INDEX

REBUTTAL TESTIMONY of

RAYMOND D. BLIVEN, RONALD E. MESSINGER, REBECCA E. FREDRICKSON,

DAVID L. GILMAN, LARRY A. FURUMASU, PAUL A. FIEDLER,

and DENNIS E. METCALF

Witnesses for Bonneville Power Administration

Page

Attachments

This page intentionally left blank.

REBUTTAL TESTIMONY of

RAYMOND D. BLIVEN, RONALD E. MESSINGER, REBECCA E. FREDRICKSON, DAVID L. GILMAN, LARRY A. FURUMASU, PAUL A. FIEDLER, and DENNIS E. METCALF

Witnesses for Bonneville Power Administration

SUBJECT: SEGMENTATION

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Raymond D. Bliven, and my qualifications are contained in BP-14-Q-BPA-06. In addition to the experience listed in my qualification statement, my experience specific to this panel includes assisting in the segmentation of BPA transmission facilities for several rate cases during the 1980s, including the review of one-line diagrams and other data regarding transmission facilities and their usage. In addition to my BPA experience, I also filed rebuttal testimony on segmentation topics on behalf of the direct service industries in the WP-96 rate case, offering alternative methods for Fringe segmentation. Schoenbeck and Bliven, WP-96-E-DS-11.

A. My name is Ronald E. Messinger, and my qualifications are contained in BP-14-Q-BPA-46.

A. My name is Rebecca E. Fredrickson, and my qualifications are contained in BP-14-Q-BPA-21.

A. My name is David L. Gilman, and my qualifications are contained in BP-14-Q-BPA-24.

A. My name is Larry A. Furumasu, and my qualifications are contained in BP-14-Q-BPA-22.

A. My name is Paul A. Fiedler, and my qualifications are contained in BP-14-Q-BPA-18.

A. My name is Dennis E. Metcalf, and my qualifications are contained in BP-14-Q-BPA-47.

Q. What is the purpose of your testimony?

A. Several rate case parties, including Joint Party 6[1] (JP06), Joint Party 12[2] (JP12), the M-S-R Public Power Agency (MSR), and Powerex (PX), have raised issues regarding the segmentation in our Initial Proposal. Specifically, these parties maintain that some of the facilities included in the Integrated Network (hereinafter referred to as "Network") segment should be removed from the Network because they do not support the Network and are not used by all network customers. We respond to these issues. In doing so, we describe the development and implementation of BPA policies that support the segmentation in the Initial Proposal.

Section 2: Supportive Comments

Q. Do any parties support elements of the Initial Proposal segmentation?

A. Yes. Joint Party 3[3] (JP03) submitted comments supporting our proposed segmentation.

Q. What aspects of your proposal did JP03 support?

A. JP03 supports our approach of using the 34.5 kV bright-line voltage threshold, recognizing that this threshold has been in place for more than 20 years and has provided stability for the set of costs for which each customer class is responsible. Scott and Carr, BP-14-E-JP03-02, at 3-4. JP03 argues that there has been no change in circumstances that warrants a change in BPA's segmentation policy. *Id.* at 4.

---

[1] Avista Corporation, Portland General Electric Company, and Puget Sound Energy, Inc. comprise Joint Party 6.
[2] Benton County Public Utility District No. 1, Iberdrola Renewables, LLC, Tacoma Power, Seattle City Light, and Snohomish County Public Utility District No. 1 comprise Joint Party 12.
[3] Northwest Requirements Utilities and Pacific Northwest Generating Cooperative and Members comprise Joint Party 3.

Section 3: Segmentation of Lower-Voltage Facilities

Q. *Please summarize the basic issue raised by the parties that oppose your proposal.*

A. The parties argue that certain transmission facilities that were installed and are used to serve only a subset of BPA's transmission customers should not be included in the Network segment. *See, e.g.,* Holland *et al.*, BP-14-E-JP06-01, at 5; Hanser *et al.*, BP-14-E-JP12-01, at 19; Arthur, BP-14-E-MS-01, at 26; and Opatrny, BP-14-E-PX-E01, at 8. Specifically, the parties argue that a large number of lower-voltage facilities perform a function more like distribution than transmission. Holland *et al.*, BP-14-E-JP06-01, at 5; Hanser *et al.*, BP-14-E-JP12-01, at 19; Opatrny, BP-14-E-PX-E01, at 8. The parties argue that the Network segment includes facilities that were installed and used to serve only a subset of BPA's transmission customers. Holland *et al.*, BP-14-E-JP06-01, at 7; Hanser *et al.*, BP-14-E-JP12-01, at 20; Arthur, BP-14-E-MS-01, at 27; Opatrny, BP-14-E-PX-E01, at 17. JP12 identifies more than 70 facilities that should be partially removed from the Network and more than 400 facilities that it argues should be entirely removed from the Network segment. Hanser *et al.*, BP-14-E-JP12-01, Attachment 3. Altogether, JP12 identifies about one-sixth of investment and one-quarter of operations and maintenance (O&M) that should be removed from the Network segment. Powerex endorses JP12's analysis as a starting point for BPA to do a full functional analysis. Opatrny, BP-14-E-PX-E01, at 26. JP06 and MSR do not identify specific facilities that should be removed from the Network segment.

Q. *Do you agree with the parties' proposal to remove these facilities from the Network segment?*

A. No. As we describe below, their proposal would effectively require smaller and usually rural customers that take power at lower voltages and over longer transmission lines to pay more for transmission service than larger and usually urban customers. This is a fundamental departure from BPA's longstanding transmission rate policies encouraging the widest possible diversified use of electric power at the lowest possible rate to consumers in the Pacific Northwest as required by section 9 of the Federal Columbia River Transmission System Act (Transmission System Act), 16 U.S.C. § 838g, and sections 2 and 6 of the Bonneville Project Act (Project Act), 16 U.S.C. §§ 832a(b) and 832e. More directly, the parties' proposal is inconsistent with congressional intent for the development of Federal power in the Pacific Northwest. The parties' proposal would create a number of issues that BPA would have to address before implementing. Their proposal also arguably does not conform to the national ratemaking policies the parties appeal to; rather, these policies favor rolling in the costs of transmission assets.

Section 4: Policy Basis for the Composition of the Network Segment

Q. Please describe why BPA was created, and its mission.

A. BPA was created in part to extend electric service to the primarily rural portions of the region that were without service at the time. Before the development of the Bonneville Project, power and transmission development in the Northwest took place around the population centers, primarily Seattle and Portland. It was not profitable for investor-owned utilities to provide electric service to remote communities and farms. As a result, large sections of the Northwest remained without the benefit of electricity that the more populated areas were enjoying.

When Franklin Delano Roosevelt was elected President in 1932, one of his primary New Deal policies was to harness the power of the Columbia River for public benefit by building the Bonneville Dam and eventually other hydroelectric dams. When presidential candidate Roosevelt appeared in Portland in September 1932, he told the crowds:

> I therefore lay down the following principle: That where a community, a city or county or a district is not satisfied with the service rendered or the rates charged by the private utility, it has the undeniable right as one of its functions of government, one of its functions of home rule to set up after a fair referendum has been taken, its own governmentally owned and operated service.
>
> * * * *
>
> We have, as all of you in this section of the country know, the vast possibilities of power development on the Columbia River. The next great hydroelectric development to be undertaken by the federal government must be that of the Columbia River.
>
> This vast power can be of incalculable value to this whole section of the country. It means cheap manufacturing production, economy and comfort on the farm and in the household. Your problem with regard to this great power is similar to our problem in the state of New York with regard to the power development of the St. Lawrence river.
>
> Here you have the picture of four great government power developments in the United States—the St. Lawrence River in the northeast, Muscle Shoals in the southeast, the Boulder Dam project in the southwest, and finally, but by no means the least of them, the Columbia River in the northwest. Each one of these will be forever a national yardstick to prevent extortion against the public and to encourage the wider use of that servant of the American people—electricity.

The Oregonian, September 22, 1932, page 6, Portland, OR.

Development of the Bonneville Dam marked the next great chapter[4] of public power in the Pacific Northwest. As described further below, while there was a considerable amount of regional disagreement over who should reap the electric generation benefits from the dam, when the smoke cleared the congressional intent with regard to how the benefits should be distributed was clear:

[4] Public power had already begun to develop in Tacoma in 1884 and Seattle in 1890. Before 1936, Tacoma was operating 148 MW of generation, and Seattle was operating 109 MW of generation. Other smaller municipal systems were in operation, and public utility districts were beginning to be formed. A few cooperatives also existed in the region at this time.

> *In order to encourage the widest possible use of all electric energy that can be generated and marketed and to provide reasonable outlets therefor*, … the administrator is authorized and directed to provide, construct, operate, maintain, and improve such electric transmission lines and substations, … for the purpose of transmitting electric energy, available for sale, from the Bonneville project to existing and potential markets, … to interconnect the Bonneville project with other Federal projects and publicly owned power systems constructed on or after August 20, 1937.

16 U.S.C. 832a(b) (emphasis added).

> In order to insure that the facilities for the generation of electric energy at the Bonneville project shall be operated for the benefit of the general public, *and* particularly of domestic *and rural consumers*…

16 U.S.C. § 832c(a) (emphasis added).

> Schedules of rates and charges for electric energy produced at the Bonneville project and sold to purchasers … *shall be fixed and established with a view to encouraging the widest possible diversified use of electric energy. The said rate schedules may provide for uniform rates or rates uniform throughout prescribed transmission areas in order to extend the benefits of an integrated transmission system and encourage the equitable distribution of the electric energy developed at the Bonneville project.*

16 U.S.C. § 832(e) (emphasis added).

As shown above, from its very beginning, BPA's mission was different from that of investor-owned utilities. BPA was required to establish policies that encourage the widest possible diversified use of power to consumers in the Northwest. While financial considerations were important, so were the social considerations as to how the power was distributed.[5] To accomplish this mission, BPA implemented from its very beginning a policy of providing uniform rates for the delivery of power to loads within the Pacific

[5] Smaller industries really employ more labor and are vastly more advantageous to the region. They largely eliminate the monopolistic danger. Power experts aver that modern high-power transmission lines make it cheaper to carry current to industry than to ship raw materials to the switchboard, even by water transportation. It is better to move electricity than to move goods and produce. The day of crowding around a plant is gone. This offers some hope to many communities along the Columbia and near its bank. The social factor is not negligible, as the President has pointed out. We want no more crowded slum cities. (Rep. Walter M. Pierce, Oregon 3rd District, House Congressional Record, May 12, 1937, at 4434.)

Northwest. These requirements and policies are still in effect through BPA's current segmentation implementation.

Q. What are the basic principles of uniform rates?

A. From its founding, BPA has maintained a policy of providing transmission at uniform rates to the Pacific Northwest region. Uniform rates are also referred to as postage-stamp or blanket rates; they provide service at the same price without regard to the consumer's distance from the generator. In the beginning, this policy was specific to the delivery of Federal power throughout the Pacific Northwest region. The segmentation that we propose is a natural extension of this longstanding policy now implemented in an industry that has unbundled power and transmission rates and that provides open transmission access to all eligible customers. It also provides access to Federal and non-Federal power sources at the same transmission rates for BPA's preference customers.

Q. How did this longstanding uniform rate policy come to be?

A. The earliest proposals for uniform rates for delivery of power from Bonneville Dam started with a 1935 report by the Pacific Northwest Regional Planning Commission, *Regional Planning Part I - Pacific Northwest*. This proposal was in direct contrast to the position of the Portland Chamber of Commerce, which, to entice industry exclusively to the Portland-Vancouver area, advocated either for a low switchboard (*i.e.*, bus bar) rate for power or for free transmission service as far as the Portland-Vancouver area. *Columbia River Power for the People, A History of Policies of the Bonneville Power Administration*, U.S. Government Printing Office, 1981, at 79.

The opponents of uniform rates wanted to establish rates for Federal power based on the distance from the Bonneville Dam to the customer's load. That way, remote communities and farms not located near the Bonneville Dam would not be able to afford to take advantage of the power, while residents and businesses in the Portland-Vancouver area would. The opponents' argument was that the customers that caused the cost of constructing transmission facilities to take advantage of Federal power should pay all the costs of those facilities. This position was opposite to that of the progressive New Deal movement, which was promoting rural electrification through socializing the costs of power generation and transmission.

In 1936, Frederic A. Delano of the National Resources Planning Board appeared before the Senate Committee on Agriculture and Forestry. Delano was asked whether he envisioned the same wholesale rate for northern California [*i.e.*, the Copco area on the Klamath River] as for Portland. Delano concluded: "We favor, in general terms … what might be called the blanket rate system." *Id.* at 81.

Later in 1936, President Roosevelt sent a letter to the Federal Power Commission (FPC) asking for a recommended rate structure suitable for marketing Bonneville power:

> In this connection, I wish to remind you that the advisory committee of the National Resources Committee in its report on this general subject laid special emphasis on the importance of a rate structure which will not lead to the future congestion of industry close to generating units, but in preference *distribute the benefits of the Columbia River over as wide an area as practicable*. In the opinion of the committee a system like the English grid or that adopted by the Tennessee Valley Authority would be desirable and should at least have the careful consideration of the Federal Power Commission.

Id. at 83 (emphasis added).

While awaiting the FPC's report, President Roosevelt appointed a committee to draft legislation to create a Federal agency to market the power from the Bonneville Dam and outline a national policy for Federal power projects. The chair of this committee was Secretary of the Interior Harold Ickes. The committee endorsed the 1935 regional report, offering an explanation and justification for a uniform rate:

> It would appear that a wise national policy will see to it that this new resource is so distributed as to achieve the maximum regional and national benefit.

> That requires that the surplus electric energy from Bonneville, Grand Coulee, and such future federally financed public works on the Columbia River and its tributaries as may be built shall become available *to the greatest number of people at the lowest practicable rates* consistent with the solvency of the works used for generation, transmission, and distribution of such energy. It follows that the operating agency should adopt a policy for the sale of electricity which will make *rates similar over large areas*, which will pass along the economies in the prices of wholesale power to the ultimate consumer, and which will contribute, insofar as may be wise, to the stabilization of existing communities, the appropriate decentralization of new industries, the increase of steady employment, and the increased consumption of electric energy by farmers and domestic consumers.

Id. at 80 (emphasis added).

The House Committee on Rivers and Harbors held hearings on the draft Bonneville legislation, with Oregon Governor Martin appearing before the committee describing those who wanted uniform rates as "wrecking crews," people who were of a "wild school of thought" that sought to destroy the benefits of the dam. "Giving the same rate from Bonneville all over the Pacific Northwest, as some advocated – that's damned nonsense," he retorted to Congress. *Id*. at 83. Secretary Ickes also appeared at these hearings, stating:

> The Power Policy Committee recommended that the Administrator should have the authority to establish uniform rates or rates uniform throughout prescribed transmission areas. It was not suggested that the rates must be uniform or that the rates should be the same as those charged for power developed at other projects under substantially different conditions and costs. But it was suggested that there should be nothing in the act which should require the Administrator to sell power at the switchboard at a price which should exclude all costs of transmission. *Such a policy would impose an undue cost upon distant customers and would narrowly restrict the market outlets for power*. Such a policy would be very short-sighted, because cheap power depends upon the development of wide markets. It is unthinkable that the benefits of national expenditures for the development of power should be confined to a small area near the power site and not distributed equitably among the communities within transmission distance. *A wise national policy requires that the Administrator be given adequate power to treat transmission costs wholly or partly as an overall charge so as to develop the widest possible markets for power in the great Northwest*.

Hearings Before The Committee on Rivers and Harbors, House of Representatives, H.Rep. 7642, 75th Cong., 1st Sess., March, April, May, and June, 1937, at 143 (emphasis added). Mr. Mott, representing Oregon's First Congressional District, further testified that:

> In other words, to use Mr. Carter's illustration, *if you are going to build a transmission line from Bonneville to Roseburg Oreg., which would be a distance of nearly 300 miles, the people of Portland, who are only about 50 miles away from Bonneville, should bear just as great a share of the burden of that long transmission line as the people down in Roseburg, who are going to get the benefit of it.*

Id. at 210 (emphasis added). Mr. Rankin, representing Mississippi's first district, explained it this way:

> Another thing on this rural electrification is that if you undertake to charge a man for his line, the farmer in your district living on the back side of his place from the road will be shut off, and what I am trying to do is to organize a whole country system, a network, so that the man living on an isolated hillside who could not build a line himself, will get the benefit of this power at reasonable rates.

Id. at 255.

President Roosevelt ultimately concluded the uniform rate question should be left open for future determination by the Administrator, but wanted the Project Act to contain ratemaking guidance. As a result, the Project Act vested the Administrator with discretion with respect to ratesetting but included specific authority to set uniform transmission rates. One of the primary authors of the legislation explained the uniform rate provision as follows:

> This is not in the Boulder Canyon Act, it is not in the Muscle Shoals Act. It is sought by their provision to make certain that any benefits which may accrue shall not be provincial in their application but shall be distributed as far as is practicable, a matter which can only be worked out through experience and study. But we have placed no limitations on the area of distribution. The language encourages a wide and equitable distribution of the benefits of the

> rates which may be enjoyed by the people who live in the great Northwest section of this country.

Sen. Charles L. McNary, Oregon, Senate Congressional Record, August 9, 1937, at 8523.

Q. *Did the passage of the Project Act settle the rate wars?*

A. No. By giving the Administrator discretion regarding rate design, the Project Act shifted the battlefield to the appointment of the first Administrator that would implement the rates. At the time of signing of the Project Act, the leading candidate was J.D. Ross. Ross was superintendent of Seattle City Light, a position he had held since 1921, and sat on the Securities and Exchange Commission. Ross was a vocal proponent of uniform rates throughout the region, and a friend of President Roosevelt and Secretary Ickes. The Project Act empowered the Secretary of the Interior to appoint the Administrator, and the personal friendship and shared views on rates made Ross an easy choice for Ickes.

However, Ross's connections did not stop Governor Martin and other Oregon interests from mounting a vigorous campaign against him. Gov. Martin, Rep. Nan Wood Honeyman from the Portland area, Portland Mayor Joe Carson, and business representatives took a parochial position by demanding that an Oregonian be appointed to the job, someone who would support local Oregon interests by setting low rates for power in the immediate area with rates increasing with the distance from the dam.

The Oregon interests did not succeed in overcoming the advantages that Ross held, and Ickes appointed him as the Administrator. Before setting the first rates, Ross turned to the FPC rate report produced in response to the President's study request. The FPC had concluded:

> With respect to the second question--the zoning of rates for power within the economic Bonneville area according to the distance from the project or otherwise--various opinions have been expressed. In this report it has been recognized that power delivered very close to Bonneville can be sold at rates reflecting the resultant savings in transmission costs. Having once incurred heavy transmission investments in order to deliver firm power throughout the

> remainder of the economic area beyond this nearby zone, *it has been considered in this report that wholesale rates for power delivered from these transmission lines should be uniform for this project*.

Bonneville Rate Report, Federal Power Commission, March 1937, at 6 (emphasis added).

Next, Ross undertook to find out the mind of the people in the Northwest on the rate form that BPA should use. In the spring of 1938, he held public meetings in Olympia, Boise, Spokane, Walla Walla, Yakima, Portland, Pendleton, and Salem. Claude L. Draper, chairman of the FPC, accompanied Administrator Ross and participated in each of these public meetings. The comments they received overwhelmingly supported the creation of uniform rates. For example, at the Yakima meeting John Whitehead, the first manager of Benton PUD, stated:

> I think we have done more work throughout the Yakima Valley in attempting to bring cheap power here; and I have worked for Mr. Ross a lot, and a lot of what I am saying he has already heard. We are building a line down there approximately 64 miles long at the present time, and we are buying power from the power company at about 12 mills, and that 12 mills represents one-third of our income, gross revenue. Mr. Ross just stated it would be possible to bring Bonneville power there, so this would figure one-sixth to one-eighth of our revenue, and power cost. I can readily see if we were asked to purchase for these customers at that particular rate we would be able to reduce our present retail rate at least one-half. … *Then regarding your zoning, I fee1 our district and the men that we are connected with and the work that we are doing are very much in favor of a flat rate and not a zone rate*. We believe that the whole territory will gradually develop itself, and under the plans that are being worked out, all of our power, including the Pacific Power & Light system, all of that, will all come in under a general program and be connected to a network; and when we buy power, even if we sign up for Bonneville power, we may not even be getting Bonneville power but getting power from Yakima and some other place, by displacement methods. *So it seems to us the only practical method is a flat rate system* and that particular rate, of course, is mathematical and for the engineer to figure out.

Transcript of BPA Public Hearing at Yakima, Washington, at 24-25 (March 17, 1938) (emphasis added).

After concluding the public meetings, Administrator Ross established, and the FPC approved, rates that provided a uniform $17.50 per kilowatt annual rate for power delivered anywhere along the transmission system, and $14.50 per kilowatt for power delivered within 15 miles of the dam, known as the at-site discount. These rates, as low as 2 mills per kilowatthour depending on load factor, were in effect until 1965, even as the costs of Grand Coulee Dam and 13 other Federal dams were added to the power system.

Q. Was there significant usage of the at-site discount?

A. It does not appear so. There was certainly no large scale development of industry around Bonneville Dam, or any other dams as they developed. One aluminum smelter was sited next to John Day Dam, and we believe it received the at-site discount until the discount was removed in the 1979 rates. The city of Cascade Locks did not receive the at-site discount when it was connected in 1938, even though the city was only five miles from Bonneville Dam. We believe that this is because the city was served over BPA transmission lines instead of its own lines, and the first rate discount provided that the customer would take delivery from BPA without use of BPA lines.

Q. You have been talking about power rates so far. How does this history relate to transmission rates?

A. In the early years, transmission costs were considered a part of the total cost of delivering power. Wheeling power for other entities was not a significant use of BPA's transmission lines until the 1960s and 1970s. Early wheeling customers paid rates established by contract. The implementation of the Columbia River Treaty in 1964, the energization of the Pacific Northwest-Pacific Southwest AC and DC interties in 1968, and the advent of the Hydro-Thermal Power Program in the 1970s led to increased usage of BPA's transmission system by non-Federal power. The increasing number of wheeling requests focused more attention on appropriate rate levels for wheeling, which led to BPA's filing its first rate schedules for wheeling with the FPC in 1976. In that filing, BPA established rates for wheeling pursuant to Formula Power Transmission (FPT) contracts that charged wheeling customers based on their usage of specified elements of BPA's transmission system, including consideration of the transmission distance. BPA stopped offering FPT contracts in the early 1980s and began offering Integration of Resources (IR) contracts, which charged wheeling customers demand and energy rates for the use of BPA's network facilities without specifying the facilities used. Other than a discount for transmission distances under 75 miles, there was no distance component in the IR rate.

Q. When did BPA first segment the transmission system?

A. The FPT contracts did not require segmentation, because each wheeling customer was charged based on its deemed use of main grid and secondary system classes of facilities—in one sense, a *de facto* segmentation—at rates based on the total cost and total use of each class of facility.

The Transmission System Act, which was signed into law in 1974, provides for the operation, maintenance, and continued construction of the Federal Columbia River Transmission System. Section 10 of the Act requires BPA to equitably allocate transmission costs between Federal and non-Federal power. 16 U.S.C. § 838h. This requirement, coupled with the changeover to IR transmission contracts (which, unlike FPT contracts, provided for network service without identifying the usage of specific facilities) led to the development of segments that recognized the different kinds of uses of the transmission system. More specifically, BPA needed to identify which facilities were being used to wheel non-Federal power so that IR (wheeling) customers would not be charged the costs of the facilities used to transmit Federal power only. Stated another way, BPA began segmenting its system as a way of ensuring that Federal and non-Federal power uses of the transmission system were equitably allocated.

BPA first applied segmentation to wheeling rates (also referred to simply as transmission rates) and bundled power rates in the 1981 rates. Lower-voltage facilities (generally 12 kV to 69 kV) were segmented into the Delivery segment, and higher voltages (69 kV to 500 kV) were divided into the Network and Fringe segments.

Q. Was segmentation the only ratemaking factor in ensuring equitable allocation of costs between Federal and non-Federal power?

A. No. Segmentation was only the first step. BPA determined which facilities were used almost exclusively by Federal power and segmented those facilities to the Fringe segment. However, both Federal and non-Federal power customers used the Network segment. Therefore, the second step was to determine how much each group used the Network segment. BPA developed allocation factors based on usage to allocate Network segment costs between Federal power sales and wheeling (use of transmission by non-Federal power). The amount of the Network revenue requirement allocated to wheeling was the amount to be recovered through FPT and IR rates.

Q. If segmentation dealt with the equitable allocation of costs between Federal and non-Federal power, how was BPA's policy of uniform transmission rates implemented at that time?

A. The Network segment costs allocated to Federal power sales, along with the costs of the Fringe and Delivery segments, were included in bundled power rates. Power customers, without regard to location, delivery voltage, or distance from generation, were charged the same, uniform bundled power rates. Under the IR rate, wheeling customers using the network were likewise charged for their use of Network facilities without regard to location, delivery voltage, or distance from generation. As with power rates that previously allowed an at-site discount, wheeling rates included a short-distance discount.

Q. When did this particular implementation of uniform rates change?

A. BPA changed how it applied its uniform rate policy in 1996 as a result of changes in the electric industry. The industry was separating power and transmission functions, unbundling transmission costs from power rates, and adopting policies to open electric power markets to more competition. In response, BPA separated its power and transmission functions into separate business lines, established unbundled power rates, established transmission rates that applied to both Federal and non-Federal power, allowed power customers to begin diversifying their power supply to include more non-Federal sources, and established an open access transmission tariff for all power and wheeling customers. One important development during this time was that BPA signed transmission contracts with power customers that provided transmission service without regard to whether they were served with Federal or non-Federal power. Before these contracts, BPA sold Federal power delivered to the customers' load centers. Beginning with the 1996 rates, BPA sold power at the Federal bus bar, and the customers then used their transmission contracts to wheel their power from the bus bar to their load centers.

Q. How did these changes affect segmentation in the 1996 rate case?

A. First, the industry changes removed the distinction between Federal and non-Federal power that in prior cases was used as a basis to distinguish the Fringe segment from the Network segment. Therefore, BPA Staff proposed to roll the Fringe segment into the Network. Gilman *et al.*, WP-96-E-BPA-28, at 2-3. Second, the Network needed to be redefined to distinguish between transmission and delivery functions, because all power using the transmission system was now treated as wheeling. Therefore, Staff proposed that all facilities above 34.5 kV be included in the Network segment. *Id*. As described below, the rate case ultimately settled, with facilities at or above 34.5 kV being rolled into the Network segment and those below 34.5 kV being included in the Delivery segment and subject to a separate delivery charge. This change would allow customers to receive transmission service at a uniform transmission rate without respect to location or voltage.

Q. Please explain why BPA eliminated the Fringe.

A. The Fringe segment, which included facilities used primarily to transmit Federal power, could not coexist with national policies designed to open power markets to all sources. Also, because customers now had options for their power supply (Federal or non-Federal), the facilities in the Fringe segment would be continually changing as customers changed power sources. If the Fringe segment had remained, preference customers could have been exposed to different rates depending on whether they chose all Federal or some non-Federal power sources.

Q. Please explain why the Network segment includes facilities at 34.5 kV.

A. First, 34.5 kV is the minimum voltage level that provides all customers with transmission service without respect to location, size of customer load, or distance from generation sources at the same rate. Second, although the Staff proposal in 1996 was to draw the line to exclude 34.5 kV facilities (which would have provided most customers with transmission service at the same rate), the settlement of the 1996 transmission rate case provided that the line be drawn to include 34.5 kV. Our proposal in this case is to continue to include 34.5 kV facilities, because they predominantly perform a transmission function. Transmission Segmentation Study (Study), BP-14-E-BPA-06, at 4.

Q. *How does segmenting facilities below 34.5 kV to the Delivery segment support the uniform rate policy?*

A. The facilities below 34.5 kV are not necessary for BPA to provide transmission service. In our understanding of the configuration of BPA's and customers' systems, all of the facilities classified as "below 34.5 kV" are used to step down power from transmission voltages to distribution voltages. *Id.* at 6. Prior to 1996, BPA had installed these facilities to step down power to distribution voltage for some customers but not for others. By including in network transmission rates these facilities that BPA built, the result would be non-uniform transmission rates between the customers that had BPA transformation and those that had to build their own. Therefore, the 1996 decisions to institute a delivery charge and to begin selling Delivery segment facilities are actually more in keeping with the uniform rate policy than had BPA rolled the below-34.5 kV costs into the Network segment; this allowed BPA to serve all of its customers on a more equal basis.

Q. *Did BPA implement any other policies with respect to below-34.5 kV facilities in the 1996 rate case?*

A. Yes. BPA began a program of selling Delivery segment facilities to the customers using them, wherever feasible, which allowed BPA to begin withdrawing from the low-voltage business and also allowed the customer to avoid paying the delivery charge. WP-96 Wholesale Power Rate ROD, WP-96-A-02, at 535. The facilities in this segment were generally remote, low-voltage facilities closer to BPA's customers than to BPA's maintenance offices. It made sense for the customer to own, operate, and maintain these facilities, since the they were providing a distribution-like function. Ultimately, BPA wants to get out of the delivery business altogether and have only uniform network transmission rates on its transmission grid within the Northwest.

Q. *JP12 identifies a number of facilities that it claims perform functions similar those in the Delivery segment. Hanser et al., BP-14-E-JP12-01, at 29-30. Would separating these costs into a different rate also be more in keeping with the uniform rate policy?*

A. The difference is that our Delivery segment facilities are not needed to provide transmission service, whereas the facilities identified by JP12 are needed to provide transmission service. Our proposal is not just a question of trying to put all customers on an equivalent facility basis; it is also about providing equivalent transmission service. When the 1996 decisions were being made, the question was, and remains, the appropriate demarcation between providing transmission service and providing step-down transformation to distribution facilities. We have determined that the facilities in the Delivery segment are those providing step-down transformation to distribution facilities.

In contrast, the 34.5 kV (and higher-voltage) facilities are needed to provide transmission service. The bulk of BPA's 34.5 kV transmission lines were acquired through a transfer of lines built by the U.S. Bureau of Reclamation prior to the 1960s. However, once updated financial records are incorporated into the final segmentation study in this rate case, all of these transmission lines will have been removed from the Network segment through retirement or sale. See section 14 below. At that point, only one 34.5 kV transmission line will remain in the Network segment. We discuss the distinctiveness of this line in the next section. The remaining 34.5 kV facilities provide step-down transformation. As discussed below, the vast majority of 34.5 kV facilities are connected to customer-owned transmission facilities. Thus, while BPA's 34.5 kV facilities provide step-down transformation, it is transformation to a lower transmission voltage, not a distribution voltage.

Q. How does JP12's proposal depart from BPA's longstanding uniform rate policy?

A. JP12 proposes to exclude a significant number of transmission facilities from the Network segment, mostly facilities that are 115 kV and below. JP12 would exclude all or a portion of 248 of the 732 substations (one-third of the substations) and 212 of the 616 transmission lines (one-third of the lines) that are in the Network segment. Ninety percent of the excluded substations, or 217 of the 248, and 78 percent of the excluded transmission lines, or 165 of the 212, are serving areas outside the more urbanized areas of the Pacific Northwest (generally from Everett to Olympia, including the Kitsap Peninsula; Vancouver to Salem; Eugene; Tri-Cities; Spokane; and Boise). Thus, under JP12's voltage-based proposal, rural and distant areas of the region would face higher transmission rates solely because they are smaller load-service areas. In this regard, JP12's proposal essentially resurrects the issues regarding BPA's mission to promote the widest possible diversified use of its power at the lowest possible rates that were resolved years ago in the Project Act and the development of the uniform rate policy that we discuss above. JP12's proposal would not allow for uniform transmission rates; nor would it allow for rates uniform throughout prescribed transmission areas, the two rate forms mentioned in the Project Act.

Q. Is your segmentation proposal consistent with BPA's founding mission?

A. Yes, for the reasons set forth above, it allows for uniform transmission rates.

Section 5: Transmission versus Distribution

Q. Please summarize the arguments that the parties make regarding distinctions between transmission and distribution.

A. JP06 claims that BPA has installed delivery facilities solely for the purpose of delivering power to certain customers. Holland *et al*., BP-14-E-JP06-01, at 8. JP06 argues that merely labeling the transfer of power between substations at a 34.5 kV voltage as "transmitted" does not make the facilities transmission facilities. *Id*. at 9.

JP12 argues that including non-Network facilities in the Network segment is not consistent with cost causation. Hanser *et al*., BP-14-E-JP12-01, at 20. JP12 states that Network customers should not bear the burden of paying for non-network facilities that serve only certain customers and provide no systemwide benefit. *Id*.

Powerex claims that many of BPA's low-voltage facilities do not appear to serve transmission purposes, but instead are used to deliver power to particular customers. Opatrny, BP-14-E-PX01-E01, at 7-8. Powerex argues that this is a "distribution-like" function. *Id*. Powerex argues that including lower-voltage facilities in the Network segment is inconsistent with cost causation principles. *Id*. at 14.

Q. Do you agree that there are distribution facilities in the Network segment?

A. No. According to JP12, the fact that BPA has identified facilities as providing a distribution-like function means that BPA owns distribution. Hanser *et al*., BP-14-E-JP12-01, at 15. Similarly, Powerex argues that to differentiate between "distribution-like" and "distribution" is a distinction without a difference. Opatrny, BP-14-E-PX01-E01, at 13. Notwithstanding some similarities, we see an important distinction between distribution and distribution-like facilities. Distribution facilities are used to deliver power to retail customers at low voltages, generally over relatively short distances. BPA does not have any retail customers, especially customers of the type that are served over distribution facilities. Distribution facilities deliver power at low voltages, almost always with multiple retail customers served from each distribution line. BPA does not own any distribution facilities.

BPA does own some facilities that most likely would be functionalized as distribution facilities if BPA were a retail utility. We have identified such facilities and segmented them to the Delivery segment. To do this, we used the low-side voltage of the transformer to guide the segmentation. The facilities that we identified as "distribution-like" are treated in the manner that the parties advocate, and the parties do not argue that any facilities we have proposed as Delivery are inappropriately treated. Thus, from our view, the parties' argument really is not about whether BPA owns any distribution, but whether BPA has appropriately identified its distribution-like facilities and whether any of these distribution-like facilities are included in the Network segment. The actual disagreement is about whether particular facilities are distribution-like.

Q. Are there any distribution-like facilities in the Network?

A. We have not identified any. The only facilities that are in the Network segment that could arguably be considered distribution-like facilities are the 34.5 kV facilities. However, a majority of these facilities perform a transmission function, not a distribution-like function.

Q. Can you give some examples?

A. Yes. JP12 includes a portion of BPA's one-line diagram of one such facility, the Mapleton substation, in Exhibit 2 to its testimony. Hanser *et al.*, BP-14-E-JP12-01, Exhibit 2 at 2. At Mapleton, BPA delivers power to both Central Lincoln PUD and Blachly-Lane Cooperative. BPA's one-line diagram shown in JP12's Exhibit 2 makes the deliveries to each of these customers look very much alike. A 115 kV bus connects to two transformers. One of the transformers steps down the voltage to 12.5 kV for delivery to Central Lincoln. The other transformer steps down the voltage to 34.5 kV for delivery to Blachly-Lane. JP12 argues that we have inappropriately included the 34.5 kV transformer in the Network segment while including the 12.5 kV transformer, performing the same function, in the Delivery segment.

What is not on BPA's one-line diagram is what happens after the power is delivered. The power delivered at 12.5 kV to Central Lincoln travels about 200 feet to a Central Lincoln distribution station that serves the Mapleton community over its distribution lines. The power delivered at 34.5 kV to Blachly-Lane travels 11.5 miles before being stepped down to 12.5 kV for distribution to Blachly's retail customers. The intervening 11.5 miles are not within Blachly's service territory, meaning there are no retail service drops between BPA's Mapleton transformer and Blachly's distribution station. To us, this is a transmission function, not a distribution function, making 34.5 kV a transmission voltage, while 12.5 kV is a distribution voltage.

A similar situation occurs at Minidoka, Idaho. BPA delivers power to the City of Minidoka over a 34.5 kV line that BPA owns, the one remaining 34.5 kV line in the Network segment. The purpose of the line is to move power from generation to the city's load center, which is a transmission function. In this instance, power is moving over BPA's 34.5 kV line to the city's distribution substation and is then transformed to the 2.4 kV distribution voltage. Because Minidoka's load is so small, the most cost-effective way to provide transmission service to Minidoka is over the 34.5 kV line.

A third example is the 34.5 kV system used by Benton REA to move power among its distribution stations. BPA delivers power to Benton at the Alfalfa substation at 34.5 kV. This power is then integrated into the Benton system, where it moves to four Benton substations, where it either is stepped down to distribution voltage or is transferred to the Yakama tribal utility. In addition to this normal operation, switching allows Alfalfa to serve one other distribution substation or serve as emergency feeds to two 115 kV substations. Benton's 34.5 kV facilities operate more like a transmission system than a distribution system, thus BPA's transformer at Alfalfa steps power down from one transmission voltage to another transmission voltage.

Q. How do you respond to the parties' point that they did not cause the need for and do not benefit from these low-voltage facilities?

A. One aspect of a transmission network is that all customers have access to transmission service. All transmission customers are connected directly to BPA's network, regardless of the voltage at which they connect, and use the system in the same way and for generally the same purpose: moving power from generation to load centers. The voltage of the network at the point where a customer happens to connect reveals little about how the customer "uses" the network. A customer connected at 34.5 kV or 69 kV is not connected to and "using" all of the 34.5 kV or 69 kV facilities in BPA's system. Nor is a customer connected at 230 kV connected to and using only 230 kV and higher-voltage facilities. As the term "integration" denotes, an integrated network operates as a single machine to move power in bulk from generation sources to load centers.

For example, the City of Minidoka, mentioned above, has an annual load of 130 average kilowatts (1.14 GWh per year). By the measure of cost causation advanced by the parties, Minidoka, located in southern Idaho, did not cause the need for and does not benefit from any transmission facilities that cross the Cascades or are located west of the Cascades. BPA has relatively few generators west of the Cascades, and none that provides service to Minidoka. The transmission facilities west of the Cascades represent an investment of almost $2 billion, 46 percent of the total Network investment. Yet, because Minidoka receives network transmission service from BPA, it pays its *pro rata* share of all of BPA's Network segment costs, including the many facilities from which Minidoka does not directly benefit. The 17 percent of Network investment that JP12 identified that its members should not pay for because they do not benefit from some facilities pales in comparison to Minidoka's situation. *Id.* at 30. The principle that all users receive benefit in some measure from network facilities is the rationale for utilities charging their users for the entire network rather than trying to pair each transmission facility to its direct beneficiaries.

Q. *For context, how much of the Network segment investment is attributable to BPA's 34.5 and 69 kV facilities?*

A. The 34.5 kV facilities comprise about $20 million of Network investment, or 0.4 percent of the total Network investment of $4.5 billion. Facilities at 46 kV, 57 kV, and 69 kV comprise about $162 million of Network investment, or 3.6 percent of total Network investment.

Q. *JP12 identifies a number of facilities that should be excluded from the Network because they are radial, open loop, local area, or load-serving networks. Please respond.*

A. JP12 has examined BPA's transmission system and tagged a number of facilities with these designations. JP12 argues that most of these facilities (65 percent of the 115 kV and lower-voltage investment) do not perform a network function and should be excluded from the Network segment. But JP12 ignores facilities above 115 kV that perform these same functions simply because they are high-voltage facilities and may be tagged with the Bulk Electric System designation. An examination of all of BPA's facilities would find that a large number of high-voltage, and more expensive, facilities are radial, open loop, local area network, or load-serving networks. Thus, JP12 essentially proposes a bright-line threshold with few exceptions, but drawing the line at 116 kV rather than at 34.5 kV as we propose. However, a number of 230 kV and even some 500 kV facilities perform the same kind of area function, particularly in dense urban areas, as JP12 attributes to more-remote 69/115 kV facilities, yet they are included in the Network segment in JP12's analysis.

For example, in the Seattle area, most of the facilities serving Seattle City Light are constructed at 230 kV because of the amount of load in the area. Some of these facilities are radial or open loop; some are local area networks; and some are load-serving networks. Yet JP12 includes these in the network, seemingly solely because of their voltage. This inclusion underscores the inequity of JP12's proposal to require customers connected at 69 kV and 115 kV to pay the cost of all 230/500 kV facilities, including those performing an area function—since these customers take Network service—while customers connected at 230 kV and higher would have no reciprocal obligation to pay a share of the cost of 69 kV and 115 kV facilities.

Q. What is your rationale for including the 69 kV and 115 kV facilities in the Network segment?

A. As the term "integration" denotes, an integrated network operates as a single machine to move power in bulk from sources to load centers. Transmission planners do not choose the voltage and capacity of particular transmission lines based on one-size-fits-all rules or philosophy for design of a generic transmission system. The purpose of the network is to provide a stable platform by which power can be safely, efficiently, reliably, and cost-effectively moved from bulk power sources to loads and load centers.

Thus, the use of lower voltages to accomplish the transmission network function results from decisions to size facilities based on the amount of load expected to reliably use the facilities; the result is a least-cost transmission system with benefits to all ratepayers. Imposing a rigid definition of the Network, especially one with a higher voltage threshold, may very well result in different decisions on how to serve transmission customers and would most likely increase overall costs.

Q. Please explain.

A. We will use an example from the JP12 testimony. In Exhibit 2, JP12 includes information about the Colville-Republic 115 kV line. JP12 contends that this line provides service to loads on a radial system and therefore benefits only local customers.

Id., Exhibit 2, at 1. This line was constructed at 115 kV because that was the most cost-effective voltage to serve the transmission needs to deliver generation to load centers. Had BPA been constrained to an above-115 kV threshold to qualify this line as a Network facility, it might have constructed the line at 230 kV, increasing the costs of the Network for all users.

The locations of loads and resources and their relative sizes are the primary determinants of the least-cost transmission solutions that result in the best choices of voltage and capacity for each facility. Artificial cost allocation constraints do not make good policy; nor do they deliver transmission to all users in a least-cost manner.

Section 6: The 1996 Transmission Rate Settlement

Q. Please summarize the arguments made by the parties about the 1996 transmission rate settlement.

A. The parties note that BPA adopted the 1996 transmission rates on a non-precedential basis pursuant to a settlement that included a non-precedential segmentation. Holland *et al.*, BP-14-E-JP06-01, at 3, Hanser *et al.*, BP-14-E-JP12-01, at 7, Opatrny, BP-14-E-PX01-E01, at 7. JP12 states that the 1996 settlement agreement does not include any explanation for the parties choosing to revise the Network or Delivery segment definitions. Hanser *et al.*, BP-14-E-JP12-01, at 6. JP12 argues that the definitions established in the settlement agreement should not be the presumptive definitions in this rate case. *Id.* at 7. JP12 asks why BPA Staff does not appear to acknowledge or consider the non-precedential value of the segment definitions. *Id.* at 8.

Q. Please respond.

A. We understand that the 1996 transmission rate settlement was non-precedential with respect to the segmentation used to establish rates under the settlement. However, the fact that a settlement is non-precedential does not restrict a party from making the same proposal in a later rate case. It means only that the party cannot simply cite the past rates as precedent, but instead must provide evidentiary support for its proposal. We did not mention the settlement in the Initial Proposal because we did not rely on it as a rationale for the segmentation we proposed.

Q. *Does this mean that there is no value to any segmentation work done in 1996?*

A. No. BPA Staff did considerable work to prepare the Initial Proposal in the 1996 rate case. We have relied on that work in preparing the segmentation proposal in this case.

Q. *Do you have any other observations about the 1996 settlement?*

A. Yes. One other feature that is common between our Initial Proposal and the 1996 settlement is the elimination of the Northern Intertie segment. In the 1996 Initial Proposal, Staff proposed a Northern Intertie segment that included transmission facilities used to transfer power between the United States and Canada. Under the settlement, BPA eliminated this segment and the Northern Intertie rate. We propose to continue this treatment of no Northern Intertie. None of the parties takes issue with the absence of a Northern Intertie segment in this rate case, even though its elimination was the product of the same settlement that used the 34.5 kV threshold.

Section 7: Bright-Line Threshold versus Functional Analysis

Q. *Please summarize the parties' argument that the Initial Proposal lacks a segmentation analysis.*

A. JP06 states that "BPA does not present a segmentation analysis but rather relies on the non-precedential segmentation from the 1996 BPA rate case. Holland *et al.*, BP-14-E-JP06-01, at 8. Powerex states that "BPA has failed to support its proposed segmentation; instead of providing a detailed segmentation analysis, BPA rate staff has relied exclusively on the segmentation approach from the 1996 Wholesale Power and Transmission Rate Proposal." Opatrny, BP-14-E-PX01-E01, at 7.

Q. Please respond.

A. The accusations that we did not present a segmentation analysis are simply not true. Our analysis is set forth in the Transmission Segmentation Study and its Documentation. The analysis we performed lists each transmission facility BPA owns, the segment or segments to which it is assigned, the total investment in each facility, and the three-year average O&M for each facility. See Study, BP-14-E-BPA-06, and Documentation, BP-14-E-BPA-06A.

Q. The parties claim that you did not perform a functional analysis. Holland et al., BP-14-E-JP06-01, at 10; Hanser et al., BP-14-E-JP12-01, at 13; Arthur, BP-14-E-MS-01, at 26; Opatrny, BP-14-E-PX-E01, at 14-16. Please respond.

A. A functional analysis for segmentation is the examination of each transmission facility to determine how it is used based on any number of factors. Setting aside the intertie and Generation-Integration segments, because they are not at issue here, we reviewed the composition of facilities in the Network and Delivery segments, as modified since 1996 for additions and deletions, and determined that the bright-line criteria we used to assign facilities to the Network segment did not require a functional analysis. The bright-line 34.5 kV criterion used as the threshold between Network and Delivery was still appropriate. This is further explained below.

Q. What is the parties' principal concern?

A. Their principal concern is our use of a bright-line threshold to differentiate between the Network and Delivery segments. They argue that the bright line inappropriately includes in the Network segment facilities that do not perform network transmission functions. Hanser *et al*., BP-14-E-JP12-01, at 8. JP12 argues that the bright-line voltage definition cannot confirm that the Network segment will include only facilities that serve a transmission function and that the Delivery segment will include all of the distribution-like facilities. *Id*.

Q. *What functional test do the parties propose?*

A. JP12 proposes two functional tests used by the Federal Energy Regulatory Commission (Commission), the Seven Factor Test and the test for including facilities in the Bulk Electric System. *Id*. at 22.

Q. *What is the Commission's Seven Factor Test?*

A. JP12 adequately describes the Seven Factor Test in its testimony. *Id*. at 22-23. Stated simply, it is a jurisdictional test that applies to public utilities under the Federal Power Act that determines whether facilities serve a transmission function (subject to the Commission's jurisdiction) or distribution function (subject to state jurisdiction).

Q. *Is BPA required to apply the Commission's Seven Factor Test to determine how its facilities are segmented?*

A. No. BPA is a non-jurisdictional utility under the Federal Power Act. Therefore, the Commission's ratemaking policies applicable to jurisdictional utilities are not binding on BPA. Rather, the Commission's review of BPA's rates is limited to the criteria set forth in section 7(a) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839e(a)(2). With respect to the Seven Factor Test specifically, we also note that none of BPA's transmission facilities or associated rates is subject to state jurisdiction. Therefore, the reason for applying the Seven Factor Test—to determine the split between Federal and state jurisdiction—does not apply to BPA.

Q. *Do you have any general observations about how the Seven Factor Test might be applied if you used it in a segmentation analysis?*

A. While BPA is not required to perform the Seven Factor Test and we do not concede that JP12 applied the Seven Factor Test to BPA's system appropriately, we note that JP12 admits it did not apply factors 4 and 6. *Id*. at 32-33. Those two factors would be the most damning to JP12's position if included in its analysis. Under Factor 4—when power enters a local distribution system, it is not reconsigned or transported on to some other market—almost all of BPA's facilities would be considered transmission and included in the Network segment. Ninety-four percent of BPA's power sold under the Priority Firm Power (PF) and Industrial Firm Power (IP) rates is reconsigned (or sales for resale); that is, it is sold to an entity intervening between BPA and the ultimate end-user. That intervening entity, the local retail utility, then resells the power to the end-user. Of the remaining six percent of power sales that is not reconsigned, most is delivered at 230 kV, leaving 0.7 percent of the power BPA sells delivered using the facilities that JP12 would remove from the Network segment.

Furthermore, under Factor 6—meters are based at the transmission/local distribution interface to measure flows into the local distribution system—BPA facilities again would be considered transmission assets and included in the Network segment. At every point of delivery, whether at higher or lower voltages, BPA meters the transfer of power to the retail utility. Because the power on BPA's system is transferred to other entities, BPA needs meters to measure amounts of power for billing purposes. The Seven Factor Test recognizes that the delivery of power from generator to load does not require intervening metering anywhere on the transmission and distribution systems, except when transmission is being used by others and must be measured for billing purposes.

Q. *Is the use of a bright-line threshold incompatible with the Commission's Seven Factor Test?*

A. No. We believe that a common usage of the Seven Factor Test among jurisdictional utilities is to distinguish which groups of facilities are in the transmission function and which are in the distribution function, rather than applying the test to individual facilities. For example, Puget Sound Energy (Puget) recently used the Commission's Seven Factor Test to move all of its 55 kV facilities from distribution to transmission. It is our observation that utilities generally deal with facilities grouped by voltage rather than with individual lines and stations. Only in isolated instances in which a particular facility is so different from the voltage group does an facility-specific test apply.

For example, Portland General Electric (PGE) has a significant number of 57 kV facilities. Almost all of them serve a distribution function. However, a few 57 kV facilities are associated with generating projects and serve a transmission function. Therefore, PGE assigns these few facilities to transmission and the rest to distribution. Although we are not experts on the operational details of Puget's and PGE's systems, it seems unlikely that Puget's use of its 55 kV lines differs significantly from PGE's use of its 57 kV lines. It is more likely that these lines operate similarly in conjunction with higher-voltage facilities and distribution facilities. But Puget found that its 55 kV facilities were more appropriately included in the transmission function, while PGE found that its 57 kV facilities were more appropriately included in the distribution function. We expect that if the Seven Factor Test were to be done on each facility separately, some of each utility's facilities would end up in different functions, especially considering that a portion of PGE's 57 kV facilities are providing transmission for BPA's power sale to Canby, yet PGE has put these facilities into their distribution function. The usual resolution that we have observed when Northwest utilities have applied the Seven

Factor Test is to use the predominant use for each group of facilities, recognizing that there is rarely certainty or perfect consistency in the result: Puget answered that the predominant use is transmission, whereas PGE answered that it is distribution. We would answer, with respect to BPA's lower voltages, that BPA's 34.5 kV facilities operate predominantly as transmission.

Q. *Can you give examples of how BPA's 34.5 kV facilities operate predominantly as transmission facilities?*

A. Yes. Earlier, we gave the examples at Mapleton, Minidoka, and Alfalfa. In addition to these, we looked at two other utilities (Flathead and Lane) that are served with 34.5 kV facilities. PNGC did a similar analysis of its members with 34.5 kV facilities (Flathead, Lane, Clearwater, Northern Lights, Blachly-Lane, West Oregon, and Raft River). See Supplemental Response to Data Request No. BPA-JP03-6 (Attachment 1 to this testimony). Altogether, the 34.5 kV facilities serving these utilities comprise 83 percent of the total 34.5 kV investment ($56 million out of $67 million). In each situation, BPA's 34.5 kV facilities transfer power to the local retail utility to transmit over their 34.5 kV transmission lines from BPA's stations to their own distribution stations. For example, Lane Electric's 34.5 kV system connects to BPA at Alvey, Eugene, and Dorena and is used to feed five distribution stations on Lane's system, and depending on switching, can tie the BPA delivery points together. Another example is Flathead Electric, whose 34.5 kV system connects to BPA at Columbia Falls, Kalispell, Lion Mountain, and Flathead (at the latter two stations, Flathead owns the transformers). Flathead's transmission system is used to feed 15 distribution stations, and, depending on switching, can tie the BPA delivery points together.

Q. Because you did not examine every 34.5 kV facility, does this mean that it is possible that some of the 34.5 kV facilities might be segmented as Delivery if you did a functional test for each facility?

A. Yes. However, as stated above, all of BPA's 34.5 kV facilities fail factors 4 and 6, so segmenting any of them as Delivery would require a judgment that other factors were more important than these two. It is equally likely that some facilities currently included in Delivery might be segmented to Network under the same examination. We did not claim that the bright-line threshold was perfect, just that it was predominately correct and that the cost consequences of the potential differences are insignificant.

Section 8: Use of Power Flows in Segmentation Functional Analysis

Q. JP12 compares Response to Data Request No. PG-BPA-4, which says that power flow results have not been generally used in past segmentation, to prior segmentation studies and testimony from the 1985, 1987, 1991, and 1993 rate cases. Hanser et al., BP-14-E-JP12-01, at 11-12. JP12 argues that the testimony presented in those cases refutes the answer in the Response. Id. Is JP12 correct?

A. No. As explained in the Response, the prior rate case statements that JP12 cites regarding the use of power flow studies in segmentation were meant to be read generally. A typical statement in prior rate cases was "[e]ach facility is analyzed using the system one-line diagrams in conjunction with the power flow studies to assign it to the proper segment." 1987 Segmentation Study, WP-87-FS-BPA-02, at 8. Power flow studies were not the only tool that was used to segment each facility. Rather, power flow studies were among the tools used in segmentation as one source of information and were primarily used at that time to determine the operating voltages and ownership of various facilities, not for direction of flow. Therefore, we draw a distinction between "power flow studies" as a source of information and "power flow study results," which are the direction and magnitude of power flows. The study results were generally not used because they represented limited circumstances of direction and magnitude of power flows. Instead, meter data was used to determine flow direction and magnitude when needed. Meter data is more encompassing of all operating conditions, whereas power flow study results are confined to a few cases and limited conditions that are modeled and are dependent on the availability and assumptions of the studies. The prior studies did not mention meter data as a source of information because it too was rarely used.

Q. Which do you consider the most important factor of those used prior to 1996?

A. The most important factor was the contracts. The need to distinguish between the Network and the Fringe was the most difficult part of the pre-1996 segmentation analyses. Contract data, such as sources of generation and points of delivery, was much more useful to distinguish whether non-Federal power was being delivered to a given customer. For the determination of ownership of delivered power, power flow studies would have been of no assistance. For example, the lines serving Grays Harbor and Pacific counties in Washington were in the Fringe segment. Power flow studies, operating under the laws of physics instead of contract paths, would most likely have shown a significant amount of non-Federal generation from Centralia serving these two counties. Reliance on power flow studies to determine whether Federal or non-Federal power was using the lines to the two counties would have not resulted in a Fringe segmentation for these lines.

Q. What is the importance of whether or not power flow study results were used?

A. The importance is in the conclusion that JP12 draws from its position on the use of power flow studies. JP12 argues that if BPA did not use power flow studies, then the facilities included in the Network and Delivery segments after 1996 should be the same facilities included before 1996. *Id.* at 12-13. JP12 asserts that there is no indication that the function of the facilities included in the Network and Delivery segments before 1996 changed after 1996. *Id.* at 13-14. JP12 claims that the only factor that appears to be making a difference is the consideration of power flow studies before 1996. *Id.* at 13.

Q. Do you agree with this conclusion?

A. No. The changes in segmentation introduced in 1996 were not premised on a change in power flow or function. The major change, as discussed above, is that BPA was unbundling its transmission service and changing to a paradigm that treated all customers, power and wheeling, as transmission customers and transmission contract holders paying tariff-based rates.

JP12 notes that before 1996 the facilities in the Delivery segment were facilities with voltages from 12 kV to 69 kV; the Network segment consisted of facilities with voltages from 115 kV to 500 kV plus a few 69 kV facilities. *Id.* at 13. This result came about because the pre-1996 Network segment included facilities used to provide services for both Federal power sales and wheeling of non-Federal power, based on sources of power supply. Beginning in 1996, the distinction between Federal power and non-Federal power no longer mattered for purposes of segmentation. Customers were diversifying their power sources, and more non-Federal power was now utilizing transmission facilities that previously were segmented to the Fringe segment.

For example, compare the cases of the City of Milton-Freewater and Columbia Basin Electric Co-op. Both utilities are served by 69 kV lines. Milton-Freewater wheels power from Priest Rapids and Wanapum Dams to its load center. Therefore, the 69 kV lines serving Milton-Freewater were segmented to the Network segment before 1996. Contrast this segmentation to that of Columbia Basin's service lines. Columbia Basin was in a situation similar to that of Milton-Freewater, receiving service at Fossil by a

69 kV line and Ione by a different 69 kV line. The sole distinction between Milton-Freewater and Columbia Basin was that Columbia Basin's sole source of power prior to 1996 was Federal generation, while Milton-Freewater power sources were a mix of Federal and non-Federal generation. Thus, the 69 kV line serving Milton-Freewater was included in the Network segment because it was wheeling non-Federal power, while the two lines serving Columbia Basin were excluded from the Network segment solely on the basis of the source of the power being Federal generation.

Before 1996, the segment choices for the 69 kV Fossil and Ione lines were Fringe or Delivery segments. The choice prior to 1996 was to segment both lines into the Fringe segment and include their costs in bundled power rates. Beginning in 1996, segmenting these three 69 kV lines differently based solely on whether they were used to deliver Federal or non-Federal power was no longer considered a valid criterion. Therefore, all these lines were rolled into the Network segment in 1996 because they were all used to perform a transmission function. The primary segmentation question was no longer the source of the power serving the customer but which facilities provide transmission services to the customer. In this rate case, after examining the facilities in the marginal voltages (12 kV to 69 kV), we reconfirmed that 34.5 kV is the appropriate voltage to use as a bright-line threshold.

Section 9: Equitable Cost Allocation

Q. Please summarize the parties' arguments regarding equitable allocation of transmission costs.

A. JP06 argues that by relying on an arbitrary bright-line voltage threshold, BPA will not be able to demonstrate an equitable allocation of transmission costs. Holland *et al.*, BP-14-E-JP06-01, at 17. JP12 argues that including non-Network facilities in the Network segment is inconsistent with equitable cost allocation. Hanser *et al*., BP-14-E-JP12-01, at 20. Powerex argues that we have not shown that our proposed segmentation results in equitable allocation between Federal and non-Federal users of the system. Opatrny, BP-14-E-PX01-E01, at 14.

Q. Please explain your understanding of equitable allocation.

A. We cannot provide a legal analysis of statutory requirements, but our duties require us to understand and implement various statutory directives. The directive to equitably allocate arises out of section 10 of the Transmission System Act, which provides

> The … schedules of rates and charges for transmission, the said schedules of rates and charges for the sale of electric power, or both such schedules, may provide, among other things, for uniform rates or rates uniform throughout prescribed transmission areas. The recovery of *the cost of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing such system*.

16 U.S.C. 838h (emphasis added). The language was reiterated in section 7 of the Northwest Power Act:

> Rates established under this section shall become effective only, except in the case of interim rules as provided in subsection (i)(6) of this section, upon confirmation and approval by the Federal Energy Regulatory Commission upon a finding by the Commission, that such rates … insofar as transmission rates are concerned, *equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system*.

16 U.S.C. 839e(a)(2) (emphasis added). To us, this standard means that transmission rates should not favor either Federal or non-Federal power. We believe that if rates for Federal power were more favorable than rates for non-Federal power, they would fail the equitable allocation test. The converse is also true: if transmission rates for non-Federal power were more favorable than transmission rates for Federal power, they would fail the equitable allocation test.

Q. How have you implemented equitable allocation in this rate proposal?

A. All transmission service, whether for Federal or non-Federal power, pays the same rates for the same service. We believe, based on our understanding of these statutory directives, that neither Federal nor non-Federal power is advantaged if both pay the same rates.

Q. How does segmentation play a role in equitable allocation?

A. Before 1996, it played an important role. Transmission costs assigned to Federal power were recovered in bundled power rates. Transmission costs assigned to non-Federal power were recovered through transmission rates. Thus, Federal and non-Federal power paid different rates, and it was important to ensure equitable allocation through segmentation and allocation.

As we described earlier, beginning in 1996, conditions in the electric utility industry changed. Unbundled power rates, open access transmission, and comparability resulted from national policies intended to ensure that transmission providers charged other users of their systems the same rates they charged themselves. BPA implemented this policy by removing transmission costs from power rates, signing open access transmission contracts with power customers, and charging all users the same rates for transmission service.

With these changes, the focus of segmentation changed from identifying the Network segment based on facilities that were used by both Federal and non-Federal power to a Network segment based on the facilities necessary to provide transmission service to all customers.

Q. *To what extent do public power customers move non-Federal power using lower-voltage facilities that are in the Network and Delivery segments?*

A. Our analysis shows that 73 out of 133 customers, 55 percent, are taking some amount of non-Federal power to load. The breakdown of source of power by aggregated customers and points of delivery segregated by delivery voltage is:

	Delivery		**Network**							
	POD voltage < 34.5 kV		**POD voltage 34.5-46 kV**		**POD voltage 50-69 kV**		**POD voltage 100-115 kV**		**POD voltage 120-500 kV**	
	# cust.	**# POD**	**# cust.**	**# POD**	**# cust.**	**# POD**	**# cust.**	**# POD**	**# cust.**	**# POD**
Fed + non-Fed power	28	92	18	31	26	60	53	266	20	45
Fed power only	34	47	2	3	10	29	26	57	10	11
total cust. & POD	62	139	20	34	36	89	79	323	30	56
pctg Fed + non-Fed	45%	66%	90%	91%	72%	67%	67%	82%	67%	80%

Excludes Seattle City Light and Tacoma Power because power is delivered to their BAs, not PODs.
Includes only two PODs each for Okanagan PUD and Grant PUD that are in BPA's BA.

This analysis shows that across all voltage levels, BPA's public power customers are using the transmission system to diversify by using more non-Federal power to serve their loads, and to a greater extent than occurred prior to 1996. Especially significant is that the analysis shows that 90 percent of BPA's customers that have 34.5 kV points of delivery are receiving a mixture of Federal and non-Federal power.

Q. *Is there a particular reason that power customers that are taking only Federal power should pay the same transmission rates as customers taking a mix of Federal and non-Federal power, or transmission customers that are not purchasing any Federal power?*

A. Yes. As discussed above, the transmission rates should not favor or disadvantage any particular source of power. BPA has gone as far as introducing this same construct into its power rates through its Tiered Rate Methodology. Generally, any sources of power that have melded older and cheaper generators with newer and more expensive generators will have a cost advantage when competing for sales with new generators. This is particularly true for BPA, where the bulk of the power is sourced from older hydroelectric projects. By continuing to meld new generation sources with its hydro base, BPA could continually beat the long-term supply cost of a new power market entrant. With tiered power rates, BPA charges the costs of its legacy power supply (hydro and nuclear) to customers at one tier and the cost of new sources of power at a second tier. This puts BPA's power supply to new loads at a competitive neutral position with new generation sources. Thus, all else being equal, the supplier that can supply new generation at the lowest rates, without the benefit of melding legacy generation, will make more sales. Implementing a transmission rate structure based on power supply source would upset the competitive balance for some parties compared to others.

This same premise holds true at the retail utility level. When local areas are competing for new businesses and industries to locate in their area, power costs are often a primary consideration. In many circumstances, rural communities have distinct disadvantages in attracting new companies to their areas due to their location being distant from larger markets. JP12's proposal would make these disadvantages even worse by charging the local utilities more just because they are smaller (lower voltage) and more distant (radial lines).

Section 10: Bulk Electric System

Q. Please summarize the parties' arguments about the Bulk Electric System (BES).

A. JP12 proposes that the BES is an appropriate starting point for determining the facilities that should be included in the Network segment. Hanser *et al*., BP-14-E-JP12-01, at 24. JP12 proposes that if a facility is in the BES, it should be included in the Network segment; if it is not in the BES, it should excluded from the Network segment. *Id*. at 26.

Q. *What are the differences between transmission, distribution, and the BES?*

A. Transmission facilities are efficient at moving large amounts of wholesale power over long distances, but transmission facilities generally cost more to build than distribution facilities and are not as cost-effective over shorter distances or for smaller amounts of power. Distribution facilities can most efficiently and cost effectively transmit smaller amounts of power, such as through a single neighborhood, in the amount and at the voltage more suited to retail consumer needs. Distribution facilities perform this local power delivery function most efficiently because they have been designed to do so, one characteristic of that design being a lower voltage than is typical at the transmission level.

BES is composed of transmission equipment—distribution equipment does not move amounts of power that might be considered "bulk" in any sense. The factor that distinguishes a bulk electrical system from simply being a collection of transmission-voltage facilities is that the BES provides the means to achieve and maintain the precise synchronization of interconnected generators over a wide area. Only lines of a sufficient size and capacity can tie generators together so that all of the operating units will remain within stability limits, ensuring system reliability.

BES facilities ensure interconnected security, which is the ability to maintain synchronization of generators, under a range of conditions. The overarching goal in BES planning is to ensure that, given a standard threshold, no set of events compromises the ability of interconnected generators to sense and adjust to changes in surrounding frequency so that the system remains stable and interconnected security is preserved.

Q. *The term "local distribution" is used in the description of the BES. Hanser et al., BP-14-E-JP12-01, at 24. What is your understanding of this term?*

A. The BES term "local distribution" arises from section 215 of the Federal Power Act, 16 U.S.C. 824o. However, we do not understand "local distribution" in a BES context to be precisely the same as “local distribution” as used in the Commission’s Seven Factor Test. We base this distinction on the fact that the Commission sets a 100 kV threshold between BES and local distribution despite the fact that most jurisdictional utilities in the Pacific Northwest have applied the Seven Factor Test and established a lower voltage threshold between transmission and distribution.

Q. What evidence do you have of this distinction?

A. We note that section 215 became law in 2005 and is the subject of Commission Order Nos. 693 (2007), 694-A (2007), 729 (2009), 729-A (2009), 729-B (2010), 743 (2010), 743-A (2011), and 773 (2012). At no time since 2005 has the Commission undertaken any effort to conform either the Seven Factor Test or utility applications of the Seven Factor Test with the definition of the BES. Neither has the Commission disclaimed jurisdiction over non-BES facilities in ratemaking settings. The Commission has stated it would apply the Seven Factor Test to resolve questions of whether a facility is BES or not, but we do not know of any situation where such an application was made.

Within the region, Puget Sound Energy applied the Commission’s Seven Factor Test in 2012, which resulted in a 55 kV threshold between transmission and distribution. This determination occurred after the Commission issued orders setting the BES threshold at 100 kV. In addition, PacifiCorp set a threshold between transmission and distribution by including 46 kV in transmission; Idaho puts 46 kV in transmission; and Northwestern puts 50 kV in transmission.

We read JP12’s testimony as confusing the distinction between local distribution as used in the BES construct to define facilities that provide reliability functions and local distribution as used to determine jurisdiction.

Q. Please summarize your findings about Commission rate policy as it relates to the BES.

A. The Commission has not used the BES definitions for ratemaking purposes. The advent of the BES construct in 2005 has not changed the Commission's policy regarding the costs that should be included in the rolled-in rate for service on an integrated transmission system despite a number of opportunities. More specifically, the Commission has not created a new rate design paradigm whereby it is acceptable to charge only the costs of BES facilities to all customers on the system while the costs of non-BES transmission facilities are, in effect, directly assigned to the customers connected to them notwithstanding the facilities' participation in bulk power transfers and contribution to system reliability. The fact that lower-voltage transmission facilities may not be BES facilities does not alter the facts that (1) they are integrated with higher-voltage transmission facilities and (2) they contribute to the transfer of bulk power and support the reliability of the integrated system.

Section 11: 2008 ASCM Functionalization and the Puget 55 kV Roll-in

Q. Please summarize the parties' arguments regarding the alleged discrepancy in BPA policy between segmentation and the Average System Cost Methodology (ASCM).

A. The parties allege that the ASCM requires a bright-line 115 kV threshold between transmission and distribution. Hanser *et al.*, BP-14-E-JP12, at 12; Holland *et al*., BP-14-E-JP06-01, at 12, Opatrny, BP-14-E-PX01-E01, at 22. The parties argue that it is inconsistent for BPA to mandate a 115 kV threshold for ASCM purposes and use a 34.5 kV threshold for segmentation.

Q. Do the parties correctly characterize the ASCM?

A. No. The portion of the ASCM that the parties cite is Endnote i to Appendix 1. Appendix 1 is the form used by utilities to file the information needed by BPA to determine the utility's Average System Cost (ASC). Endnote i states:

> If a Utility has a ruling from its Regulatory Body that separates its transmission and distribution lines using FERC's seven factor test contained in Order 888, and its Form 1 filing is consistent with the Regulatory Body's order, the Utility will include the transmission-related costs and wheeling revenues directly from its Form 1 filing. However, if a Utility is not required to file a Form 1, or it has not received an order from its Regulatory Body separating its lines between transmission and distribution, then it must perform a Direct Analysis on its transmission costs and wheeling revenues. The Direct Analysis must allocate transmission costs and wheeling revenues so that only the costs and revenues of transmission lines rated at 115 kV or above are included as transmission. Alternatively, the Direct Analysis may use FERC's seven factor test for separating transmission and distribution lines to determine the costs attributable to transmission.

2008 ASCM Record of Decision (ROD), Attachment A at 27. The Endnote states that if the filing utility has met certain conditions, BPA will accept the utility's determination of how to divide transmission from distribution on its system. Only if a filing utility has not performed the required separation of transmission and distribution does the 115 kV threshold govern―the ASCM requirement is only a backstop. If the utility does the separation itself, however, there is no voltage standard. BPA allows the utility and its regulators to choose the appropriate distinction between transmission and distribution.

In practice, the utilities that file ASCs have largely adopted segmentations that fall below the 115kV backstop. The following chart summarizes the transmission threshold voltage levels used by utilities in their ASC filings for the FY 2014–15 exchange period.

Utility	Threshold
Avista	60 kV
Idaho	46 kV
Northwestern	50 kV
PacifiCorp	46 kV
Portland General	115 kV *
Puget 2011 *	230 kV
Puget 2012 *	55 kV
Clark	69 kV
Snohomish *	115 kV

* PGE includes a small portion of generation-related 57 kV facilities
* Prior to 2012, some of Puget's 115 kV facilities were transmission and some were distribution. This delineation is included in Puget's ASC filing for FY 2014-2015 (One 115 kV line was included in transmission). In 2012, Puget's threshold for network facilities changed from 230 kV to 55 kV. We expect this delineation to be included in Puget's ASC filing for FY 2016-2017.
* Snohomish has no facilities between 115 kV and 12.5 kV.

As can be seen, the vast majority of utilities segment their systems below 115 kV. With Puget's recent reclassification of its facilities, only PGE and Snohomish use 115 kV as the transmission-distribution threshold in their ASC filings. All others are significantly lower than 115 kV and are closer to BPA's 34.5 kV threshold than to JP12's proposed 116 kV threshold. Coupled with the fact that BPA's Network investment below 69 kV is only about 0.5 percent of total Network investment, there is little distinction and almost no consequence to any differences between our proposed 34.5 kV threshold and the thresholds of most of the ASC filing utilities.

Q. Did any party raise an issue about the use of a 115 kV backstop threshold during the development of the ASCM?

A. No. The 115 kV backstop threshold was not raised as an issue despite much discussion about the inclusion of transmission costs in ASC determinations. The ASCM ROD is virtually silent on the threshold question. However, the effect of setting the backstop voltage level in Endnote i to 115kV is to give utilities an incentive to perform their own separation. Under the ASCM, facilities functionalized to the transmission segment may be included as a cost in the utilities' ASCs. Facilities functionalized to the distribution segment, however, are excluded from a utility's ASC. Fewer facilities in a utility's transmission segment means fewer costs in a utility's ASC, which, in turn, translates into lower payments under the Residential Exchange Program (REP). The ASCM's use of 115 kV as the backstop separation—a voltage level that was substantially above BPA's own 34.5 kV segmentation at the time of the ASCM's development—would allow fewer transmission costs in a utility's ASC (thus reducing REP payments). Therefore, utilities wanting greater REP payments have an incentive to perform separations with their commissions to determine whether the costs of additional transmission facilities may be included in their ASCs.

Q. The parties also argue that your proposed 34.5 kV bright-line threshold is inconsistent with positions that BPA took in Puget's proposals to assign 55 kV facilities as network or distribution. Hanser et al., BP-14-E-JP12-01, at 16-17; Opatrny, BP-14-E-PX01-E01, at 24. Please respond.

A. JP12 cites two Puget cases in which BPA filed interventions and protests. The first was in 2002 when Puget proposed to remove all of its 55 kV and most 115 kV facilities from its transmission function. The second was in 2012 when Puget proposed to move these facilities back into its transmission function. Powerex cites the latter case. *Id*. at 24.

The parties' arguments ignore the context of the protests. In the first case, Puget was proposing to remove its 55 kV and most 115 kV facilities from its network primarily to keep them from being placed under the control of the regional transmission organization (RTO) that was being considered at that time. In its protest, BPA was concerned that facilities that might be important for regional transmission use and control were being excluded from the RTO in a preemptive move without any examination of these facilities. Even assuming that this case is relevant to segmentation, BPA's position in the case was the same as our position here. BPA was arguing that certain lower-voltage facilities should remain in Puget's transmission function.

In the second Puget case, BPA protested the lack of details in Puget's proposal to move its 115 kV and 55 kV facilities back into the transmission function. BPA was concerned that Puget had not provided enough information supporting the appropriateness of the facility shift.

Q. What was the result of the two Puget cases?

A. The 2001 case was resolved with Puget being allowed to remove its 115 kV and 55 kV facilities from its transmission function. The 2012 case ended with a settlement that allowed Puget to return its 115 kV and 55 kV facilities to its transmission function. BPA did not oppose this reclassification in the settlement.

Q. Did Puget do the type of functional test that the parties argue BPA should do?

A. Puget applied the Commission's Seven Factor Test and ended up with mostly a bright-line voltage threshold. All of Puget's facilities of 55 kV and above were designated as transmission, with the exception of one radial substation. Puget did not further separate these transmission facilities for ratemaking purposes; the costs of the 55 kV facilities were rolled into its network transmission rate.

Q. Powerex states that the use of a bright-line threshold might be an appropriate place to start a segmentation analysis, but that it should then be accompanied by a technical analysis to determine the function of each facility. Opatrny, BP-14-E-PX01-E01, at 14. Please comment.

A. Observing the results of the investor-owned utilities that are required to apply the Seven Factor Test, the Test more often results in a bright-line threshold rather than facilities at the same voltage being in different functions, as Powerex's proposal implies. We see very few instances in the Northwest where the Seven Factor Test has resulted in a significant portion of a utility's facilities ending up in one function and a significant portion of facilities at the same voltage in another function.

Section 12: National Policy on Transmission Ratesetting

Q. Have you reviewed national policy on network transmission ratemaking?

A. Yes. We have examined several cases before the Commission to explore how the parties' position compares with the Commission's direction in determining the facilities included in network transmission rates.

Q. What have you found?

A. The Commission has a longstanding policy that strongly favors rolled-in transmission rates. See, for example, *California Dept. of Water Resources v. FERC*, 489 F.3d 1029, 1037-38 (9th Cir. 2007) ("FERC precedent clearly demonstrates a consistent policy favoring the rolled-in method of transmission pricing where the system operates as an integrated whole.").

Q. What is meant by "rolled-in"?

A. The Commission uses the term "rolled-in" to mean the inclusion of all transmission facilities in a utility's network transmission rates except in limited cases that exclude specific facilities.

Q. Why does the Commission favor rolled-in pricing?

A. The Commission states that rolling in transmission costs results in the most cost-efficient and reliable transmission grid benefitting all users of the grid:

> The principal reason behind adoption of this methodology is that an integrated system is designed to achieve maximum efficiency and reliability at a minimum cost on a systemwide basis. Implicit in this theory is the assumption that all customers, whether they be

> wholesale, retail or wheeling customers, receive the benefits that are inherent in such an integrated system.

Otter Tail Power Co., 12 F.E.R.C. ¶ 61,169, 61,420 (1980).

Q. *Have you found any policies about charging costs of a subset of facilities solely to those customers that use those facilities?*

A. Yes. The Commission's policies are well summarized in the following conclusion by an Administrative Law Judge (ALJ):

> The Commission's policy requiring a single rolled-in rate for transmission service on an integrated system is consistent with the cost causation principle found in *Illinois Commerce Commission v. FERC* [fn: 576 F.3d 470, 477 (7th Cir. 2009)]. The Commission does not "ha[ve] to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars," but it must "ha[ve] an articulable and plausible reason to believe that the benefits are at least roughly commensurate with" the customers' causation of the cost incurrence. [fn: *Id*. (citations omitted).] When considering cost allocation on an integrated system, "the Commission treats each transmission customer not as using a single transmission path but rather as using the entire transmission system." [fn: *N. States Power Co. (Minn.) v. FERC*, 30 F.3d 177, 179 (D.C. Cir. 1994)] Accordingly, particular components of an integrated transmission system do not have to be allocated to particular transmission customers, or classes of customers, in proportion to their direct use, or degree of direct benefit, because such disaggregating and balkanizing is inconsistent with the operation of an integrated system as a single machine.

Buckeye Power, Inc. v. Am. Transmission Sys., Inc., Initial Decision, 142 F.E.R.C. ¶ 63,007, January 11, 2013, 2013 WL 240892 (F.E.R.C.) at 238. *Buckeye* involved examining American Transmission System's voltage-differentiated rates: one rate for 138 kV and above, and a separate rate for 69 kV facilities. The ALJ ruled that the 69 kV facilities should be rolled in with the higher-voltage facilities, resulting in a single network rate.

Q. *Have you found any basis for summarizing how you believe the parties' proposal would be measured against national ratemaking policy?*

A. Yes. We found the following statement in a filing to the Commission:

> Allowing transmission customers to cherry-pick facilities out of a utility's integrated system for segmented rates would result in an ever-shrinking network of rolled-in facilities, and ultimately result in a proliferation of rate pancakes. Such an outcome would be inconsistent with "the Commission's long-standing preference for rolled-in pricing of transmission facilities" in an integrated network. "Recognizing that the grid is a cohesive network in a dynamic state of development, the Commission has even included remote facilities in the grid on the grounds that they were merely the first segment of what would eventually be a network loop." This preference is grounded in the public policy rationale that "an integrated system is designed to achieve maximum efficiency and reliability at a minimum cost on a system-wide basis. Implicit in this theory is the assumption that all customers, whether they be wholesale, retail or wheeling customers, receive the benefits that are inherent in such an integrated system" and therefore "all customers should share in all costs of the integrated grid …"

Answer of Puget Sound Energy, Inc. in Opposition to the Motion for Leave to Answer of Vantage Wind Energy LLC, Docket No. ER12-778-000, March 1, 2012, at 6-7 (citations omitted).

Q. Even though BPA is a non-jurisdictional utility and, therefore, not subject to national ratemaking policy applicable to jurisdictional utilities, do you believe that your Initial Proposal segmentation results in benefits that are at least roughly commensurate with cost causation?

A. Yes. All transmission customers are receiving comparable network transmission services; that makes them comparable. The fact that some customers receive services at higher voltages and some at lower voltages is more a reflection of the relative size and location of the customers' load service area than a measure of the service that each receives. The fact that parts of Snohomish County are highly urbanized, which dictates having in place a large number of 230 kV and 500 kV transmission lines, is no more reflective of the transmission service Snohomish PUD receives than is the fact that Ferry County, because of its remote location and size of load, sits at the end of a radial 115 kV line, and the City of Minidoka, a very small utility in Southern Idaho, is most cost-effectively served using a 34.5 kV line.

We view the service to these small remote customers at differing voltages as more a reflection of the provision of service on a least-cost basis than a reflection of the type and quality of service provided to each customer.

Section 13: Cost Recovery

Q. Please summarize the parties' testimony on how they would recover the costs of the facilities that they would exclude from the Network segment.

A. JP06 is silent on how such costs would be recovered. In discovery, the JP06 parties clarified that they would leave it to BPA to propose a cost recovery mechanism other than network transmission rates. Response to Data Request No. BPA-JP06-1 (Attachment 2 to this testimony). JP12 also does not propose a specific cost recovery mechanism but suggests that BPA should seek to recover the costs from the customers that use and benefit from these particular facilities. Hanser *et al.,* BP-14-E-BPA-JP12, at 36. JP12 and Powerex suggest that the facilities that serve "distribution-like" functions should either be included in the Utility Delivery segment or in a new segment whose costs are assigned to those customers that cause them to be incurred and/or benefit from their incurrence. *Id.*; Opatrny, BP-14-E-PX01-E01, at 8.

Q. Do you agree with the parties' proposal to segment lower voltage-transmission costs to the Delivery segment or otherwise charge only those users that are directly connected to such facilities?

A. No. Customers are using BPA's network segment to integrate their resources and loads in the same manner and are similarly situated regardless of delivery voltage.

Q. What concerns does the parties' proposal raise?

A. In addition to their proposal being counter to BPA's longstanding policy regarding uniform transmission rates, the proposal contains some errors and raises questions about fairness, competitive advantage, and the treatment of General Transfer Agreement costs.

Q. Please give an example of the errors in the JP12 proposal.

A. JP12 designated a portion of the Red Mountain substation as Network with none of the interconnecting transmission lines designated as Network, resulting in an islanded portion of the Network segment. In a data response, JP12 acknowledged that none of this substation should be allocated to the Network. See Response to Data Request No. BPA-JP12-5, Attachment 3 to this testimony. In addition, there were several cases in which JP12 was unable to match power flow results with the segmentation study and one-line diagram nomenclature. *See, generally,* BP-14-E-BPA-JP12, Attachment 3, lines marked with "No Data" and similar notations.

JP12 also had duplicate entries for the Boardman substation. Removing the duplication reduces JP12's calculation of non-Network investment by $6.8 million and reduces O&M by $104,000.

Q. Please explain your concern about fairness.

A. For any particular customer, BPA determines what lines to build based on the engineering and economic considerations that will lead to maximum efficiency and reliability at minimum cost on a system-wide basis. Therefore, it would be unfair for BPA to charge more to customers where BPA, not the customer, has determined that lower-voltage service was more cost-effective than higher-voltage service or that a radial line was more cost-effective than a looped network. We do not believe that it is appropriate that segmentation policy should influence planning and construction design decisions. Having a separate treatment for facilities below 116 kV as JP12 advocates would put customers in the position of arguing for BPA to build facilities at voltages above 115 kV simply because of the rate consequence.

For example, as discussed above, Ferry County PUD is served using a 115 kV radial line from Colville to Republic. Currently, each year, the city of Republic goes one day without any service so that maintenance can be performed on its radial line. If JP12's bright-line 116 kV threshold and exclusion of radial lines were used as segmentation criteria, not only would Republic face complete lack of service at times, but the city would pay more for that privilege. Ferry County would likely begin advocating that the existing line be upgraded to 230 kV from Addy to Republic, and that a new line from Republic to East Omak be added to escape the annual outage and the new, higher transmission charge. If BPA were to upgrade its system in this manner, all transmission customers using the Network would share in the costs of that upgrade.

Q. Please explain your concern about competitive advantage.

A. All of BPA's customers have choices of power suppliers. Under BPA's tiered rate construct, BPA serves a base amount of a power customer's load at a first tier rate, and the customer can purchase amounts above the base level from BPA at a second tier rate or from non-Federal suppliers or can construct or contract for their own resources. In setting up this construct, BPA has tried to create a level playing field so that BPA neither advantages nor disadvantages the customer's choices in serving its load above the base level. Not knowing how JP12 would recover costs of facilities excluded from the Network segment, we have concerns that the parties' proposal could tilt the playing field against BPA service if the customer pays higher transmission rates if it chooses Federal generation over non-Federal generation.

Q. *What is your concern about General Transfer Agreements?*

A. Under the Agreement Regarding Transfer Service (ARTS), BPA committed to acquire and pay for the transmission of Federal power to customers served by transfer for a period of 20 years. As part of this agreement, BPA also committed to initially propose to roll in the costs of these transfer transmission acquisitions to the PF rate. If BPA excludes facilities that we have currently proposed to include in the Network segment, BPA may be required to exclude similar facilities on other transmission providers' systems from the costs that are subject to rolled-in power rate treatment. If BPA were to adopt JP12's segmentation, it could significantly increase the number of transfer customers' PODs subject to the GTA Delivery Charge. This concern is more fully explained in the GTA Delivery Charge rebuttal testimony. Yokota and Miller, BP-14-E-BPA-41, at section 5.

Q. *What conclusions do you draw about the proposal to remove a significant portion of transmission facilities from the Network segment and put them into the Delivery segment?*

A. Doing so would constitute a major change to BPA's longstanding policy of uniform transmission rates, would be counter to national ratemaking policy, would treat similarly situated customers differently without sufficient justification, and would raise concerns with general transfer agreement cost allocation. The proposal would create an economic disadvantage for rural retail utilities based solely on their size and location.

Q. *Should the Administrator prefer JP12's segmentation proposal, how should the costs of the facilities that JP12 would exclude from the Network segment be recovered?*

A. We are unsure. JP06, MSR, and JP12 did not propose any cost recovery mechanism. Powerex generally proposes that the costs be incorporated into the existing Delivery segment or into a new segment so their costs can be recovered from the customers that, according to Powerex, benefit from their use. Opatrny, BP-14-E-PX01-E01, at 20. Powerex's proposal is incomplete as well. A cost allocation mechanism would need to be created before JP12's segmentation proposal could be implemented. There is insufficient time to develop a cost recovery mechanism during this rate proceeding. Thus, should the Administrator prefer JP12's segmentation approach, we would recommend that he not change the segmentation at this time to give all stakeholders the opportunity to participate in formulating a cost recovery mechanism. This approach would be consistent with MSR's recommendation on this matter. Arthur, BP-14-E-MS-01, at 35.

Section 14: Data Updates for the Final Segmentation Study

Q. Do you plan to update the segmentation study for the Final Proposal?

A. Yes. Initiated by the financial updates to the Revenue Requirement Study, Lennox *et al.*, BP-14-E-BPA-31, at 12-13, we plan to update the segmentation study to reflect historical investment through September 30, 2012, the end of fiscal year (FY) 2012. We also plan to update the historical O&M expenses to reflect the latest three-fiscal-year period from October 1, 2009, through September 30, 2012 (FY 2010, 2011, and 2012). In addition, we expect to make some specific revisions to the segmentation of certain lines and substations based on review of the segmentation model since the Initial Proposal.

Q. What specific revisions do you expect to make to the segmentation of lines?

A. The following lines will be moved from the Network segment to Unsegmented facilities, reflecting that this investment is retired or sold and no longer supporting Network segment customers:

CHENOWETH-HARVEY NO 1
CHENOWETH-HARVEY NO 2
JACKSON TAP TO CANAL-SECOND LIFT NO. 1 (SOLD)

In addition, the following lines, identified with new investment in FY 2012, will be included in the Network segment:

ACORD TAP TO GRANDVIEW-RED MOUNTAIN NO 1
BIG EDDY-OSTRANDER NO 1 (ML CLACKAMAS CO)
CARDWELL-COLITZ NO 1 (ML) COWLITZ COUNTY
FOREST GROVE-TILLAMOOK NO 1
MCNARY-JOHN DAY NO 2
OSTRANDER-TROUTDALE NO 1 (ML CLACKACMAS CO)
REDMOND SUBSTATION 230/115KV TIE NO 1
SILVERADO TAP TO PORT ANGELES-SAPPHO NO 1
SLATT-JOHN DAY NO 1 ML GILLIAM CO
SLATT-JOHN DAY NO 1 ML SHERMAN CO
VANTAGE-HANFORD NO 1 ML BENTON CO
VANTAGE-HANFORD NO 1 ML GRANT CO
WALLA WALLA-TUCANNAN RVIER NO 1 ML WALLA WALLA CO
WALLA WALLA-TUCANNON RIVER NO 1 ML COLUMBIA CO

Q. *What specific revisions do you expect to make to substations?*

A. The following substations will be moved to Unsegmented facilities, reflecting that this investment is retired and no longer supports Network or Delivery segment customers.

ALBION SUBSTATION (was Network)
NORWAY SUBSTATION (was Delivery)

In addition, the following substations, identified with new investment in FY 2012, will be included in the Network segment:

ACORD SUBSTATION (BENTON REA)
ARM RELIFT SUBSTATION
BIG HORN SUBSTATION (IBERDOLA)
CENTRAL FERRY SUBSTATION
COASTAL ENERGY GENERATING PLANT
COFFIN BUTTE GENERATING PLANT
COMBINE HILLS II SUBSTATION (EURUS EGY)
CONDON WIND SUBSTATION(SEAWEST)
DECLO METERING POINT
DOOLEY SUBSTATION (WINDY POINT)
FINLEY SUBSTATION (BENTON COUNTY PUD)
FLORENCE SUBSTATION (CENTRAL LINCOLN PUD)
FORT ROCK SUBSTATION (MIDSTATE ELECTRIC COOP)

HARVEST WIND SUBSTATION (KPUD)
HOPKINS RIDGE SUBSTATION
HORN BUTTE SUBSTATION (INVENERGY WIND)
JUNIPER CANYON I SUBSTATION (IR INC.)
KLONDIKE SCHOOLHOUSE SUBSTATION (IBERDOLA)
LINDEN SUBSTATION (KPUD)
LITTLE FALLS GENERATING PLANT
LYN PUMPS PUMPING PLANT
MASHEL PRAIRIE SUBSTATION (OHOP)
OUTBACK SOLAR GENERATING PLANT (OUTBACK SOLAR, LLC)
PATU SUBSTATION
RATTLESNAKE ROAD SUBSTATION (HORIZON WIND)
RIVERBEND LANDFILL GENERATING PLANT (WM LLC)
SHEPHERDS FLAT SUBSTATION (CAITHNESS SF)
SILVERADO SUBSTATION (CLALLAM CO. PUD)
SMITH CREEK POWERHOUSE
WHEAT FIELD SUBSTATION (WFWPP)
WHITE CREEK SUBSTATION (KPUD)

The following substations, identified with new investment in FY 2012, will be included in the Southern Intertie segment:

CELILO CONVERTER NO 3
CELILO CONVERTER NO 4
ROUND MOUNTAIN SUBSTATION

The following substations, identified with new investment in FY 2012, will be included in the Generation Integration segment:

LITTLE GOOSE POWERHOUSE
LOST CREEK POWERHOUSE

Finally, the following facilities were fully removed from the accounting records in FY 2012 and will no longer be included in the Unsegmented facilities:

DECLO (INACTIVE. SEE NOTES)
GOLDBAR (INACTIVE. SEE NOTES)
MICA FLATS (INACTIVE. SEE NOTES)
MINES (INACTIVE. SEE NOTES)
RICHLAND CITY OF (INACTIVE. SEE NOTES)
SATUS AREA (INACTIVE. SEE NOTES)
STEILACOOM TOWN OF (INACTIVE. SEE NOTES)

Q. Does this conclude your testimony?

A. Yes.

DATA REQUEST NUMBER TO REFERENCE:
BPA-JP03-6

RESPONSE BY:
Zabyn Towner - Joint Party 3

ORIGINAL DATA REQUEST:
Do you believe BPA's determination of 34.5 kV and above for the Network segment in 1996 was an appropriate threshold? On what basis? Is that basis still applicable to the current rate case?

EXHIBIT: JP03 (NRU/PNGC) Transmission Direct BP-14-E-JP03-02

PAGE(S): 3
LINE(S): 19-21

DATA RESPONSE: (NOTE: You MUST log in to the site in order to view any documents)
--UPLOADED DOCUMENTS:
https://www.bpa.gov/secure/RateCase/openfile.aspx?fileName=BPA-JP03-6+Response+2.21.13.pdf&contentType=application%2fpdf

--TEXT DESCRIPTION:
Please see attached document.

For technical questions about this request please contact Aleka Scott by phone (5032881234) or email (aleka@pngc.com)

UNITED STATES DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION

IN THE MATTER OF)) FY 2014-2015) PROPOSED POWER AND) TRANSMISSION RATE) ADJUSTMENTS)	BPA Docket No. BP-14 DATA REQUEST RESPONSE OF JOINT PARTY 3 TO BONNEVILLE POWER ADMIN. DATA REQUEST NO. 6

DATA REQUEST RESPONSE
BPA-JP03-6

Request:

Do you believe BPA's determination of 34.5 kV and above for the Network segment in 1996 was an appropriate threshold? On what basis? Is that basis still applicable to the current rate case?

Response:

BPA's determination of 34.5 kV and above as inclusion in the Network segment was appropriate in 1996 and is appropriate today.

The utilities who receive delivery at 34.5 kV continue to transmit power at 34.5 kV across their very geographically large transmission systems. I, Aleka Scott, PNGC Vice President of Transmission and Contracts, have personally examined the one-line diagrams and spoken to the staff of the following utilities to confirm that from the wholesale BPA 34.5 kV delivery points these utilities have a 34.5 kV transmission system that feeds their distribution substation system, not retail customers: Blachly-Lane Electric Cooperative, Clearwater Power Company, Lane Electric Cooperative, Northern Lights, Raft River Rural Electric Cooperative, Flathead Electric Cooperative and West Oregon Electric Cooperative. (We would provide one-line diagrams to BPA in a supplemental response to this data request once confidentiality arrangements are in place. We are filing a motion for a protective order from the Hearing Officer concurrent with this data request response.)

Take, for example, the Lane Electric system. Lane Electric has 2,509 square miles of service territory with 8.6 customers per mile of line. Lane Electric takes delivery at Dorena, Eugene and Alvey at 34.5 kV and then uses its 34.5 kV transmission system to feed six of its distribution substations where power is transformed down to distribution voltage. No distribution voltage retail customers are served off of the 34.5 kV system.

Another example is Raft River Rural Electric Cooperative, whose service area covers 5,950 square miles and has 2.1 customers per mile of line. Raft River also has a 34.5 kV transmission system that starts at its BPA wholesale 34.5 kV point of delivery at Bridge and at Idahome which serves its downstream distribution substations.

Raft River and Lane are typical of utilities who take have wholesale points of delivery on the Integrated Network at 34.5 kV – rural, large service areas, few customers to bear the investment, diversified Federal and non-federal supply since 1996 and using 34.5 kV as a transmission voltage from that point.

Therefore, BPA should retain the current definition of Network segment on the following bases:

1. ***Wholesale*** deliveries at 34.5 kV are made at transmission voltage and 34.5 kV remains a transmission voltage for most of those utilities who receive this service. From the 34.5 kV BPA point of delivery, the 34.5 kV transmission lines transmit power to distribution substations anywhere from 10 to 50+ miles away from the BPA point of delivery. So 34.5 kV is both **wholesale and transmission**.

   Non-federal power is received at wholesale Network substations at 34.5 kV and has been since 1996. Therefore, the **equitable allocation between federal and non-federal argument is no longer valid**, nor has it been since 1996. Starting in 1996, preference customers began diversifying their federal power supply and serving their load with non-federal power from a variety of non-federal suppliers. Case in point, for the 1996-2001 period, PNGC members supplied 30% of their load with non-federal power from an array of non-federal parties, including PGE, Pacificorp, and Powerex. In the 2001-2011 period, many preference utilities supplied part of their load with non-federal power from various suppliers, including Powerex, Tacoma, Seattle, PGE, PSE, Avista, and Pacificorp to name a few. In this period under the Regional Dialogue contracts, preference customers are expressly permitted and encouraged to bring non-federal power to serve load. Many NRU and PNGC members are bringing non-federal power to load over the Integrated Network including those wholesale points of delivery at 34.5 kV and above.

2. It is my understanding, as an expert witness for transmission issues, that BPA is charged, by statute, to **set rates that encourage the "widest possible diversified use of electric power at the lowest possible rates** to consumers with sound business principles." 16 U.S.C. §838g. If BPA were to follow the suggestions made by other parties in this case to change the 34.5 kV and above threshold, the result could be contrary to this directive.

a) The effect of moving a set of costs from being spread across approximately 34,471 MW of sales (BPA-14-E-BPA-07A, page 13, line 24) to some small fraction of those sales would be unacceptable. Since other parties proposing changes to the definition of delivery have not suggested how many MWs would be impacted, nor the costs associated with their proposal, nor even listed the impacted utilities in their testimony, it is difficult to know the impact of changing the definition of the Integrated Network, but nevertheless we know the effect would be large. Even if half of the NT billing determinants were impacted (say 3,500 MW), every dollar of revenue requirement removed from Network would increase the charge to the new “delivery” segment by a factor of 10. So the impact of $1,000,000 distributed over 34,471 MW is $29/MW-year. But this same $1,000,000 distributed over 3,500 MW would be $286/MW-year. Because we don’t know the amount of dollars that would move under any new definition of Integrated Network, nor the dollars associated with such a change, nor the impacted utilities or MWs, we cannot calculate a rate impact except to say that it will impact the new delivery customers at least **by a factor of 10**, probably considerably more.

b) The customers who would be harmed if the current definition of the Network segment were changed are among the least densely populated in the Northwest. Take, for example, the PNGC members listed in the table below. These utilities have some of the lowest system densities (as measured by customer per line mile) and the largest service territories (as measured in square miles). To shift costs onto these utilities that have the largest service territories and the fewest customers simply does not meet the test of good sense, nor statutory directives as to widest use at lowest rates, nor the equitable allocation standard

PNGC Member	Customers Per Mile of line*	Square miles of service area
Blachly-Lane Electric Cooperative	7.07	380
Central Electric Cooperative	8.21	5,300
Clearwater Power Company	3.63	4,698
Consumers Power, Inc.	7.05	2,525
Coos-Curry Electric Cooperative	10.69	2,343
Douglas Electric Cooperative	5.86	2,500
Fall River Rural Electric Cooperative [1]	6.45	2,848
Lane Electric Cooperative	8.62	2,509
Lincoln Electric Cooperative Inc	5.76	1,125
Northern Lights, Inc. [2]	6.41	5,727
Okanogan County Electric Cooperative	7.00	1,215
Raft River Electric Cooperative	2.10	5,950
West Oregon Electric Cooperative	6.30	1,224

*from RUS Form 7 or similar data for CY2011

Customers of IOUs have a state commission that insures that costs are spread on a state-wide basis thus making electricity affordable for all in the state. This means that residential consumer in an urban area with high system densities and the residential consumer in a rural, more sparsely populated and more expensive to serve area are charged equal rates. It is BPA who has performed this task for spreading transmission costs over a large pool of customers to make it affordable for all. This is indeed the embodiment of "widest possible diversified use of electric power at the lowest possible rates to consumers with sound business principles." 16 U.S.C. §838g

3. The definition of the Integrated Network segment as it currently stands is a **bright line** test. The current definition of Network facilitates only wholesale deliveries. Power is moved away from the wholesale34.5 kV points of delivery on 34.5 kV transmission lines with no retail service drops, and includes deliveries of both Federal and nonfederal

power, at a postage stamp rate. Given these factors, we find that the current definition of the Network segment at 34.5 kV and higher it is an appropriate bright line test.

4. As BPA has pointed out, changing the definition of the Network to a different bright line would be enormously controversial requiring, review of over 3,000 facilities, engage enormous energy from utilities using staff and hiring consulting engineers to make their cases, and would ultimately be just as imperfect as the existing bright line test, and can only result in shifting costs from the largest customers to the smallest.

Supplemental response to BPA-JP03-6
March 1, 2013

I, Aleka Scott, attest that I have seen the following one-line diagrams and spoken to staff at the utilities in question. These 34.5 KV transmission lines described below go from the BPA POD to the utility's substations where power is transformed from transmission voltage (34.5 kV) to distribution voltage. There are no retail services off of the 34.5 kV transmission lines described below.

Flathead Electric Cooperative (FEC), BPA Meter Diagram dated 1/13/2013 by Victor Hitchens

FEC has two wholesale BPA PODs with delivery voltage at 34.5 kV, Columbia Falls and Kalispell. FEC has approximately **120 miles of 34.5 kV transmission lines** that connect its wholesale PODs to 18 FEC substations where power is stepped down from transmission voltage (34.5 kV) to distribution voltage. FEC serves approximately 1,156 square miles of service area.

Lane Electric Cooperative, BPA Meter Diagram dated 11/2/2011 by BPA CSE John Schaad, and a Lane Electric Cooperative Transmission System One-Line Drawing, dating 6/18/2010

Lane has three BPA PODs at 34.5 kV POD: Dorena, Eugene, and Alvey.
Fifty seven (57) miles of 34.5 kV transmission lines connect these three wholesale PODs to 5 Lane Electric substations where voltage is stepped down from 34.5 to 12.5 kV for distribution to LEC's retail loads. LEC has 2,509 square miles of service territory with 8.62 customers per mile of line.

Clearwater Power Company (CPC), BPA Meter Diagram dated 8/23/2011 by BPA CSE Walker Miller and CPC diagrams, Genesee to Anatone 34.5kV Transmission Line One Line dated 10/07/2009

CPC has **34.87 miles of 34.5 kV transmission lines** that connects its BPA wholesale POD at Heimark to 4 of its substations where power is stepped down from transmission voltage (34.5 kV) to distribution voltage. CPC also has 69 kV and 115 kV transmission voltages in its service area. CPC serves 4,698 square miles of service area with 3.63 customers per mile of line.

Northern Lights Inc. (NLI), BPA Meter Diagram dated 3/10/2011 by BPA CSE Victor Hitchens.

NLI has a BPA wholesale 34.5 kV POD at Priest River and approximately **25 miles of 34.5 kV transmission lines** that serves 3 NLI substations where power is transformed from transmission voltage (34.5) kV to distribution voltage (13.2 kV). NLI serves 5,727 square miles of service area with 6.41 customers per mile of line.

Blachly Lane Electric Cooperative (BL), BPA Meter Diagram dated 4/7/11 by John Schaad and Blachly-Lane System Map dated May 2003.

BL has **28.29 miles of 34.5 kV transmission lines** that connects its BPA wholesale Mapleton POD and Junction City POD with 3 of its BL substations where power is stepped down from transmission voltage (34.5 kV) to distribution voltage (12.5 kV) .

West Oregon Electric Cooperative (WOEC), WOEC One Line Drawing date 12/31/12

WOEC has a BPA wholesale 34.5 kV POD at Timber and at Warren. These two wholesale PODs are connected by **29.44 miles of 34.5 kV transmission lines** that serve 5 WOEC substations the transform power from transmission voltage (34.5) kV to distribution voltage. WOEC serves 1,224 square miles of service area with 6.30 customers per mile of line.

Raft River Rural Electric Cooperative (RRREC), BPA Meter Diagram dated 3/31/2008 by Dusty Glans and RRREC One Line Diagram dated 11/15/2000

RRREC has BPA wholesale PODs at 34.5 kV at Bridge and Idahome. It has **43 miles of 34.5 kV transmission lines** that connects 5 substations the transform power from transmission voltage (34.5) kV to distribution voltage. RRREC serves 5,950 square miles of service area with 2.10 customers per mile of line.

DATA REQUEST NUMBER TO REFERENCE:
BPA-JP06-1

RESPONSE BY:
Jason Kuzma - Joint Party 6

ORIGINAL DATA REQUEST:
A review of your testimony leaves us with an understanding that you believe that a number of facilities currently segmented to the network should not be included in the network. However, your testimony is opaque about how BPA would recover the costs of the facilities that you would remove from the network segment. How do you propose that BPA collect the costs associated with the facilities that you would remove from the network?

EXHIBIT: Direct Testimony of Avista Corporation, Portland General Electric Company, and Puget Sound Energy, Inc. BP-14-E-JP06-01

PAGE(S): All
LINE(S): All

DATA RESPONSE: (NOTE: You MUST log in to the site in order to view any documents)
--UPLOADED DOCUMENTS:

https://www.bpa.gov/secure/RateCase/openfile.aspx?fileName=Response+to+Data+Request+BPA-JP06-01.pdf&contentType=application%2fpdf

BONNEVILLE POWER ADMINISTRATION
2014 POWER AND TRANSMISSION RATE PROCEEDING

DOCKET NO. BP-14

DATA REQUEST BPA-JP06-01

Data Request BPA-JP06-01:

DIRECTED TO: Joint Party 6

REQUESTOR'S NAME: Thomas Davis - Bonneville Power Administration

EXHIBIT: Direct Testimony of Avista Corporation, Portland General Electric Company, and Puget Sound Energy, Inc. BP-14-E-JP06-01

PAGE(S): All

LINE(S): All

DATA REQUEST:

A review of your testimony leaves us with an understanding that you believe that a number of facilities currently segmented to the network should not be included in the network. However, your testimony is opaque about how BPA would recover the costs of the facilities that you would remove from the network segment. How do you propose that BPA collect the costs associated with the facilities that you would remove from the network?

For technical questions about this request please contact Thomas Davis.
Phone: (503.230.3968)
Email: (tedavis@bpa.gov)

Response:

Avista Corporation ("Avista"), Portland General Electric Company ("Portland General") and Puget Sound Energy, Inc. ("PSE") object to Data Request BPA-JP06-01 as unduly burdensome and beyond the scope of the Direct Testimony of Avista Corporation, Portland General Electric Company, and Puget Sound Energy, Inc., Exh. No. BP-14-E-JP06-01. Without waiving this objection and subject thereto, Avista, Portland General and PSE provide the following response.

The Direct Testimony of Avista Corporation, Portland General Electric Company and Puget Sound Energy, Inc., Exh. No. BP-14-E-JP06-01, does not address collection of costs by the Bonneville Power Administration ("BPA") associated with facilities removed from the network.

The Direct Testimony of Avista Corporation, Portland General Electric Company and Puget Sound Energy, Inc., Exh. No. BP-14-E-JP06-01, points out the following:

- BPA, by relying on an arbitrary 34.5 kV and above bright line voltage test, has not demonstrated that the segmentation it proposes reflects equitable allocation of transmission costs and consistency with cost allocation principles.

- BPA's 1996 transmission rates were adopted on a nonprecedential basis pursuant to a settlement that included a nonprecedential segmentation;

- Under the nonprecedential 1996 settlement, facilities of 34.5 kV and above were included in the Network, even though they were installed and used to serve only a subset of BPA's transmission customers;

- In this proceeding, BPA does not present a segmentation analysis but rather relies on the nonprecedential segmentation from the 1996 BPA rate case and a desire to avoid "controversial judgment calls" and a "time-consuming" study;

- BPA's reliance in this proceeding on the nonprecedential 1996 segmentation is inconsistent with the segmentation methodology prescribed by BPA for exchanging utilities in BPA's current, 2008 Average System Cost Methodology and may result in an improper classification of BPA's facilities and an improper allocation of BPA's costs; and

- BPA should perform and present a segmentation study in order to support its rates in this proceeding.

Holland, *et al*., Exh. No. BP-14-E-JP06-01, at page 2, lines 3-21.

Thus, the Direct Testimony of Avista Corporation, Portland General Electric Company and Puget Sound Energy, Inc., Exh. No. BP-14-E-JP06-01, addresses BPA's failure to support its proposed segmentation of transmission costs and does not address the methodology by which BPA could collect such costs once properly segmented. The absence of a proposal as to how BPA should collect costs associated with facilities removed from the network in the Direct Testimony of Avista Corporation, Portland General Electric Company and Puget Sound Energy, Inc., Exh. No. BP-14-E-JP06-01, should not release BPA from its obligation to support its segmentation in its proposal.

DATA REQUEST NUMBER TO REFERENCE:
BPA-JP12-5

RESPONSE BY:
Giuseppe Fina - Joint Party 12

ORIGINAL DATA REQUEST:
For “Grandview” line 1, “Red Mountain” line 1, “Red Mountain” line 2, “Richland” line 3, please explain how you arrive at only 33% of the Red Mountain substation being assigned to non-Network when 100% of the three transmission lines interconnecting the Red Mountain substation are being assigned to non-Network. Please identify which portions of the Red Mountain substation you assign to Network.

EXHIBIT: Direct Testimony BP-14-E-JP12-01

PAGE(S): Exhibit 3
LINE(S): See below

DATA RESPONSE: (NOTE: You MUST log in to the site in order to view any documents)

--TEXT DESCRIPTION:
Red Mountain substation was allocated to 67% network, 33% non-network. After further powerflow analysis using contingencies, the Red Mountain substation should be changed to 100% non-Network facility.

For technical questions about this request please contact Joe Fina by phone (4257838649) or email (gfina@snopud.com)