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TESTIMONY of

DANIEL H. FISHER, GERARD C. BOLDEN,

GREG C. GUSTAFSON, and RAYMOND D. BLIVEN

Witnesses for Bonneville Power Administration

SUBJECT: RATE DESIGN

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Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Daniel H. Fisher, and my qualifications are contained in WP-10-Q-BPA-18.

A. My name is Gerard C. Bolden, and my qualifications are contained in WP-10-Q-BPA-08.

A. My name is Greg C. Gustafson, and my qualifications are contained in WP-10-Q-BPA-24.

A. My name is Raymond D. Bliven, and my qualifications are contained in WP-10-Q-BPA-06.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to sponsor the 2010 Wholesale Power Rate Schedules and 2010 General Rate Schedule Provisions (GRSPs), WP-10-E-BPA-07, and the rate design portion of the Wholesale Power Rate Development Study (WPRDS), WP-10-E-BPA-05, section 2. This testimony describes changes from the current PF-07R rates that are in effect for FY 2009.

Q. How is your testimony organized?

A. Section 1 is this introduction. Section 2 provides an overview of the rate design changes being proposed in this case. Section 3 discusses the Priority Firm Power (PF) rate. Section 4 discusses the PF Exchange rate. Section 5 discusses the Industrial Firm Power (IP) and New Resource Firm Power (NR) rates. Section 6 discusses the Firm Power

Products and Services (FPS) rate. Section 7 discusses calculation of the value of reserves for the IP Rate. Finally, section 8 discusses the Low Density Discount.

Q. *Are there any other clarifying points to be made in this testimony?*

A. Yes. One clarification that will be included in the final GRSPs is the reference to the Mid-C Dow Jones Index. The language in the GRSPs should have specified that we intend to use the Mid-C Dow Jones Firm Index only. GRSPs, WP-10-E-BPA-07, section III.14. Another clarification that will be included in the final GRSPs is that the Emergency NFB Surcharge will be included in the rate adjustments applicable to the 7(b)(3) Supplemental Rate Charge Adjustment.

Section 2: Overview of Rate Design Changes

Q. *What is the general approach to rate design that is being proposed in this Initial Proposal?*

A. Our general approach for the design of rates in the Initial Proposal is to continue to implement the rate design as adopted in the WP-07 Supplemental Final Proposal for the PF rate and to update the shape of energy rates for the IP and NR rates.

Q. *Please describe any proposed changes to the rate design.*

A. The Initial Proposal continues the current rate design for PF rates and changes the level of the PF rate components proportionate to the change in the total revenue requirement allocated to the PF Preference rate class. The proposed PF rate design continues to consist of monthly Heavy Load Hour (HLH) Energy rates, monthly Light Load Hour (LLH) Energy rates, monthly Demand rates, and an annual Load Variance rate.

The PF Exchange rate is proposed to be developed in the same manner as in the WP-07 Supplemental Final Proposal. The proposed PF Exchange rates would consist of two components: a Base PF Exchange Rate and utility-specific 7(b)(3) Supplemental Rate Charges. The Base PF Exchange rate will be an annual rate for the entire rate period. The sum of the Base PF Exchange rate and the utility-specific 7(b)(3) Supplemental Rate Charge is the utility-specific total PF Exchange Rate.

We propose a minor modification to the monthly HLH and LLH Energy rates for the IP and NR rates. The IP and NR rate Energy components will be reshaped to the current forecast of monthly HLH and LLH market prices from the Market Price Forecast Study, WP-10-E-BPA-03. The monthly IP and NR Demand rates will still be equal to the monthly PF Demand rates. The IP and NR Load Variance rates will still be equal to the PF Load Variance rate.

Another change to the IP rate would involve a calculation for the Value Of Reserves (VOR) that are expected to be provided by the customers purchasing at the IP rate, and the resulting VOR rate credit, as discussed in section 7.

The PF Exchange rate, NR rate, IP rate, and FPS rate will continue to have a 7(b)(3) Supplemental Rate Charge applied.

Section 3: Priority Firm Power (PF) Preference Rate

Q. What is the PF Preference rate?

A. The PF Preference rate applies to BPA's power sales to public bodies, cooperatives, and Federal agencies. Power sold at the PF Preference rate is used to meet these customers' respective general requirements as defined by section 5(b) of the Northwest Power Act. Section 7(b)(4) further defines the general requirements of these customers to be exclusive of any new large single load.

Q. How are the Demand, Energy, and Load Variance rates calculated for the PF-10 rate?

A. We propose to use the same method that was used in the WP-07 Final Proposal and WP-07 Supplemental Final Proposal for the PF-10 rate. An updated allocated revenue requirement will be used to proportionately scale (*i.e.*, by an equal percentage applied to each rate component) upward the WP-07 Supplemental Final Proposal rate components.

The relationship of the monthly HLH and LLH Energy rates, Demand rate, and Load Variance rate for the PF-07R rate components will be the template for the PF-10 rate components. WPRDS, WP-10-E-BPA-05, section 2, Table 2.7. The revenue that would be recovered using the PF-07R rate components is compared to the allocated revenue requirement for the PF Preference rate. The resulting ratio is used to scale the PF-07R rate components to compute the PF-10 rate components. The scaled rates then will recover the portion of the total revenue requirement allocated to the PF Preference class of service in total when applied to the forecast PF Preference billing determinants.

Q. Are there any known changes to the PF-10 rate that are not currently reflected in the Initial Proposal?

A. Yes. As noted in the testimony of Brodie, *et al*., WP-10-E-BPA-16, section 5.2, RAM2010 did not use the PF-07R component rates in the scaling process. This will be changed for the Final Proposal. The effect of this pending update will be that the PF-10 rates will be slightly different due to rounding differences.

Q. Are there any other changes to the PF-10 rate?

A. Other than the rate level, we are proposing no changes to the rate applicability, billing determinants, or the billing factors. However, changes are being proposed to the GRSPs that affect the PF-10 rates. For example, BPA is proposing several changes to the Cost Recovery Adjustment Clause, the Dividend Distribution Clause, and the NFB Mechanisms. *See* Rodehorst, *et al*., WP-10-E-BPA-14. There are also several changes to the Conservation Rate Credit and Green Energy Premium. *See* Ingram, *et al*., WP-10-E-BPA-17. Finally, there are some language clarifications for the Targeted Adjustment Clause.

Section 4: Priority Firm Power (PF) Exchange Rate

Q. What is the PF Exchange rate?

A. The PF Exchange rate applies to BPA's power sales to utilities participating in the Residential Exchange Program (REP). The difference between BPA's PF Exchange rate and the exchanging utility's average system cost (ASC) of resources, multiplied by the utility's qualifying residential and small farm load, equals the monetary benefits provided to the utility under the REP. The PF Exchange rate also applies to actual power sales under an "in lieu" transaction, as provided by section 5(c)(5) of the Northwest Power Act. Generally speaking, an "in lieu" transaction allows BPA to acquire power that is less expensive than the utility's ASC in lieu of purchasing at the utility's ASC, and in turn sell that acquired power to the utility at the PF Exchange rate.

Q. Are you proposing any changes in the design of the PF Exchange rate?

A. No. The design of the PF-10 Exchange rate is consistent with the PF-07R Exchange rate. That is, the Base PF Exchange rate is a single annual Energy rate applicable to all months of the year, with no Demand or Load Variance rates. In addition, the PF-10 Exchange rate includes utility-specific 7(b)(3) Supplemental Rate Charges. The 7(b)(3) Supplemental Rate Charges recover the PF Exchange allocated portion of the costs of 7(b)(2) rate protection afforded to the PF Preference rate.

Q. Are you proposing any changes in the GRSPs applicable to the PF Exchange rate?

A. Yes. As with the PF Preference rate, there are several changes to the Cost Recovery Adjustment Clause, the Dividend Distribution Clause, and the NFB Mechanisms. *See* Rodehorst, *et al.*, WP-10-E-BPA-14. Also, we are proposing minor modifications to the 7(b)(3) Supplemental Rate Charge Adjustment. The language of the Adjustment has been changed for clarification purposes. The Adjustment is now applicable for the two-year rate period, so that the loads and total REP benefits are stated as two-year values. The Adjustment includes language to affect the application of the CRAC, DDC, and

Emergency NFB Surcharge (after the clarification noted in section 1 is added). Finally, we propose language to deal with a situation where an REP participant loses or gains loads due to an annexation. This language clarifies that if an REP participant loses REP-eligible load to a consumer-owned utility and BPA's costs increase to serve this load, the REP benefits used in the Adjustment would be decreased to reflect the load lost by the REP participant. Under such conditions, the Adjustment would take effect in the month that BPA begins serving the transferred load.

Q. Could REP participating utilities have their utility-specific total PF Exchange rates change during the course of the two-year (FY 2010-2011) rate period?

A. Yes. If individual utilities place new resources in service resulting in a change in ASC; or if utilities have a change in service territory due to annexation or load transfer, as stated above; or if CRAC, DDC, or Emergency NFB Surcharge rate adjustments are implemented, BPA will establish modified 7(b)(3) Supplemental Rate Charges for all REP-participating utilities. GRSPs, WP-10-E-BPA-07, sections II.O.1. and II.O.2. Potentially, such rate changes could occur each month; however, we do not expect rate changes to be that frequent.

Section 5: Industrial Firm Power (IP) Rate and New Resources Firm Power (NR) Rate

Q. What is the IP rate?

A. The IP rate applies to BPA's power sales to direct-service industrial customers (DSIs), as defined by the Northwest Power Act, for Firm Power to be used in their industrial operations in the Pacific Northwest.

Q. What is the NR rate?

A. The NR rate applies to the purchase of Firm Power by IOUs under Northwest Power Act section 5(b) requirements contracts for resale to ultimate consumers; for direct consumption; and for Construction, Test and Start-Up, and Station Service; or by any public body, cooperative, or Federal agency to the extent such power is used to serve any new large single load, as defined by the Northwest Power Act.

Q. How are the Energy rates being calculated for the IP and NR rates?

A. We updated the marginal cost of power that is used to shape the IP and NR Energy rates. The marginal cost of power is based on the 3,500 game summary price forecast for the risk analysis as determined by the Market Price Forecast Study, WP-10-E-BPA-03A. The cost allocated to the IP rate is used to proportionately downward scale *(i.e.*, by an equal percentage applied to each rate component) the marginal cost of power at the HLH and LLH prices. *See* WPRDS, WP-10-E-BPA-05, Table 2.10 for the IP rate and Table 2.11 for the NR rate. The revenue that would be recovered using the market prices is compared to the allocated revenue requirement for the IP rate. The resulting ratio is used to downward scale the market prices to compute the IP-10 rate components. The same process is performed for the NR-10 rate components. The scaled rates then recover the portion of the total revenue requirement allocated to each class of service in total when applied to the forecast billing determinants.

Q. Are there any known changes to the IP-10 and NR-10 rates that are not currently reflected in the Initial Proposal?

A. Yes. As noted in the testimony of Brodie, *et al.*, WP-10-E-BPA-16, section 5.2, RAM2010 did not use the market prices in the scaling process. This will be changed for the Final Proposal. The effect of this pending update will be that the IP-10 and NR-10 rate components will be slightly different, but the average annual level of the rates would not change.

Q. How are the Demand and Load Variance rates calculated for the IP and NR rates?

A. We set the Demand and Load Variance rates for the IP and NR rates equal to the PF Demand and PF Load Variance rates. This is the same methodology used in WP-07

Supplemental Final Proposal, and maintains the common table of Demand and Load Variance rates.

Q. Are there any other changes to the IP and NR rates?

A. For the IP rate, yes; for the NR rate, no. We have removed the Supplemental Contingency Reserves Adjustment from the GRSPs applicable to the IP rate. This provision is replaced by a VOR credit explained in section 7 of this testimony.

Section 6: Firm Power Products and Services (FPS) Rate

Q. Are you proposing any changes to the FPS rate schedule?

A. No. The FPS energy rates will remain at negotiated rates subject to the current market conditions at the time of the negotiation. Capacity and other power services will also be at negotiated rates. In addition, we are proposing to continue to not include posted market rates for energy or capacity within the FPS rate schedule, as was the case in the FPS-07R rate schedule. We are also proposing to retain the application of the 7(b)(3) Supplemental Rate Charges to sales made under the FPS rate schedule. As outlined above, 7(b)(3) Supplemental Rate Charges will be allocated to the pool of costs that are to be recovered by FPS sales.

Section 7: Value Of Reserves—IP Rate

Q. What are reserves in the context of the IP rate?

A. The Northwest Power Act authorizes the Administrator to make sales to DSIs and provides further that "[s]uch sales shall provide a portion of the Administrator's reserves for firm power loads within the region." 16 U.S.C. § 839c(d)(1)(A). As defined by the Northwest Power Act, reserves for such sales are "electric power needed to avert particular planning or operating shortages for the benefit of firm power customers of the Administrator and available to the Administrator . . .from . . . rights to interrupt, curtail, or otherwise withdraw, as provided by specific contract provisions, portions of the electric power supplied to [DSI] customers." 16 U.S.C. § 839a(17).

Q. Why are reserves important to the IP rate?

A. Section 7(c)(3) of the Northwest Power Act provides that "[t]he Administrator shall adjust such rates to take into account the value of power system reserves made available to the Administrator through his rights to interrupt or curtail service to . . . direct service industrial customers." 16 U.S.C. § 839e(c)(3).

Q. Please describe the source of the information you relied on to define the manner in which reserves would be provided by DSIs for the rate period.

A. We relied on an unsigned long-term contract that BPA negotiated with Alcoa, which included a section dealing with how reserves might be provided by Alcoa. For the reasons described below, this provision has been adopted as the model for this portion of the rate proposal.

Q. Please describe why the study used information that is in an unsigned contract.

A. While BPA Transmission Services currently has responsibility for any stability reserves provided by DSI customers, and may have dealt with that issue more recently, BPA Power Services has not calculated a credit for DSI reserves since 1996, opting since that time to leave open the option of negotiating bi-laterally with DSIs for reserves. Because DSI load has declined substantially since 1996, and operating levels at existing smelters are at far less than full operational capacity, we believe that it would be best for ratemaking to use the agency's most current thinking on the subject of DSI reserves. While the Alcoa contract negotiations did not ultimately lead to a signed contract, several drafts were subject to significant public comment, which included the issue of DSI reserves, and the most recent contract draft has been posted on BPA's Web site. Thus, many rate case parties are already familiar with the contract proposal. Moreover, to our knowledge, BPA has not articulated a current DSI reserve policy elsewhere. For these reasons, we believe the contract provision is a reasonable model for the Initial Proposal, even though the contract with Alcoa ultimately was not signed by the parties.

Q. Is it possible that BPA's proposed approach to DSI reserves will continue to evolve during the course of this proceeding?

A. Yes. Our understanding is that the contractual provision used as the model for DSI reserves is only one part of a complex negotiating process. It is not clear whether the provision captures the maximum level of reserves that could be provided by Alcoa or the only manner in which reserves could be provided by Alcoa. Furthermore, to the panel's knowledge, there have been no prior negotiations with the other remaining DSIs, Port Townsend and CFAC, that dealt with the reserves issue. It is possible that those two DSIs might have different capabilities with respect to providing reserves. The rate case process may well elicit more and better information that will allow us to more fully assess the capabilities of the DSIs to provide reserves. To that extent, we will consider the alternatives presented on the record of this case in formulating our final proposal.

Q. Please describe the quantity of reserves you have included in the VOR analysis for this rate proceeding.

A. The contractual provision, had it ultimately been agreed upon, would have required provision of within-hour balancing reserves equal to 10 percent of the Alcoa load net of wheel-turning load. These reserves would have been limited to a maximum of 60 minutes per use and a maximum of 4 uses per month. BPA would have expected to call on these reserves to supply Supplemental Operating Reserve. Because Operating Reserve must be provided out of a power system for a maximum of 105 minutes to comply with WECC criteria, we have derated the DSI reserves to account for their limited availability.

Q. Please describe how the reserves would be used if DSI contracts do not provide the required 105-minute availability.

A. The within-hour balancing reserves provided for in the draft contract would have been used to provide Supplemental Operating Reserve. Because deployments can last longer than the reserves provided by the DSIs, we recognize that BPA would need to combine these reserves with other reserves. The capacity displaced by the reserves provided by the DSIs could be used to make a sale or provide additional reserves.

Q. Please describe how you valued the reserves from DSIs.

A. We valued the DSI reserves by using the unit rate of $7.19 per kW per month for supplemental Operating Reserve proposed in this rate proceeding. WPRDS, WP-10-E-BPA-08, section 3. Because the reserves provided may be less valuable than Supplemental Operating Reserve, we propose to derate the value of these reserves.

Q. Please describe how you derated the value of the DSI reserves.

A. The proposed method of derating is to compute the expected available reserve amount, which is 10 percent of the net load, to determine the quantity, and further reduce this quantity by the amount of time it would be required to be available *(i.e.,* four hours per month). We calculate the derating by dividing these four hours by 730 hours per month, resulting in 0.55 percent. We then multiply the quantity available by this percentage, and then multiply the product by 12 months per year to compute the total monthly kW of capacity per year available from the DSI reserves.

Q. Please describe how the IP rate is adjusted to reflect the value of these reserves.

A. The value of the reserves in total dollars per year is divided by the expected total annual DSI load in MWhs, which results in a dollar per MWh amount. WPRDS, WP-10-E-BPA-05, section 2.2.1.

Section 8: Low Density Discount

Q. What changes are proposed for the LDD section of the WPRDS?

A. The only change we propose to make to the LDD section of the WPRDS is to update the costs of the LDD for the rate period. For FY 2010, the cost of the LDD is $28.3 million, and for FY 2011, it is $28.6 million. We propose no other changes.

Q. Why have the costs of the LDD changed in FY 2010 and FY 2011?

A. The estimated costs of the LDD for FY 2010 and FY 2011 have changed because of changes in forecast loads and changes in the level of the LDD for some customers.

Q. Does this conclude your testimony?

A. Yes.