformers since their date of manufacture is 55 years and 42 years since their installation (new or used). The BPA Depreciation Study in 1984, 1989 and 2004 identifies 37 years as the life of substation equipment. The situation will vary from facility to facility, but generally NRU members believe these facilities are "old" and over-valued.
- Based on the revised 20% value of Utility Delivery Net Plant, the direct depreciation calculation is reduced proportionately. However, we depreciate BPA's General Plant, which supports the delivery of O&M, at 100%. This results in a total depreciation cost of about 49% of the current level.
- This 49% is then applied to the Net Interest Expense and Planned Net Revenue figures because these numbers are a product of the revised net plant investment.
- When the O&M and other costs are combined the Utility Delivery revenue requirement becomes 56% of the current amount, reduced from about $6.4 M to $3.6 M.
- NRU did not adjust the reported Revenue Credits of about $240,000 accruing to the Utility Delivery segment but recognizes that they could change.
- Finally, NRU reduces the level of Transmission financial reserves applied in the BP-14 rate case to offset the UDC, based on a lower overall recommended cost for delivery service.
- When these elements are combined, the UDC recovers the cost of the utility delivery facilities.
- In future rate cases, the UDC would increase commensurate with the average change in rates for PTP and NT Network service (on a percentage basis).

NRU Justification

In the BP-14 rate case, BPA raised the UDC by 25%, from $1.119 kW/Mo. to $1.399 kW/Mo. Using current cost recovery methodologies, BPA identified an under recovery of the Utility Delivery segment, and absent corrective action, this sets the stage for continuing significant UDC increases in the future. This could have a dramatic impact on utilities with delivery facilities. For example, if BPA again increased the UDC by another 25%, the charge for delivery service would essentially be equal to the current $1.741 kW/Mo. charge for Network Transmission. The customers using low voltage delivery facilities effectively would be paying double the NT rate compared to other customers. In contrast to the BPA UDC of $1.399 kW/Mo., the GTA Delivery Charge, which applies to customers that purchase federal power that is delivered over non-federal low voltage facilities operated below 34.5 kV is at a rate of $0.820 kW/Mo. Our understanding is that the GTA Delivery Charge recovers the actual cost for delivery service where such costs are imposed by the GTA provider. The GTA Delivery Charge of $.0820 kW/Mo. is less than 59% of the BPA UDC. While we have not analyzed the financial components of the rate charged by the GTA providers, this raises questions regarding BPA's UDC, and if a revised methodology for BPA cost recovery would result in a more equitable charge for BPA Transmission's Utility Delivery customers.

Rationale for Revisions in O&M Costs

In reviewing the Direct O&M numbers for the Utility Delivery segment substations compared to the Integrated Network Facilities, the differences are quite dramatic. For the Integrated Network, the Substations have a reported investment of $2.182 B and O&M at $85.25 M. O&M activities represent about 3.9% of the investment value for Network Substations. The Utility Delivery Facilities have a reported investment of $29.575 M and O&M at $1.85 M. O&M activities represent about 6.3% of the reported investment value for Delivery Substations. The O&M for Delivery Substations is 62% higher based on investment than for Network Substations. This implies that BPA's delivery facilities are in relatively poor condition compared to Network substations, requiring more time for maintenance. If the delivery substations were of higher quality, the station specific O&M would be lower which would reduce the overhead costs assigned to those facilities. NRU proposes that Utility Delivery customers continue to pay all direct O&M costs (those directly associated with the Utility Delivery facilities) but recommend other revisions in the calculation of the charge.

The Overhead categories applied to O&M (see attachment xx) represent about 43% of the total O&M cost. The categories of Marketing, Business Support, Systems Engineering, and Corporate together account for about $1.5 M or close to 25% of the overall cost for the current UDC. While overhead charges to O&M are often used to recover full costs of service, for the current UDC they are duplicative and should be eliminated; Network Transmission customers are already paying the full cost of each kW of power transmitted to them from BPA through their NT rates. The NT rate captures all of BPA's indirect overheads for transmission service. It is inappropriate to effectively double charge a Utility Delivery customer for O&M overheads. When power is scheduled to loads that are served over both Network and Delivery facilities, there are no additional transmission paths that must be identified. The Network and Delivery segments are combined into one transmission path, with the Delivery segment covering the costs of legacy low voltage facilities. Therefore, the cost of service for Utility Delivery service should be limited to the direct cost of the program rather than adding on administrative overheads, which result in a double collection of costs from Utility Delivery customers.

Discussion of Impact on Other Customers

There is no impact on other customers by adopting this proposed UDC because the UDC would recover approximately the same amount as the current rates. The revenue from the new UDC would become a component of the overall $650 M revenue requirement for the Network Segment. To the extent that any of the proposed calculations of the UDC are not 100% accurate, any revisions would not have a material impact on the rate for the Network, because the revenue shortfall from the UDC with the current methodology is less than 0.5% of the Network Revenue Requirement. While the total exposure from the proposed changes to the Utility Delivery segment for the Network revenue is nominal, the impact of not making a change for the remaining Utility Delivery customers is significant.

Effects of Changes to the UDC Over Time

Once the UDC is set, NRU recommends that it be adjusted over time commensurate with the average change in rates for PTP and NT Network service. In other words, once the methodology for determining the charge is agreed to, the UDC rate would be adjusted each rate period commensurate with the average change in the PTP and NT Network service rates. This would be more administratively efficient for BPA than trying to track all of the numbers for this declining base of facilities, and equally important, it would provide more certainty to the customers as to what they may expect regarding future costs.

Equity Between Utilities that Have and Have Not Purchased Utility Delivery Facilities

By preserving a UDC and setting it no higher than its current level of cost recovery, an incentive remains for utilities to purchase Delivery facilities to avoid the charge. Equally important, for those utilities that have recently purchased or are considering purchasing facilities, maintaining a UDC at the current level should not invalidate the overall business case for their decision.

Summary of Justification

The BPA Low Voltage Delivery Charge needs to be re-examined with the assumption that there is no continuing business need for BPA to maintain a Utility Delivery segment for purposes of rate making. Based on the analysis and methodology explained in this paper, the current level of the UDC would recover the actual costs of the service. NRU notes the significant discrepancy between the BPA UDC and the charge from the GTA providers. Other methodologies have the potential for a lower UDC than $1.399 kW/Mo. and should be explored by BPA staff and the customers in advance of the FY 2016 – FY 2017 Transmission rate case. NRU looks forward to participating in that process.

NRU Evaluation based on BPA Principles

1. Consistent with statutory requirements

a. Full and timely cost recovery

This proposal provides for full cost recovery of the actual costs of all of the low voltage delivery facilities and applies sound business principles in determining the level of the charge.

b. BPA's rates are based on total system costs

The rate proposed for utility low voltage delivery service is determined by a thorough review and revision of BPA's cost allocation methodology for assigning utility delivery costs in the context of BPA overall Network system costs.

c. Equitable cost allocation between federal and non-federal uses of the Transmission system

This proposal makes no distinction between federal and non-federal power supply. Both federal and non-federal power flow over the low voltage facilities in the current Utility Delivery segment.

d. Encourages the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles

This proposal encourages the widest possible diversified use of electric power at the lowest possible rates by not making utility delivery service for facilities below 34.5 kV prohibitively expensive in the long term, while simultaneously not increasing the currently collected costs from the other customers in the Network. Conversely, if the UDC continues to increase by 25% every rate period, the customers using low voltage delivery facilities will be paying double the NT rate compared to other customers, which would violate this principle. The NRU proposal is also consistent with sound business principles because it continues to provide an incentive for utilities to buy the low voltage facilities by retaining a UDC, which promotes BPA's goal of getting out of the low voltage delivery business.

2. Consistent with rate making principles

a. Cost causation
The proposal recovers all costs for low voltage utility delivery service using an updated cost recovery methodology as described herein using BPA data from the BP-14 rate case.

b. Simplicity, understandability, public acceptance and feasibility of application
The proposal is easy to understand, straightforward to administer, and should be acceptable to BPA transmission customers because it protects customers taking low voltage delivery service from excessive increases, while shielding other customer groups from cost increases. Utilities that have already purchased such facilities should not object because a BPA charge for low voltage delivery service is maintained.

c. Avoidance of rate shock
By limiting future increases in the utility delivery charge to the overall average increase in rates for Network service (NT and PTP), customers paying the delivery charge are shielded from rate shock. Other customer groups are not impacted by this proposal compared to the status quo.

d. Rate stability from rate period to rate period
This proposal achieves rate stability from rate period to rate period for both Network customers and customers with low voltage delivery facilities. Conversely, this principle will be violated if customers taking low voltage delivery service continue to experience 25% rate increases every rate period.

3. Considers a regional perspective
a. Alternatives include how costs are allocated and recovered
The NRU proposal fully describes how costs are allocated and recovered.

b. BPA asks that proponents of alternatives explain how the region benefits from the alternative compared to the status quo
The region benefits from this alternative compared to the status quo for three primary reasons. First, by resolving the issue of the cost basis for the UDC and basically removing it from future transmission rate cases, the transmission rate case should be less contentious between BPA and the customer groups, as well as the potential GTA related issues for the power rate cases. Second, BPA can avoid imposing a disproportionately high increase in the UDC that has a questionable analytical foundation of cost recovery, and can do so without adversely impacting other customer groups. Third, the proposed UDC maintains an incentive for utilities to purchase these facilities, while simultaneously not imposing steep cost increases for those utilities that may not be in a position to acquire these facilities to avoid the charge.

c. Historically BPA has applied uniform rates to achieve widest possible diversified use
The NRU proposal does not change BPA's application of uniform rates for transmission service.

Network Alternative 4 – Develop a "Radial" Segment – Proposed by Snohomish

Proposal Overview

Snohomish proposes identifying radial facilities on BPA's system and recovering the costs associated with those facilities from customers who utilize the identified radial facilities. There are two ways these costs could be recovered: 1) create a new segment comprised of the identified radial facilities and create a rate to recover costs associated with this segment, to be charged to customers using the identified facilities or 2) the radial facilities would remain in the Network segment, and BPA could then identify costs associated with the radial facilities and develop a charge for customers using those facilities.

Snohomish's proposal seeks to achieve a segmentation methodology that is both durable and technically justifiable. By only identifying radially-operated facilities based on a discrete set of criteria, the proposal satisfies a robust engineering and functional analysis, keeps to a limited scope and makes "radial" facilities easier to identify, allowing the function of facilities to be determined simply.

Definition of "Radially-Operated Facilities"

Snohomish defines "Radially-Operated Facilities" as Radial systems and Radial Open Loops.[1] Radial Systems are a group of contiguous transmission elements that emanate from a single point of connection; power flows in one direction from the substation to the load. Radial Open Loops are two or more Radial Systems that are connected by a Normally Open Switch (in effect, creating a gap between the Radial Systems). Radial Open Loops are, operationally, almost identical to Radial Systems. Based on feedback from BPA, analysis limited to Radial Systems is more technically manageable.

Criteria for Identifying Radial Facilities

BPA and Snohomish worked together to clarify what criteria would be used to identify radial facilities for removal from the Integrated Network segment (see appendix xx for more detail). Facilities not identified as radial facilities that are currently in the Integrated Network segment will remain in that segment.

The criteria for identifying radial facilities are listed below:

1. Radial facilities:
    a. Radial line where BPA owns connected station
    b. Radial line where customer owns connected station
    c. Looped service with a normally open switch
    d. Facilities connected by a common bus that serve looped lines (lines originate on the same bus and deliver to the same bus where power only flows to the load and not back out to the BPA system)

2. Exception for radial facilities with generation:
    a. Generation that exists on a radial line that is either wheeled or scheduled across BPA's system or flows back to BPA's system may be excluded. BPA will consider these on a case by case basis.

[1] Snohomish believes that local networks are non-integrated. However, Snohomish has decided not to include local networks in its proposal.

This analysis of radial facilities is a strictly functional analysis; voltage is not considered in radial identification.

Snohomish, as a separate proposal, also suggests a revision of BPA's Direct Assignment Policy for clarity and to assure equitable allocation of future costs. Revising the Direct Assignment Policy will ensure equitable allocation of new transmission projects.

Add finalized rate design and rate mitigation proposal as developed.

Snohomish Evaluation based on BPA Principles

1. Consistent with statutory requirements

a. Full and timely cost recovery

Snohomish's proposal will allow BPA to fully and timely collect its revenue requirement.

b. BPA's rates are based on total system costs

BPA's rates will continue to be based on total system costs.

c. Equitable cost allocation between federal and non-federal uses of the Transmission system

This proposal equitably allocates costs to users of the Transmission system, regardless of whether federal or non-federal power is being transmitted. This proposal should result in equitable rates because it reflects cost causation.

d. Encourages the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles

The Snohomish proposal does not affect actual deliveries of power, therefore the use of electric power does not change. The proposal will provide lower rates to all transmission customers for use of the Integrated Network segment by removing radially-operated facilities from the Integrated Network segment. The creation of a new segment consisting of only radially-operated facilities will provide the lowest possible rates for those customers who receive transmission service over those facilities. Non-radially-operated facilities will be excluded. Snohomish's proposal is consistent with sound business principles because it is based on cost causation and thus provides a better price signal than an arbitrary 34.5kV test that will promote efficient transmission facility decisions.

2. Consistent with rate making principles

a. Cost causation

The core of the Snohomish proposal is cost causation; the costs of radially-operated transmission facilities are separated and assigned to those who benefit from those facilities.

b. Simplicity, understandability, public acceptance and feasibility of application

This proposal would result in either a new segment or a separate charge for radial facilities. Such a charge, based on a straightforward radial test, should be simple, understandable, and feasible to apply.

c. Avoidance of rate shock

As stated as part of the Segmentation public process, any complete proposal will include a mitigation plan to avoid rate shock. This mitigation plan will depend upon the final rate effects of Snohomish's proposal, which are still to be determined.

d. Rate stability from rate period to rate period

Because of the radial nature of facilities on BPA's system, rates should be relatively stable from rate period to rate period.

3. Considers a regional perspective

a. Alternatives include how costs are allocated and recovered

This proposal addresses how costs are allocated and recovered.

b. BPA asks that proponents of alternatives explain how the region benefits from the alternative compared to the status quo

This proposal should be superior to the status quo because the proposal should result in rates based on the function of facilities used by BPA to provide various services and should result in rates that are more closely aligned with cost causation than an arbitrary 34.5kV threshold test.

c. Historically BPA has applied uniform rates to achieve widest possible diversified use

This proposal should not affect the diversified use of electricity in the region. This proposal, which is based on a functional (radial versus non-radial) analysis, is based on principles of cost causation and provides uniform rates within the proposed segments across BPA's Transmission system.

Network Alternative 5 – Develop transformation charge – Proposed by IOU/Large public coalition: Puget, Seattle City Light, Pacificorp, PGE, Powerex, Tacoma, Avista, Ibedrola, Benton County PUD

The coalition proposes that BPA develop a rate associated with transformation through the following process:

1. Identify intertie, generation integration, delivery, ancillary service, and direct assignment facilities. (Any changes to BPA's methodologies for identifying facilities in these segments is beyond the scope of this particular proposal.)
2. Network segment facilities are those remaining transmission facilities not falling into the segments in item 1 above.
3. Develop a voltage-differentiated rate for transmission on BPA's Network segment, depending upon the transformation provided.

a. Determine the average depreciated cost of substation transformation facilities, differentiated by voltage class, on BPA's Network segment. Also, determine the average depreciated cost of lines and other, non-substation facilities, regardless of voltage, on BPA's Network segment.
b. The concept is to compute rates based on
    i. the average costs of voltage-differentiated substation facilities determined in item a. above, plus
    ii. the costs of non-voltage differentiated non-substation facilities on BPA's Network segment determined in item a. above.
c. This results in transmission rates based on the service received with respect to transformation services and "postage stamp" rates with respect to other services. Each BPA customer served over the Network segment would pay costs consisting of
    i. a uniform, "postage stamp" charge for Network segment customers based on the cost of non-transformation facilities, plus
    ii. a voltage-differentiated charge for transformation based on the average cost of transformation facilities of the voltage levels used by the particular customer.

For example, rural and urban BPA transmission customers receiving deliveries of requirements power from BPA at delivery voltages at 34.5kV would all pay the same rate, regardless of location in the region.

d. BPA customers would be able to redirect transmission regardless of the voltage at the redirected POD (perhaps a different approach for "permanent redirects").
e. Charging for average losses on BPA's Network segment would continue, i.e., loss calculations would not change in the voltage-differentiated rate.

The coalition proposes that after the charges are developed that the average increase in the Network segment rate for any rate period for each voltage class (for example, the average rate increase for any voltage class is to be no more then 20%). Spread the costs of such limit pro rata to other Network segment rates, so that to the extent practicable no such voltage class experiences an average Network segment rate increase greater than 20% (for example) for any rate period. This limit mitigates any "rate shock" that may otherwise occur.

Coalition Justification

This approach more closely aligns with cost causation because it reflects different charges based on the cost of transformation services received from BPA, essentially treats customers using Network facilities at a given voltage the same regardless of their location within the region, and should not be unduly complicated to implement.

Coalition Evaluation Using BPA Principles

These BPA proposed principles are set forth below, together with some observations set forth in italics regarding the voltage-differentiated rate proposal in the context of those proposed principles.[2]

1. Consistent with statutory requirements
    a. Full and timely cost recovery

    The issue is not whether BPA will fully and timely recover its costs. The issue is which customers will pay for which facilities. This proposal attempts to provide a methodology that is relatively easy to implement while at the same time more closely aligning BPA's rates with cost causation.

    b. BPA's rates are based on total system costs

    Under the voltage-differentiated rate proposal, all of BPA's Network segment costs are allocated to rates for users of such segment. BPA should achieve cost recovery of its total Network segment costs.

    c. Equitable cost allocation between federal and non-federal uses of the Transmission system

    Under the voltage-differentiated rate proposal, Network segment rates are more closely aligned with cost causation than an arbitrary 34.5kV segmentation test because they reflect different charges based on the cost of transformation services received from BPA. This is particularly appropriate in light of the fact that BPA's lower-voltage Network facilities are used predominately to serve a subset of BPA's transmission customers. The voltage-differentiated Network segment rate would apply to BPA customers regardless of whether Federal or non-Federal power is being transmitted, yet should be equitable insofar as it would better reflect cost causation and collect the cost of lower-voltage Network facilities from the subset of BPA Network customers that are served with such facilities.

    d. Encourages the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles

    Under the voltage-differentiated rate proposal, Network segment rates are more closely aligned with cost causation because they include different charges based on the transformation services received from BPA. Such rates send a better price signal than a rate that is not voltage differentiated and are limited to collecting the Network segment revenue requirement—therefore, they should promote efficient transmission facility decisions and should be consistent with this principle. Indeed, BPA's scan of industry practices indicates that about one-third of the utilities reviewed have voltage-differentiated rates.

2. Consistent with rate making principles
    a. Cost causation

    Under the voltage-differentiated rate proposal, BPA's Network segment rates more closely align with cost causation because they reflect different charges based on the cost of transformation services received from BPA.

[2] Proponents of this alternative have noted that not all of these principles are applicable to segmentation of BPA's facilities and that these principles may not be determinative in a BPA rate proceeding.

Simplicity, understandability, public acceptance and feasibility of application

Under the voltage-differentiated rate proposal, BPA's Network segment rates reflect different charges based on the cost of transformation services received from BPA but are otherwise unchanged from BPA's current Network segment rate structure.

The "BPA Segmentation Review Industry Practices Scan" dated January 2014 indicates that about a third of the roughly 100 utility systems analyzed have voltage-differentiated rates. In other words, the voltage-differentiated rate proposal has some precedent. However, it should be noted that BPA's system seems relatively unique insofar as BPA's lower-voltage Network facilities are used predominately to serve a subset of BPA's transmission customers, while other BPA transmission customers—investor-owned utilities and larger preference agencies—provide their own lower-voltage facilities. Because of this fact, the voltage-differentiated rate proposal is particularly appropriate for BPA's system.

b. Avoidance of rate shock

Under the voltage-differentiated rate proposal, mitigation of potential "rate shock" is addressed as discussed above.

c. Rate stability from rate period to rate period

Under the voltage-differentiated rate proposal, the transformation provided to a particular customer and the average cost of transformation facilities by voltage class on BPA's Network segment should be relatively stable, and the voltage-differentiated rate proposal should result in Network rates that are relatively stable from rate period to rate period.

3. Considers a regional perspective
   a. Alternatives include how costs are allocated and recovered

   b. BPA hopes that proponents of alternatives will explain how the region benefits from the alternative compared to status quo

   c. Historically BPA has applied uniform rates to achieve widest possible diversified use

Under the voltage-differentiated rate proposal, all Network segment costs are allocated to BPA Network segment rates and should therefore be recovered. The voltage-differentiated rate proposal is superior to the status quo because it provides

(i) a uniform, "postage stamp" charge for Network segment customers based on the cost of non-transformation facilities, plus

(ii) a voltage-differentiated charge for transformation based on the cost of transformation facilities of the voltage costs used by the particular customer (which thus is better aligned with cost causation).

BPA has not always applied uniform rates,[3] nor has it shown that uniform rates achieve the widest possible diversified use consistent with sound business principles.

[3] *See, e.g.,* BP-14-B-JP06-01, pp. 16-18.

Network Alternative 6 – Apply Seven Factor Test to Create Segment Based on Function – Proposed by IOU/Large public coalition: Puget, Seattle City Light, Pacificorp, PGE, Powerex, Tacoma, Avista, Ibedrola, Benton County PUD

The coalition proposes that BPA perform an analysis of the functions performed by BPA's facilities through the following method:

1. Identify intertie, generation integration, ancillary service, and direct assignment facilities. (Any changes to BPA's methodologies for identifying facilities in these segments are beyond the scope of this particular proposal.)
2. Network segment facilities and delivery facilities are those remaining transmission facilities not falling into the segments in item 1 above.
3. Segment remaining transmission or delivery facilities using an analysis of the functions performed by BPA's facilities.
    a. As discussed below, BPA's system seems relatively unique insofar as BPA's lower-voltage Network facilities are used predominately to serve a subset of BPA's transmission customers, while other BPA transmission customers—investor-owned utilities and larger preference agencies—provide their own lower-voltage facilities. Because of this fact, segmenting BPA's system using the FERC seven-factor test or similar functional test is particularly appropriate.
4. After the segmentation and to the extent practicable, limit the proposed average increase in the Network segment rate and the distribution segment rate for any rate period (for example, the average rate increase in each rate is to be no more than 20%). Spread the cost of such limit pro rata to the Network segment rate and the distribution segment rate, so that to the extent practicable neither rate experiences an average rate increase greater than 20% (for example) for any rate period. This limit mitigates any "rate shock" that may otherwise occur.

Coalition Justification

This approach more closely aligned with cost causation because it should result in rates based on the function or usage of the various BPA facilities and should not be unduly complicated to implement.

Coalition Evaluation Based on BPA Principles

BPA has developed "BPA's Final Segmentation Principles" dated March 20, 2014. These BPA principles are set forth below, together with some observations set forth in italics regarding segmentation of BPA's facilities based on function in the context of those proposed principles.[4]

1. Consistent with statutory requirements

    a. Full and timely cost recovery

    The issue is not whether BPA will fully and timely recover its costs. The issue is which customers will pay for which facilities. This proposal attempts to provide a methodology that is relatively easy to implement while at the same time more closely aligning BPA's rates with cost causation.

[4] Proponents of this alternative have noted that not all of these principles are applicable to segmentation of BPA's facilities and that these principles may not be determinative in a BPA rate proceeding.

b. BPA's rates are based on total system costs

Under the proposal for segmentation of BPA's facilities based on function, all of BPA's Network and delivery segment costs are allocated to rates for users of such segments. BPA should achieve cost recovery of its total Network and delivery segment costs.

c. Equitable cost allocation between federal and non-federal uses of the Transmission system

Under the proposal for segmentation of BPA's facilities based on function, Network and delivery segment rates are more closely aligned with cost causation than an arbitrary 34.5kV segmentation test because such segmentation should result in rates based on the function of facilities used by BPA to provide various services. This is particularly appropriate in light of the fact that BPA's lower-voltage Network facilities are used predominately to serve a subset of BPA's transmission customers. The segmentation of BPA's facilities based on function would apply regardless of whether Federal or non-Federal power is being transmitted, yet should be equitable insofar as it would better reflect cost causation and result in rates based on segmentation of facilities reflecting the function of those facilities.

d. Encourages the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles

Under the proposal for segmentation of BPA's facilities based on function, Network and delivery segment rates are more closely aligned with cost causation because they include different charges based on the function of facilities used by BPA to provide various services. Such rates send a better price signal than an arbitrary 34.5kV segmentation test and are limited to collecting the Network and delivery segment revenue requirements—therefore, they should promote efficient transmission facility decisions and be consistent with this principle.

2. Consistent with rate making principles

a. Cost causation

Under the proposal for segmentation of BPA's facilities based on function, Network and delivery segment rates are more closely aligned with cost causation because they include different charges based on the function of facilities used by BPA to provide various services.

b. Simplicity, understandability, public acceptance and feasibility of application

Under the proposal for segmentation of BPA's facilities based on function, BPA's Network and delivery segment rate structures would remain unchanged (but would likely reflect the transfer of facilities from one segment to another).

c. Avoidance of rate shock

Under the proposal for segmentation of BPA's facilities based on function, mitigation of potential "rate shock" is addressed as discussed above.

d. Rate stability from rate period to rate period

Under the proposal for segmentation of BPA's facilities based on function, the function performed by various BPA facilities should be relatively stable, and the proposal for segmentation of BPA's facilities based on function should result in Network and delivery segment rates that are relatively stable from rate period to rate period.

3. Considers a regional perspective

a. Alternatives include how costs are allocated and recovered

Under proposal for segmentation of BPA's facilities based on function, all Network and delivery segment costs are allocated to BPA Network or delivery segment rates and should therefore be recovered.

b. BPA asks that proponents of alternatives explain how the region benefits from the alternative compared to status quo

The proposal for segmentation of BPA's facilities based on function is superior to the status quo because the proposal should result in rates based on the function of facilities used by BPA to provide various services and should result in rates that are more closely aligned with cost causation than an arbitrary 34.5kV segmentation test.

c. Historically BPA has applied uniform rates to achieve widest possible diversified use

BPA has not always applied uniform rates,[5] nor has it shown that uniform rates achieve the widest possible diversified use consistent with sound business principles.

The proposal for segmentation of BPA's facilities based on function is superior to BPA's practice "[h]istorically," which was based on an arbitrary 34.5kV segmentation test that arose in a 1996 transmission rate case settlement. As discussed above, the proposal should result in rates based on the function of facilities used by BPA to provide various services and should result in rates that are more closely aligned with cost causation and more consistent with sound business principles than an arbitrary 34.5kV segmentation test.

Montana Intertie Alternatives

IM Alternative 1 – Status Quo – Proposed by PPC

Currently services supported by the Eastern Intertie segment (including TGT, IM, and IE) are charged a rate separate from Network service. For TGT and IM this rate is developed based on $12.5M of costs identified in the Montana Intertie Agreement recovered on a pro rata share of Long Term sales over the Eastern Intertie (currently 1,746 MW). The Eastern Intertie Hourly rate is based on the Eastern Intertie segmented costs ($9.9M in BP-14) over possible Eastern Intertie sales (1,930 MW).

PPC Justification

Retention of the current rates for recovery of Eastern Intertie costs is consistent with BPA's statutory requirements and rate directives. Conversely, elimination of the IM firm transmission rate and inclusion of Eastern Intertie costs in the Network segment face broad opposition and create significant legal and policy risks for the agency. These include, without limitation:

- Creation of a precedential rate treatment for intertie facilities that is contrary to the current segmentation and recovery of intertie facility costs from users;
- Treatment of a radial transmission facility used exclusively for generation interconnection in a manner inconsistent with treatment of other similar facilities;
- Unduly discriminatory treatment of Eastern Intertie users who currently pay the TGT rate for the same services on the same facilities;

[5] *See, e.g.,* BP-14-B-JP06-01, pp. 16-18.

- Imposition of existing and future costs on Network customers without commensurate offsetting benefits to those customers in contravention of well-established rate-making principles.

PPC Evaluation Using BPA Principles

A. Summary of Previous Eastern Intertie Segmentation Litigation

BPA has maintained a separate rate segment for the Eastern Intertie since 1983, when the facility came into service and rates were set for its use. The Eastern Intertie is a radial transmission facility. Its primary use is to transmit the output of Colstrip generation for five customers. There are no requests in BPA's transmission service request queue for new long-term firm service over that path. In the BP-14 rate case, the Administrator found that "[t]hese factors indicate that the Eastern Intertie should remain a separate segment" and that "other reasons to roll in BPA's Eastern Intertie capacity have not been established."[6]

Based on the evidence in the record in the BP-14 case, the Administrator made other, more definitive findings:

- "[R]oll-in of BPA's Eastern Intertie capacity would not encourage development of renewable generation in the Pacific Northwest."[7]
- "There is a significant risk of additional costs from roll-in of BPA's Eastern Intertie capacity that has not been refuted. Because of that risk, it has not been demonstrated that roll-in would be consistent with sound business principles."[8]
- "It cannot be determined on this record whether roll-in of the Eastern Intertie would be a precedent for roll-in of the Southern Intertie."[9]

B. Consistent with Statutory Requirements

Retaining the Eastern Intertie segment ensures full and timely cost recovery. BPA has been recovering the costs of those facilities from Eastern Intertie users for decades. BPA has asserted and FERC has agreed that the BPA transmission rates as a whole, including the Eastern Intertie rates, are set at a level sufficient to recover BPA's costs. Only the costs of the Eastern Intertie facilities, net of costs recovered through the TGT rates, form the basis of the current IM rate and we do not propose to change this arrangement.

BPA does not use the Eastern Intertie facilities for delivery of federal power as part of its federal power-marketing program. Vigilante Electric's load is served with federal power over a line and transformer bay out of the Garrison substation, but those facilities are segmented to the Network and not to the Eastern Intertie. Rather, the Eastern Intertie was built solely to import non-federal electric power from generation in Montana and this remains the sole function of the line. Were additional generation to be interconnected to the Eastern Intertie facilities and delivered to loads in the Pacific Northwest, as rate case parties have asserted, the use of the line would remain unchanged; its function would remain a non-federal power import facility that interconnects with the BPA network at Garrison.

[6] Administrator's Final Record of Decision, *2014 Wholesale Power and Transmission Rate Adjustment Proceeding*, BP-14-A-02, ("BP-14 ROD") at 160-161.
[7] BP-14 ROD, at 162.
[8] *Id*. at 163.
[9] *Id*. at 164.

Rolling the Eastern Intertie costs into the Network rates would not encourage the "widest possible diversified use of electric power." There is no evidence that Montana wind development is being impeded by the existence of the current rates. This is particularly the case given that Montana wind generation is already competitive with Pacific Northwest wind generation and is asserted by some parties to be of higher quality.

BPA's rates for the Montana Intertie are currently based on the cost of those facilities and, therefore, are the lowest reasonable rates.

It must also be noted that other rate case parties have argued that rolling in the IM rate, without roll-in of the TGT rate, might be unduly discriminatory. Colstrip parties have raised this argument and it must be considered. Rolling in the TGT costs, as well as IM costs, is not a palatable option; doing so would significantly increase Network rates in a manner that is inequitable to Network customers and create concerns similar to those noted in this and the following section.

C. Consistent with Rate-Making Principles

Retention of the Eastern Intertie segment and rates satisfies the cost causation principle by allocating the costs of the facilities to the users of those facilities. The only foreseeable new users of the facilities would be non-federal generation and those parties should pay the costs of the facilities, as do the current customers who use the facilities to transmit Colstrip power into the Pacific Northwest. A proposal to allocate these Eastern Intertie costs to Network customers would violate cost causation by allocating costs to Network customers in the absence of any certain, meaningful economic benefit commensurate with the costs. A generalized regional benefit is not a sufficient rationale to support imposition of costs on Network customers. Moreover, sufficient evidence has not been produced demonstrating even a generalized regional benefit.

PPC's proposal requires BPA to take no action and as such is simple, understandable and feasible. No change is required from the rates that have been in effect in one form or another for more than twenty years. Given that these rates have been acceptable for that period up until the BP-12 case, that nothing has happened to warrant changing these rates and that proposals to eliminate these rates and roll the costs into the Network received strong and broad opposition, retention of the rates should be considered to have broad public acceptance.

PPC's proposal would not cause the rate levels to increase or the costs to be uncertain. The customers that currently pay that rate would continue to do so but no additional customers would pay the costs or the rate unless they requested transmission service over the Eastern Intertie. No potential for rate shock is created by the proposal.

The proposal would not cause a change in the way the rate is calculated or in the costs. The rate is stable from rate period to rate period to the same extent it has always been. There would not be any greater unpredictability in the rate level beyond what is already experienced.

As a general matter, transmission capacity is available on the Eastern Intertie and existing and potential customers may request it, yet no requests have been made. Given our understanding that this is the case and that no new wind plants or transmission interconnections with BPA facilities are in the permitting or construction stage, the issue of rolling-in of the IM or other Eastern Intertie rates is not ripe.

As a matter of policy and administrative law, BPA should not decide to change the current rate structure based on speculation that customers for a facility's use might somehow be created.

D. Considers a regional perspective

PPC proposes that BPA continue to allocate its share of Eastern Intertie costs to users of the Eastern Intertie facilities. The proposal does not affect cost allocation in regard to any other part of the FCRTS.

Lastly, were BPA to roll-in the Eastern Intertie costs as proposed by some parties, it would risk creating a precedent that could be used by other parties to argue for rolling into the Network the costs of other, currently segmented transmission facilities. Rolling in the Eastern Intertie costs could be seen as an invitation to roll-in the costs of generation interconnection facilities which are even more closely co-located with the network. It would be imprudent to believe that other, future rate case parties would not look for similarities between the Eastern and Southern Interties to argue for BPA to roll-in its Southern Intertie facilities. PPC does not support such proposals but the risk that they could be made should be a key consideration in BPA's decision on this issue

IM Alternative 2 – Roll IM Rate into the Network – Proposed by Gaelectric

Gaelectric proposes that the IM rate associated with Montana Intertie service over the Eastern Intertie be rolled into Network rates. Gaelectric did not propose a specific method for rolling in the IM-rate so BPA identified two methods to achieve IM roll in:

Method 1: The Eastern Intertie remains a separate segment. TGT revenues continue to be collected and credited to the Eastern Intertie segment. Over/under collection of costs associated with the Eastern Intertie are allocated to all segments based on Net Plant Investment. BPA will serve the current 16 MW subscription, and if sold the additional 184 MW it has rights to, over the Montana Intertie as part of the Network. Costs associated with IM service (defined as the pro-rata share of use over the Eastern Intertie) will be assign to the Network Segment and recovered through Network rates.

Method 2: The facilities associated with the Eastern Intertie as rolled into the Network and recovered through Network rates. The IM rate is no longer charged to IM customers. TGT revenues continue to be collected and are credited to the Network segment. This treatment means that any under/over recovery of the current "Eastern Intertie" segment would be attributed solely to the Network.

Gaelectric Justification

The IM rate has resulted in 184 MW of capacity on the Montana Intertie being stranded for over 25 years and that, as a result of RNP calling attention to this issue in the 2012 and 2014 rate setting processes, BPA eliminated certain contract terms with the other Colstrip transmission system owners and shifted the stranded costs to those parties while retaining the capacity and associated rate pancake. This means while the costs are no longer stranded from BPA's perspective (they are now a cost of the Colstrip transmission system owners), the continuing rate pancake is creating a barrier so

that the remaining capacity continues to be stranded. We have attempted to work with parties to address concerns about the precedent set by rolling in the Montana Intertie, but the opposition continued with the same arguments brought up in previous discussions and no progress was made.

We have listened to discussions on other Segmentation issues and notes that the proposed roll in of the UD segment would result in a 0.6% impact on Network rates – smaller than the 0.2% impact that is expected if the IM rate is rolled in.

During the permitting of the MT Intertie facilities, BPA made extensive arguments in Montana that the need for these facilities for regional reliability was at least as great as the need to integrate the Colstrip facilities identified in the then-current NWPP regional plan as "regional supply". This is in conflict with the opposition's arguments that the MT Intertie facilities serve only one purpose and that is to integrate extra-regional facilities.

Gaelectric Evaluation based on BPA Prinicples

The elimination of the MT Intertie rate pancake is completely consistent with BPA's segmentation principles. Indeed, continuing the status quo is inconsistent with those principles.

1. Consistent with statutory requirements
    a. Full and timely cost recovery: The Eastern Intertie investment has long since been paid for, and while there are always ongoing capital and maintenance costs associated with any facility properly maintained, the continuing costs associated with the MT Intertie are negligible in comparison to the costs of the FCRTS in total. BPA Staff analysis indicated that the impact of simply including the stranded 184 MW of capacity into rates would be 0.2% at the most, with the acknowledgement that there were no additional revenues included in the analysis from the potential increased use of the tie. Assuming even a 30% usage of the stranded capacity would make this change a net benefit from a rate perspective.
    b. BPA's rates are based on total system costs: Except for a specific 90 mile segment of double circuit 500 kV transmission under the status quo.
    c. Equitable cost allocation between federal and non-federal uses of the Transmission system: It's never been clear to me where FERC authority begins and ends with regard to Bonneville, but FERC (i.e. national) policy under both Republican and Democrat administrations has been clear since 1996 that transmission is intended to be full open access without distinction between customers. Is it "federal" use anytime a county PUD or a customer-owned utility uses the system, or only when they are taking their BPA preference supply? What about secondary sales/purchases of energy? This principle is so severely blurred as to obscure any cost element associated with the MT Intertie rate elimination.
    d. Encourages the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles: The current status of the MT Intertie is in complete violation of this principle. Despite BPA's pleadings in the original permitting hearings regarding reliability of the total grid, the position in recent years has been that the Townsend-Garrison segment was built for a single, specific purpose. As a result, a certain amount of capacity has been stranded for over 20 years.

That is an egregious violation of the most basic asset management principles, not to mention this segmentation principle.

2. Consistent with rate making principles
    a. Cost causation: Again, I note that BPA's own testimony in the permitting phase of construction of the Townsend-Garrison segment noted the critical interest this segment played in system reliability. I'm long enough in the tooth to have lived through the nearly monthly splitting and islanding of the western grid during the mid-1980s that was solved with the completion of the entire 500 kV system across Montana. With the segment between Townsend and Garrison open, we would be in the same soup we were in 30 years ago.
    b. Simplicity, understandability, public acceptance and feasibility of application: Nothing could be more simple, understandable or feasible than eliminating a completely separate rate class for 90 miles of double circuit line. As for public acceptance, any reasonable party considering the entire spectrum of segmentation issues would agree that this insignificant change is acceptable.
    c. Avoidance of rate shock: Prior opponents of eliminating the MT Intertie pancake are maintaining that a 0.6% increase in rates is insignificant when it involves rolling distribution facilities into the transmission grid, but in their past opposition, they felt that the 0.2% increase associated with eliminating the MT Intertie rate pancake was egregious. That inconsistency is neither helpful nor reasonable. I simply note that for over 20 years those that oppose this change were paying the costs that we seek to eliminate, and they didn't even know it. That speaks volumes about avoidance of rate shock.
    d. Rate stability from rate period to rate period: This will have no impact one way or another on rate stability.
3. Considers a regional perspective
    a. Alternatives include how costs are allocated and recovered: This has been covered in prior points hereunder.
    b. BPA asks that proponents of alternatives explain how the region benefits from the alternative compared to the status quo: Everyone benefits from efficient management of transmission resources. Leaving 184 MW of capacity stranded for over 20 years is poor management of assets at the very least. Planning process are purportedly looking for low cost transmission increments as evidenced through BPA's own NOS processes and various sub-regional planning processes. There is no lower hanging fruit than making use of stranded capacity. It is the transmission equivalent of conservation, which is widely embraced by virtually every reasonable party.
    c. Historically BPA has applied uniform rate to achieve widest possible diversified use: The status quo violates any reasonable perspective of achieving the widest possible diversified use. The status quo is clear: this segment can never be used for any purpose other than integrating Colstrip's coal fired production.