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TESTIMONY OF

MARK H. EBBERTS

Witness for Bonneville Power Administration

SUBJECT: 7(c)(2) Industrial Margin Study; Floor Rate Test; Flexible Rate Option

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Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Mark Ebberts. My qualifications are contained in WP-02-Q-BPA-18.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to sponsor the 7(c)(2) Industrial Margin Study and to explain the derivation of the typical industrial margin used to set the Industrial Firm Power (IP-02) rate for the direct service industrial customers (DSIs). It also explains one proposed change to the way the DSI floor rate is derived, and describes the Flexible rate option for DSI customers.

Q. How is your testimony organized?

A. This testimony is in six sections. Section 1 is this introduction. Section 2 explains why we are calculating the margin and describes the data base used in the calculation. Section 3 describes the methodology used to calculate the margin. Section 4 describes the margin itself. Section 5 describes the proposed change to the floor rate test. Section 6 describes the DSI Flexible rate option.

Section 2. Rationale for the Margin and Data Base

Q. What is the section 7(c)(2) industrial margin?

A. Section 7(c)(1)(B) of the Pacific Northwest Electric Power Planning Act (Northwest Power Act) provides that rates to the DSIs shall be set "at a level which the [Bonneville Power] Administrator determines to be equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region." Section 7(c)(2) of the Northwest Power Act further provides that:

"The determination under paragraph (1)(B) of this subsection shall be based upon the Administrator's applicable wholesale rates to such public body and cooperative customers and the typical margins included by such public body and cooperative customers in their retail industrial rates but shall take into account:

(A) the comparative size and character of the loads served;

(B) the relative costs of electric capacity, energy transmission, and related delivery facilities provided and other service provisions; and

(C) direct and indirect overhead costs, all as related to the delivery of power to industrial customers . . . ."

Thus, rates to the DSIs are set by adding a typical retail margin, taking into account the factors stated above, to the applicable wholesale rate. The purpose of the 7(c)(2) Industrial Margin Study is to calculate the typical retail margin.

Q. How was the margin study data collected?

A. BPA requested that the Public Power Council (PPC) assist in collecting the necessary data. Only public utilities serving one or more industrial customer(s) with a peak load of 3.5 MW or above were eligible to participate in the study. This is the same requirement used in all past margin studies. BPA, working with the PPC and a DSI representative (Regulatory & Cogeneration Services, Inc., or RCS), identified the data that would be requested in order to calculate the typical margin. The PPC sent each utility a letter requesting this data. The request also explained that the information would only be used for the purpose of calculating the margin and would otherwise remain confidential.

Q. Why was it necessary to preserve the confidentiality of the collected data?

A. BPA was informed that the utilities believe public distribution of customer-specific information could cause them competitive harm. If there were no assurance of confidentiality, it is doubtful that many utilities would have cooperated in providing the information. This result would have created a less accurate sampling of the data used to determine the industrial margin.

Q. *What steps were taken to maintain confidentiality?*

A. Utilities agreed to submit data to the PPC with assurance that it would be used by BPA for the sole purpose of calculating the typical industrial margin. As a condition for providing this data, the utilities required that all references identifying the utility and its industrial customer(s) be deleted from all data sources. Therefore, all utility names and industry names have been masked from the data base and kept confidential. Each utility has been assigned a random number as an identifier. This was not the first time utility and industry identities have been masked in a margin study. The masking of the utilities' identities was also done as part of the 1985 margin study. Also, entities wishing to review the data, including BPA, were required to sign a confidentiality agreement that limits its use and dissemination.

Q. *Which utilities were eligible to provide data for use in the margin study?*

A. As noted, the margin study includes only utilities with at least one industrial customer with a peak demand of at least 3.5 megawatts. BPA identified 35 public body and cooperative customers believed to be serving at least one industrial customer with a peak demand of at least 3.5 megawatts

Q. *What definition of "industrial customer" was used in compiling this data base?*

A. Consistent with past margin studies, "industrial customer" was defined as a customer that receives firm service and is engaged primarily in manufacturing, processing, refining, and/or mining.

Q. How many utilities were included in the margin study?

A. There were 22 responses from eligible public body and cooperative customers of BPA. These responses provided the cost information necessary to calculate the industrial margin.

Q. What specific types of data did each utility provide?

A BPA requested that utilities provide their most recent cost of service analyses (COSA) used in establishing their existing industrial customer rates. BPA also requested information from any power contracts that a utility may have with an industrial customer for providing electrical service under other than traditional industrial tariffs (such as market-based or market-access pricing). The data base consists of complete COSAs or various forms of summary data received from the utilities, margin information provided by the utilities, plus information from rate schedules, and contracts currently in effect.

Q. What information was contained in the COSAs?

A. COSAs generally contain expenses that are individually identified and categorized based upon the functionalization and allocation used by the utilities. The functionalization is the separation of costs into categories of cost causation, including production, transmission, distribution, taxes, and overhead. The allocation of costs is the separation of the functionalized costs to customer classes such as residential, commercial, and industrial.

Section 3. Methodology

Q. How did you derive individual utility margins?

A. Basically BPA followed the same methodology as used in the 1996 margin study. Where COSAs were provided, we derived individual utility industrial margins by analyzing the categorical costs the utilities allocated to their industrial consumers. BPA relied on utility data used to prepare the COSA, and the same information was used in determining how costs were functionalized among the various cost categories and allocated to their industrial customers. In other words, BPA generally accepts each utility's functionalization and allocation methods.   The only exception was in the case of a utility functionalizing programmatic conservation costs to the "Other" cost category. These costs were placed in the "Production" cost category for purposes of calculating this utility's industrial margin, consistent with the treatment of this cost in past margin studies.

In sum, BPA's task was basically to determine what utility costs should appropriately be considered as part of the typical margin and which should not. The costs categories excluded from the margin calculation were those related to the production, transmission, or distribution functions.

Q. *How did you assign the costs to the cost categories?*

A. For utilities that provided complete COSAs, the costs included in the studies are typically purchased power, production, operations and maintenance (O&M), transmission O&M, distribution O&M, depreciation, debt service, capital expenses, administrative and general expenses, in-lieu taxes, conservation costs, and other overhead costs. We assigned the costs listed above to five cost categories based on the utilities' allocation of costs to their industrial customers in the following categories: Production, Transmission, Distribution, Revenue Taxes, and Other Overhead Costs. Generally this is fairly straightforward. For example, we assigned all purchased power costs to the production cost category. Transmission O&M would be assigned to the Transmission category. However, some costs are not directly associated with a Production, Transmission, Distribution, or Other overhead category. For example, administrative and general (A&G) costs, depreciation expenses, or capital expenses as a category of costs needed to be apportioned to four of the five (excluding Revenue Taxes) categories of costs. We apportioned these costs to the Production, Transmission, Distribution, and Other category based on the relative proportion of O&M costs already functionalized by the utility to these cost categories. Thus, if total O&M allocated to the industrial class is $100, of which $40 is functionalized to transmission, we assigned 40 percent of A&G to the Transmission cost category. Return on working capital was apportioned based on the proportion of working capital assigned to those same cost categories, and revenue or income credits were apportioned based on relative shares of revenue requirement. Three types of cost categories were always assigned directly to the Other category. These were meter reading, billing and collections, and customer service. All revenue taxes, when identified, were assigned to the Revenue Tax category.

Next, the various categories of costs were totaled and then divided by the total kilowatthour (kWh) sales during the utility's test period to arrive at a mills per kWh (mills/kWh) figure for each category. All of the costs included in the Production, Transmission, Distribution, Revenue Taxes, and Other cost categories were totaled and divided by total sales. The result is the amount per kWh of each of the five categories that contributes to the overall rate.

Q. How did you allocate costs for the utilities that did not provide complete COSAs?

A. In a few cases BPA did not receive complete COSAs from utilities. Instead the data consisted of utility statements or summaries regarding contract margins or other overhead costs. In these instances, where the utility specifically identified the amount of margin or other overhead costs associated with a particular contract, BPA accepted it.

Appendix A of the Wholesale Power Rate Development Study, WP-02-BPA-E-05, contains summary spreadsheets displaying costs apportioned to each of these five categories for each utility participating in the margin study.

Section 4. The Margin

Q. What cost categories are included in the margin calculation?

A. BPA is using the same cost categories used in the 1996 rate case. When BPA calculated the margin originally, it made a size of load adjustment, substituting BPA's DSI delivery facility costs for the distribution costs calculated from the utility sample. This substitution was made in order to account for the lesser costs of serving large industrial customers like the DSIs. Failure to make the substitution would have caused the distribution cost component of the margin to be overstated.

To set the IP-02 base rate, BPA has again substituted its delivery facility costs for the distribution costs contained in the margin study. In applying this methodology, we are skipping the step of including distribution costs in the margin only to substitute another cost later. Therefore, this change does not affect the DSI rate. It is simply a more straightforward application of the methodology, and makes the size of load adjustment unnecessary. Therefore, as stated above, costs included in the typical industrial margin are those direct and indirect overhead costs that are not associated with the production, transmission, or distribution of electricity. Costs included in the margin calculation are those costs typically associated with such activities as meter reading, billing and collections, and customer service. Also not included in the margin category of costs were revenue taxes.

Q. Why is it appropriate to exclude costs functionalized to power and transmission from the margin?

A. This is the same methodology that BPA employed in 1985 and 1996, and we are excluding these costs for the same reason. The seasonally and diurnally adjusted rates in the proposed IP-02 schedule are based on a combination of the industrial margin and the proposed Priority Firm Power (PF-02) rates. The proposed PF-02 rate is designed to recover the costs of providing generation. Transmission costs will be determined in the transmission rate case and will be charged to customers by the BPA Transmission Business Line. Since generation and transmission costs will be recovered through BPA's power and transmission rates applicable to the DSIs, it would be inappropriate to include them in the industrial margin as well.

Q. Why is it appropriate to exclude revenue taxes from the margin?

A. We continued the method used in the 1996 rate case. The Northwest Power Act directs the Bonneville Administrator to base the DSI margin on the "typical" retail margins included in rates by BPA's public body and cooperative customers. It is our understanding that only utilities in Washington State are subject to a state revenue tax. While 20 out of the 22 utilities providing margin data collect from their industrial customers some portion of the utilities revenue tax burden, we can only conclude that utilities reporting revenue taxes are located in Washington State. Therefore, for the purpose of making any determination regarding revenue taxes, the sample is unrepresentative of BPA's wider customer base, which includes customers that sell power to industrial loads in Oregon, Idaho, Nevada, and Montana. None of the state governments of these states collect a revenue tax through their public or cooperative utilities. Because such taxes are not typical, it is reasonable to conclude that they should not be included in the calculation of a "typical" margin.

Q. How many BPA utility customers in Washington State have industrial load, as opposed to other states?

A. Thirty-four utilities with industrial customers are located in Washington. Forty-seven utilities with industrial customers are located outside of Washington, and therefore do not pay a state revenue tax.

Q. How did you calculate the "typical" margin?

A. First, we calculated the individual utility margins. We then weighted the individual margins to arrive at the overall margin.

Q. What weighting technique did you employ?

A. We multiplied each margin by the total annual energy consumed by each utility's large industrial customers. Thus, we weighted each margin by the amount of energy sold by the utility to its industrial customers, thereby giving greater weight to the utilities with more sales. We then added all the individually weighted margins and divided by the sum total energy for all utilities. We derived an overall typical margin of 0.46 mills/kWh.

Q. Have you escalated the margin to the middle of the rate period?

A. No.

Q. Why have you chosen not to include an escalator?

A. We continued the method used in the 1996 rate case. BPA continues to find that under current market conditions, utilities have severe limits on their ability to raise rates to their large industrial customers. For example, the Washington State Electricity System Study (Legislative Electricity Study 6560, January 1999) found that while residential and commercial rates have remained virtually unchanged over the period of study between 1995 and 1997, industrial rates actually declined by an average of 5.5 percent for the state as a whole. This analysis did not include Washington's DSIs. Thus, BPA has found no evidence of rate escalations. The fact that the margin based on our sample has essentially remained the same indicates that the market for large industrial customers is competitive, and BPA finds no contrary indication of escalating rates for this particular customer class. Furthermore, BPA's average power rate being proposed for PF customers in 2002, which in turn is passed through to their industrial customers, will have remained unchanged for the ten-year period 1996-2006.

Q. Did you include a character of service adjustment for the DSI top quartile?

A. No. BPA does not plan to offer less than firm service to the DSIs in the 2002 rate case.

Section 5. Floor Rate Test

Q. What is the floor rate test?

A. Section 7(c)(2) of the Northwest Power Act provides that the rate developed pursuant to that section "shall in no event be less than the rates in effect for the contract year ending on June 30, 1985." This is the so-called "floor rate test." Simply stated, the floor rate test requires that BPA recover revenues from its DSI customers in the test period equal to or greater than the revenues it would recover in the test period using the applicable IP rate in effect on June 30, 1985.

Q. How is the floor rate test calculated?

A. The first step in calculating the floor rate is to apply the IP-83 Standard rate charges to test period (FY 2002-2006) DSI billing determinants. The resulting revenue figure is then divided by total IP test period loads to arrive at an average rate in mills per kWh. This rate is reduced by an Exchange Cost Adjustment and a deferral that were included in the IP-83 rate. Both adjustments are made on a mills per kilowatt-hour basis. *See* Wholesale Power Rate Development Study Documentation, WP-02-E-BPA-05A, Section 2.3, Table RDS23. The floor rate is then applied to the test period DSI billing determinants to determine floor rate revenues. Revenues at the proposed IP rate charges are compared to revenues at the floor rate. If expected IP-02 rate revenues match or exceed floor rate revenues, then the IP rate is the applicable rate. If not, then rates must be adjusted accordingly.

Q. Are you proposing any changes to the way the floor rate is calculated?

A. Yes. We are proposing to remove the transmission costs from the IP-83 Standard rate.

Q. Please explain why.

A. The IP rate and the IP-83 Standard rate have always been delivered product rates. This means that both power and transmission costs were included in the test period IP rate and the IP-83 Standard rate. Beginning this rate case, there will be separate rate cases for power and transmission. Therefore, the floor rate test will be done for power only. To do this power only comparison, the transmission costs included in the IP-83 Standard rate were removed.

Q. Were other alternatives considered?

A. Yes. We also considered estimating the transmission rates that the DSIs may pay in the next rate period and adding those costs to the proposed IP-02 rate.

Q. Why was that option rejected?

A. Adjusting the IP-83 Standard rate by removing the transmission costs from the rate is the most straightforward and accurate approach. The transmission costs included in the IP-83 Standard rate are known and removing them from the rate involved no guesswork. However, transmission costs and rates that will be applicable to DSI customers in the next rate period are not known at this time, and an attempt to project those future costs would not be as accurate as removing known identifiable costs.

Q. What is the impact of your proposal?

A. By removing the transmission costs from the IP-83 rate, the floor rate is 20.98 mills per kWh. With transmission costs left in, the floor rate would be 24.78 mills per kWh, a difference of 3.80 mills per kWh.

Q. Isn't this effectively a reduction of the floor rate?

A. No. Removing transmission costs from the calculation does not lower the floor rate in the sense that it permits the DSI customers to acquire power at a lower cost from BPA. Rather, it merely allows BPA to compare an unbundled test period power rate to an unbundled power floor rate, and no changes have been made, or are being proposed at this time, to any power costs in the IP-83 Standard rate. Therefore the floor rate, after adjusting for the transmission component and substituting test period billing determinants, is unchanged. The transmission costs that were previously included in the floor rate calculation will be paid separately by any DSI customer that purchases power from BPA.

Section 6. Flexible Rate Option

Q. Why is BPA proposing to offer optional flexible demand and energy charges for its DSI customers?

A. BPA is proposing to continue the Flexible rate option to its PF and New Resource rate customers and believes the same option should also be made available to its DSI customers. While the Flexible rate option ensures that BPA receives the same revenues on a net present value basis that BPA would have received under the posted rates, the Flexible rates allow BPA to structure payments to better meet customers' needs.

Q. Who is eligible for the Flexible rate option ?

A. BPA intends to offer this rate option only to DSI customers that make a purchase commitment to BPA under one of its IPTAC rates. The IPTAC rates are described in the testimony of Berwager *et al.*, WP-02-E-BPA-09.

Q. Please describe the structure of the Flexible rate option.

A. The Flexible rate option will allow a DSI customer to structure its seasonal and diurnal rates differently than allowed posted under the IPTAC rate schedules. Before offering the rates to a customer, however, BPA will ensure that a revenue test has been satisfied. The revenue test requires that the revenues for each specific agreement must be the same, or greater, on a Net Present Value (NPV) basis than BPA would have received under a straight application of the IPTAC rate schedule (NPV Revenue Test). This continues a fundamental principle of the revenue test contained in previous BPA flexible rate offers.

Q. Can DSI customers use the Flexible rate option for cost-based indexed sales?

A. No. Customers can receive a cost-based index rate with the IPTAC, but not through the Flexible rate option. Specific parameters have been established elsewhere for the cost-based indexed IP rate. *See* Buskuhl *et al.*, WP-02-E-BPA-21.

Q. Does this conclude your testimony?

A. Yes.