INDEX

TESTIMONY of

RAYMOND D. BLIVEN AND VALERIE A. LEFLER

Witnesses for Bonneville Power Administration

SUBJECT: POWER RATES POLICY

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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 WP-10-Q-BPA-06.

A. My name is Valerie A. Lefler, and my qualifications are contained in WP-10-Q-BPA-36.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to provide the context and background to the policy objectives for the WP-10 Initial Proposal.

Q. How is your testimony organized?

A. Our testimony contains 11 sections. The first is this introduction. Section 2 provides an overview of the WP-10 Initial Proposal. Section 3 reviews the various statutes, policy decisions, and processes that shape the Initial Proposal. Section 4 provides the financial and policy objectives that guide the development of the Initial Proposal and discusses liquidity tools. Section 5 describes the assumption regarding service to the direct-service industrial (DSI) customers used to develop the Initial Proposal, and how the assumption is reflected in the rate studies. Sections 6 through 11 review the rate studies and describe policy guidance and major issues associated with those studies.

Section 2: Overview of the WP-10 Initial Proposal

Q. Please describe the WP-10 Initial Proposal.

A. In the Initial Proposal, the proposed average Priority Firm Power (PF) rate for FY 2010-2011 is 29.4 mills/kWh, 9.4 percent higher than the average PF rate determined in the WP-07 Supplemental Final Proposal for FY 2009. The proposed Slice rate is 9.5 percent higher than the WP-07 Supplemental Slice rate for FY 2009. For details on the calculation of the rates, *see* Wholesale Power Rate Development Study (WPRDS), WP-10-E-BPA-05, and Brodie, *et al.*, WP-10-E-BPA-16. Residential Exchange Program (REP) benefits for investor-owned utilities (IOUs) participating in the REP are proposed to continue at about the same level as in FY 2009. *Id.* The proposal also maintains substantial progress toward recovering Lookback Amounts from IOUs for repayment of the 2002-2007 overpayments resulting from REP settlement agreements. Eligible PF Preference customers would continue to receive about the same level of credits on their power bills as a return of the Lookback Amounts. For details on the calculation of the recovery of Lookback Amounts, *see* Lookback Recovery and Return Study, WP-10-E-BPA-09, and Evans, *et al.*, WP-10-E-BPA-19.

Q. What increases are proposed for other rates?

A. The Initial Proposal average Industrial Firm Power (IP) rate is 36.4 mills/kWh, 4.5 percent higher than the FY 2009 IP rate. The Initial Proposal New Resource Firm Power (NR) rate is 69.7 mills/kWh, 1.9 percent higher than the FY 2009 NR rate.

Q. Are there any new major objectives included in this rate proposal?

A. We are entering the last two years of the Subscription contracts, and all of BPA's preference customers have signed new, long-term contracts that commence deliveries in FY 2012. These new contracts call for a completely new rate design, tiered rates. Because of the major changes coming in two years, we directed staff to confine changes in this rate proposal to only those that are necessary. Therefore, relatively few changes are embodied in this Initial Proposal.

The most substantive changes are in the development of the costs and revenue credits arising from generation inputs for ancillary and other transmission services, summarized in Section 8. In addition, the Generation Inputs Policy testimony of Mainzer, *et al*., WP-10-E-BPA-22, explains changes that could occur during the pendency, but outside the scope, of this rate proceeding.

Q. Please discuss briefly the need for the rate increase.

A. Key drivers of the proposed power rate increase include increases in operation, maintenance, and capital costs to ensure reliability and safe operation of the Columbia Generating Station nuclear plant. The plant will also undergo an extended outage in 2011 for condenser replacement, which will increase purchased power costs to replace lost generation due to a longer than normal time out of service. Other cost increases include capital and operating costs of the hydro system to maintain and improve reliability and output, and new biological opinion requirements and implementation of Columbia Basin Fish Accords. Costs used in development of the Initial Proposal were determined in the Integrated Program Review (IPR) process described in Section 3.

Q. What other factors might affect the rate proposal between the Initial Proposal and the Final Proposal in July?

A. We are concerned that poor net secondary revenues due to continued low water and low prices during this year (FY 2009) will exert upward pressure on the proposed power rates. Expected modified net revenues are currently projected to be well below those assumed in the Initial Proposal. For details on the calculation of the expected revenues in FY 2009 included in the Initial Proposal, *see* WPRDS, WP-10-E-BPA-05, and Hyde *et al*., WP-10-E-BPA-20.

Section 3: Sources of Policy Guidance For Rate Development

Q. Please describe the relationship between BPA's Subscription Strategy and this rate case.

A. BPA's Power Subscription Strategy established the basis for power sales contracts to be developed and offered to BPA's customers for the period October 1, 2001, to September 30, 2011. BPA's Power Subscription Strategy and the accompanying Power Subscription Record of Decision (Subscription ROD) were issued on December 21, 1998. BPA's principal goal in the Subscription Strategy was to spread the benefits of the FCRPS as broadly as possible, to consumer- and investor-owned utilities and DSIs. The WP-10 rates will apply to sales under the Subscription contracts.

Q. Please describe the primary policy decisions and processes that shape the Initial Proposal.

A. Foremost, the policy decisions and processes must conform to applicable statutes. The primary statutes governing BPA ratemaking are the Bonneville Project Act of 1937, 16 U.S.C. § 832; the Flood Control Act of 1944, 16 U.S.C. § 825s; the Federal Columbia River Transmission System Act of 1974, 16 U.S.C. § 838; and the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), 16 U.S.C. § 839.

In addition to the statutes and the Subscription Strategy, the primary policy decisions and public processes that shape the Initial Proposal are expressed in:

1) BPA's Policy for Power Supply Role for Fiscal Years 2007-2011 Administrator's Record of Decision (dated February 4, 2005) (Near-Term Policy ROD);
2) Service to Direct Service Industrial Customers for Fiscal Years 2007-2011 Administrator's Record of Decision (June 30, 2005) (DSI ROD);
3) Final 2008 Average System Cost (ASC) Methodology ROD (June 30, 2008);
4) Short-Term Bridge Residential Purchase and Sale Agreement (RPSA) for the Period Fiscal Years 2009-2011 ROD (September 4, 2008);
5) 2009 Wind Integration Rate Case Final Proposal and ROD (June 30, 2008);
6) Columbia Basin Fish Accords RODs (May 2, 2008 and November 6, 2008);

7) Final Slice Settlement (November 27, 2006);

8) Long-Term Regional Dialogue Final Policy (July 19, 2006);

9) Integrated Program Review (IPR), for which the final close-out letter and report are dated November 14, 2008;

10) 2008 Financial Plan (July 31, 2008); and

11) 2007 Supplemental Wholesale Power Rate Case Final ROD (2007 Supplemental Final ROD) (September 22, 2008).

Together, these documents form the foundation of many of the ratemaking choices incorporated into the Initial Proposal.

Q. *Please describe the changes adopted in the Near-Term Policy ROD that provide guidance for the upcoming rate period.*

A. The Near-Term Policy ROD contained four significant changes designed to give greater certainty to BPA's load service obligations under the existing Subscription Contracts for the upcoming rate period. First, BPA set the duration of this rate period at two years, FY 2010 and FY 2011. Second, public customers who signed five-year Subscription contracts without a guarantee of the lowest cost-based PF rates for FY 2007-2011 received that guarantee, as long as those customers signed a new contract or amendment by June 30, 2005. All customers eligible for the treatment did sign contracts or amendments to ensure they continue to receive the lowest cost-based PF guarantee. Third, nearly all of BPA's "Pre-Subscription" contracts terminated at the end of FY 2006. These Pre-Subscription contracts provided a protection against the application of any adjustment to "posted" rates during the FY 2002-2006 rate period. Those customers are now taking power deliveries under their standard Subscription contracts that allow rate adjustments, and they will take service under the WP-10 rates. However, there are eight Pre-Subscription customers that receive an allocation of the output of Hungry Horse Dam until 2011 that will continue to have rate limitations. Last, the Near-Term Policy ROD

provided that any new or existing public customer whose contract expired at the end of FY 2006 could select from any of the existing standard products except Complex Partial (Factoring), Block with Factoring, or Slice. In addition, BPA resolved not to offer contract amendments that would allow changes in the power products and services purchased under a customer's 10-year Subscription contract.

Q. Please describe the guidance provided for DSI rate development for the upcoming rate period.

A. As a result of the 2005 DSI ROD, BPA offered the aluminum company DSIs power sales contracts for an aggregate 560 aMW of benefits at a capped $59 million annual cost. In addition, BPA offered, through the local public utility, a 17 aMW surplus power sales contract to Port Townsend Paper Company under BPA's Firm Power Products and Services (FPS) rate schedule (or the IP-07 rate if affordable) at a price approximately equivalent to, but in no case less than, BPA's lowest-cost PF rate. Two aluminum companies and Port Townsend Paper fulfilled requirements of the offered contracts and began taking service, or monetized service, under the offered contracts. BPA and the DSIs operated under such contracts until recently when the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit or Court) issued an opinion regarding these contracts in *Pacific Northwest Generating Cooperative, et al., v. Bonneville Power Administration*, No. 05–75638, slip op. at 16513 (9th Cir. Dec. 17, 2008) (*PNGC*). In Section 5, we explain how we propose to address this opinion in this rate case.

Q. Please describe recent changes in BPA's Residential Exchange Program (REP).

A. As a result of two Ninth Circuit decisions in which the Court invalidated REP settlement contracts between BPA and six IOUs, BPA reinstituted the REP. *Portland General Elec. Co. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007) (*PGE*) and *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007) (*Golden NW*). The Final 2008 ASC Methodology ROD, the RPSA ROD, and the 2007 Supplemental

Final ROD formed BPA's policy decisions used in the implementation of the REP. The Initial Proposal continues the REP on the basis adopted in these RODs. A few minor adjustments to the WP-07 Supplemental Final Proposal are introduced in Section 11.

Q. Please describe how the IPR interacts with the 2010 BPA rate proceeding.

A. The forecasts of program-level expenses used in the development of this Initial Proposal were determined with extensive public review during the IPR. In May 2008, BPA initiated the IPR with BPA customers and constituents to examine and receive comment on BPA's forecast of costs proposed to be used in WP-10 and TR-10 Initial Proposals. On November 14, 2008, after the conclusion of the public process, BPA issued a close-out letter that discussed the forecast of program level expenses and capital investments to be used in this Initial Proposal. Revenue Requirement Study, WP-10-E-BPA-02, Appendix A. These forecasts, with certain limited exceptions, are the basis for the development of the Initial Proposal revenue requirement. Lennox, *et al.*, WP-10-E-BPA-12.

Section 4: Financial and Policy Objectives and Guidance

Q. What are the primary financial and policy objectives that guide the development of the Initial Proposal?

A. Six major financial and policy objectives help shape the Initial Proposal. These are the same objectives that shaped the WP-07 Final Proposal. These objectives are:

1) a rate design that meets BPA financial standards, particularly achieving a 95 percent two-year Treasury Payment Probability;

2) lowest possible rates, consistent with sound business principles and statutory obligations;

3) lower, but adjustable, effective rates rather than higher, more stable rates;

4) a risk mitigation package that includes only those elements that can be relied upon;

5) financial reserves that are not built up to unnecessarily high levels; and

6) allocation of costs and credits to customers based upon product choice to the extent possible.

These objectives are interdependent and require BPA to balance competing objectives against each other when developing its overall rate design strategy. This Initial Proposal reflects Power Services' efforts to balance these competing objectives.

Q. *Please elaborate on some of the major financial and policy directives and processes that provide guidance in BPA ratesetting.*

A. In July 2008, BPA concluded a public process to update the 10-Year Financial Plan it previously adopted in 1993. The 2008 Financial Plan provides a foundation for development of new (or revisions to existing) financial policies and practices, and evaluates conditions and potential directions in four key financial areas: Access to Capital; Financial Risk Metrics; Good Year/Bad Year Financial Planning; and Cost Recovery. It also provides guidance relevant to this rate proposal.

For example, the primary element of the 1993 Financial Plan was the adoption of a 95 percent probability standard for paying the U.S. Treasury in full and on time for both years of a two-year rate period (Treasury Payment Probability or TPP). The 2008 Financial Plan, published July 2008, reaffirmed this policy. This remains a key policy directive for ratemaking and is one of the financial objectives identified earlier in this testimony.

Q. *Is there other guidance relevant to this rate proposal provided by the 2008 Financial Plan?*

A. Yes. The 2008 Financial Plan provides guidelines for BPA as it studies and develops analytical tools and metrics for liquidity needs. In the Financial Plan, BPA identified two

liquidity tools, one that is reflected in the risk modeling in this Initial Proposal and one that is not reflected in this proposal. *See* Financial Plan, July 2008, section 3.6, accessible at http://www.bpa.gov/corporate/Finance/financial_plan/BPA_Financial_Plan.pdf.

Q. What is the liquidity tool that is reflected in the Initial Proposal?

A. The liquidity tool reflected in the Initial Proposal is a new short-term Treasury liquidity facility that allows BPA to borrow up to $300 million on very short notice to cover certain operating expenses, provided BPA has available borrowing authority. In the 2008 Financial Plan, BPA noted that it would continue to analyze how to maximize the benefits of this new tool.

Q. What has BPA determined regarding the impact of the availability of this note for this Initial Proposal?

A. Although a rigorous analysis on the necessary level of liquidity reserves has not been completed, we propose that, for this Initial Proposal, the availability of the Treasury facility just mentioned would be sufficient so that no additional liquidity reserves would be needed. The $50 million level of liquidity reserves assumed in meeting TPP in previous power rate proposals has been reduced to zero. We expect to maintain this assumption in the Final Proposal. However, in the unlikely event significant changes materialize in the monthly shape of revenues and expenses, we would re-assess this assumption for the Final Proposal. The evaluation that has been done for this Initial Proposal is based on conditions expected in FY 2010 and 2011, and BPA will re-evaluate the liquidity need for subsequent periods. For a discussion on how the liquidity reserves are affected by the Treasury liquidity facility, *see* the Risk Analysis and Mitigation Study, WP-10-E-BPA-04, section 4.4.2.3.

Q. What is the liquidity tool that is not reflected in the Initial Proposal?

A. The second liquidity tool described in the 2008 Financial Plan is the Flexible PF Rate Program. BPA stated in the Financial Plan that to reduce the demand on reserves as a source of liquidity, BPA will consider whether or not to propose an extension of the Flexible PF Rate Program during the FY 2010 Power rate case. This Initial Proposal does not forecast the use of the Flexible PF Rate Program for FY 2010-2011 as a liquidity tool. This is largely due to the availability of the new Treasury facility. However, BPA will consider whether it should pursue this tool and incorporate it prior to the development of the Final Proposal. Considerations are how much liquidity is needed, how much the Flexible PF Rate Program could provide, the costs and benefits of maintaining the program, and how likely it is that BPA would achieve sufficient participation in this program from customers given the increased tightening of the credit markets. *Id.* at section 4.4.2.2; Rodehorst, *et al.,* WP-10-E-BPA-14, Section 17.

Section 5: Assumptions About Service To Direct Service Industries

Section 5.1: DSI Service Assumption for the Initial Proposal

Q. Are there any changes in assumptions regarding service to the DSIs?

A. Yes. As noted above, the Ninth Circuit's opinion in *PNGC* was issued when we were well into the Initial Proposal development process. We had begun the ratemaking process assuming that the two aluminum DSIs would continue to receive monetized benefits and that Port Townsend Paper would be served using an FPS sale through Clallam PUD. The *PNGC* opinion caused us to revisit our DSI assumptions for the Initial Proposal. Accordingly, we have modified our DSI assumptions for the Initial Proposal.

Q. What assumptions do you make regarding DSI service?

A. We directed staff to assume for ratesetting purposes an actual power sale at the IP rate to all three DSIs. However, because the Loads and Resources Study was complete and

analyses that depended on that study had commenced, we chose to reflect the IP sale at a later point in the ratemaking process. The Rate Analysis Model (RAM2010) changed the manner in which the DSIs are assumed to be served from the pre-*PNGC* conditions to an IP power sale. Further, to minimize the rate impact of this change of service assumption, we directed staff to assume service to aluminum DSIs at a level with a net cost of $59 million annually.

Q. Has BPA decided how it will serve the DSIs in FY 2010-2011?

A. No. BPA is still examining how it should apply the Court's opinion to DSI service. To the extent there is a resolution of the various issues surrounding DSI service for FY 2010-2011, this resolution will be reflected in the Final Proposal. However, issues associated with actual DSI service will be resolved in a process outside of this rate proceeding. Rate case parties who desire to participate in the DSI service determination will need to participate in the other process when it is announced.

Section 5.2: Modeling DSI Service

Q. How is the DSI service assumption modeled in the Initial Proposal?

A. Because of the late change in DSI service assumptions for the Initial Proposal, the assumed sale of power to aluminum DSIs is reflected in the WPRDS as an adjustment to IP sales and augmentation expense. The level of service to the aluminum DSIs is set to achieve a net cost of $59 million. The Rate Analysis Model computes the net cost of DSI service—the difference between increased augmentation expense and IP revenues. The sale of power to Port Townsend Paper was changed from an FPS sale to an IP sale. No change in augmentation expense was necessary for the Port Townsend change. The modeling of the IP sales to the aluminum DSIs and Port Townsend Paper is described in the testimony of Brodie, *et al*., WP-10-E-BPA-16, Section 5.1.

Q. How does the Loads and Resources Study model the assumptions regarding DSI service?

A. As noted, the *PNGC* opinion came too late in the ratemaking process to incorporate any change of assumption regarding DSI service in the Loads and Resources Study, WP-10-E-BPA-01. If the Court's opinion had been issued earlier, loads would have been increased to reflect the assumption of an actual power sale to the aluminum DSIs. Second, the Port Townsend Paper FPS sale would have been moved from a BPA contract sale to Clallam PUD, to a direct BPA IP sale to Port Townsend. Third, the amount of augmentation necessary for load-resource balance would have been increased to reflect the power sale to the aluminum DSIs. The Port Townsend change would not affect the total amount of augmentation needed, because the load-resource balance already accounts for a power sale.

Q. What changes to the final Loads and Resources Study regarding DSI service would be expected?

A. If BPA makes a determination to sell power to the DSIs, the changes outlined in the prior answer will be incorporated into the final study. If the determination is for a monetized benefit, no changes will be necessary.

Q. Does the Court's PNGC opinion on DSI service issues change any assumptions in the Revenue Requirement Study?

A. Yes. Because of the late change in DSI service assumptions for the Initial Proposal, the assumed sale of power to aluminum DSIs is reflected in the initial Revenue Requirement Study, but in an *ad hoc* manner. If the sale had been incorporated into the Loads and Resources Study and all studies further along in the ratemaking process, the monetized DSI benefit line item in the revenue requirement of about $59 million would have been set to zero and the augmentation expense line item would have increased by the $59 million. Also, the revenues from the sale to the aluminum DSIs would have been reflected in total BPA revenues. However, because the sale to the aluminum DSIs was

not incorporated, the Rate Analysis Model computes the net cost of DSI service—the difference between increased augmentation expense and IP revenues—and the revenue requirement includes this difference in the line item formerly used for the monetized benefits. No change in the Revenue Requirement Study was necessary to reflect the change in service assumptions for Port Townsend.

Q. What changes to the final Revenue Requirement Study are expected from a timely DSI service determination?

A. If BPA makes a final determination to sell power to the DSIs, the changes outlined in the prior answer will be incorporated into the final study. If the final determination is for a monetized benefit, the monetized benefit line will remain the same.

Q. Are any other issues raised by these changes in DSI service assumptions?

A. Yes. A sale of power, as opposed to a monetized benefit, raises the issue of the value of reserves provided by DSIs. Because BPA has not determined how the DSIs will be served and what reserves will be provided by the DSIs, we instructed staff to make the best assumption they can based on available sources of information. The Rate Design panel discusses the value of reserves assumptions they made and the open issues regarding value of reserves. Fisher, *et al*., WP-10-E-BPA-30, Section 7. We invite parties to the proceeding to present their views on the value of reserves for the Administrator's consideration.

Q. Does the risk analysis assess the risks of the assumed service to the DSIs?

A. No. The *PNGC* opinion came too late to incorporate DSI service assumptions into the risk analysis. When more definition is gained regarding the form of service to the DSIs in FY 2010-2011, the risk analysis staff will have better information to assess the risks attendant to such service.

Section 6: Market Price Forecast Study

Q. Are there any major changes to the Market Price Forecast Study?

A. There are no major changes to the methodology used in the Market Price Forecast Study. There are impacts on price forecasts for electricity and natural gas due to the economic downturn.

Q. Are there concerns about the Market Price Forecast?

A. During the preparation of the Market Price Forecast for the Initial Proposal, the effects of the economic downturn were becoming increasingly evident. Staff factored into their forecast a number of these effects, but the near- and mid-term future remains unclear. The efficacy of the Administration's economic stimulus package is unknown at this time. The depth and length of the recession is also uncertain. These factors have compromised the normal (copyrighted) sources of market price forecasts that are used to validate staff's market price forecasts. We believe our analysts have produced the best forecasts they can given the uncertainties seen at this time.

The next few months may provide more clarity regarding the economic future. If so, our analysts will use new information to help them produce the Market Price Forecast for the Final Proposal. However, it is unlikely that the future will be more certain before the Final Proposal. The natural gas price forecast for the Final Proposal may be based, at least in part, on variables that are not explicitly identified as part of the Market Price Forecast for the Initial Proposal or on relationships among natural gas fundamentals that are not found in the historical context. The natural gas price forecast is a primary driver of the electricity market price forecast.

We believe that it is important that the Administrator have sufficient flexibility to consider the changing economic landscape in setting rates for the next two years. Even though he has risk mitigation tools at his disposal, there are policy choices to be made in this proceeding between the level of base rates and reliance on risk mitigation tools. We

invite parties to the proceeding to present their views on these topics for his consideration.

Section 7: Risk Analysis and Mitigation Study

Q. Are there significant changes in BPA's risk exposure compared to that in prior rate periods?

A. Most of the risks BPA faces are substantively similar today to those BPA has faced for many years. However, the financial magnitude of these risks has increased due to the increased market price levels and volatility. The West Coast energy crisis bore witness to dramatic market price spikes that were unprecedented. The recent financial liquidity crisis has limited the scope of the energy market by removing trading partners without sufficient credit to meet current standards. Even though there are some market controls in place that should limit a repeat of past events, wholesale market prices for electricity today are nevertheless significantly more volatile and less predictable than those BPA experienced in the past. Given this volatility in revenue from net secondary sales, the balance among rate levels, rate volatility, reserve levels, and TPP is more challenging.

Q. Are there any new sources of risk that BPA faces today?

A. Yes. The REP has always been a significant source of risk since its inception in 1981. One risk arising from the REP is that ASCs could change after rates were established, leading to higher (or lower) costs of the REP. To mitigate this risk, BPA adopted a changing PF Exchange rate structure that adjusted rates when an ASC of a REP-participating utility changed after rates are determined. This structure is discussed by the Rate Design panel, Fisher *et al*., WP-10-E-BPA-30.

A second risk arising from the REP is the risk that actual exchange loads will differ from forecast exchange loads. If exchange loads were to be significantly higher than forecast, REP expenses could rise above the levels determined in the rate

proceeding. This risk is not addressed in the Initial Proposal. There was insufficient time from the end of the WP-07 Supplemental proceeding in September 2008 to this Initial Proposal to include this risk into the risk analysis. Preliminary estimates of normal load risk due to the load risk factors already captured in the risk analysis indicate that the exchange load risk is in the range of plus or minus $10 to 15 million per year.

Q. Are there additional risks that might be associated with service to DSIs?

A. There may be, but with the method of service to DSIs being undetermined at this time, it would be speculative to state the extent of the risks associated with DSI service.

Q. Are there revisions to the risk analysis methodology?

A We are proposing to include augmentation cost risk in the Initial Proposal. As set forth in Rodehorst, *et al.*, WP-10-E-BPA-14, Section 3.9, augmentation cost risk has been treated in several different ways in previous rate cases, whether through the LB CRAC or not at all. In this Initial Proposal, the amounts of needed system augmentation are significant, 372 aMW in FY 2010 and 599 aMW in FY 2011 (both levels are after recognizing the purchase of Excess Requirements Energy (ERE) from some Slice customers).

Because system augmentation is the purchase of power to bring annual resources into balance with annual loads, it is considered an annual firm power purchase. The forecast prices for these purchases to determine the revenue requirement for system augmentation reflect the purchase of annual blocks of power. The use of market prices of electricity based on 1937 water conditions appears to be a good estimate of prices for firm blocks of power.

Thus, we directed the risk analysis staff to incorporate the cost risk attendant to the purchase of system augmentation. We recognize that the composition of the augmentation needed in FY 2011 differs from the augmentation needed in FY 2010. About 40 percent of the needed system augmentation in FY 2011 results from an extended outage of the Columbia Generating Station for a condensor replacement. We

also recognize that over the past few years, BPA has been successful in managing this risk without the purchase of firm blocks of annual power. As a result, we instructed staff to recognize these factors when constructing an assessment of augmentation cost risk. Accordingly, the system augmentation is divided into three subsets to allow differing risk treatments. The first subset is the augmentation associated with the CGS outage. This risk should recognize the timing of the outage and that annual blocks of power are not necessarily the most cost effective way of purchasing for this need. The second and third subsets comprise the remaining FY 2011 augmentation and all of the FY 2010 augmentation. Here, staff was asked to divide these augmentation amounts in half and treat one half as an annual firm block of power and treat the other half as purchases when the need arises depending on load and resource conditions in the heavy and light load hour time periods for each month. The latter subset is called self-augmentation, as a convenient label. *See* Rodehorst, *et al*., WP-10-E-BPA-14, for a discussion of the methods used by the risk analysis staff.

Section 7.1: BPA's Risk Mitigation Package

Q. Generally describe the risk mitigation package in the Initial Proposal.

A. The risk mitigation package in the Initial Proposal is similar to that in the WP-07 case. It includes a combination of reserves, PNRR to augment reserves, a CRAC, and a Dividend Distribution Clause (DDC). The CRAC, DDC, and NFB Mechanisms are available for adjusting rates during the rate period. The various details surrounding the risk package are described in more detail in the testimony of Rodehorst, *et al*., WP-10-E-BPA-14, and the Risk Analysis Study, WP-10-E-BPA-04. In addition, if events occur that dramatically affect BPA's finances, BPA retains the ability to initiate a new rate case to reset rates to deal with this change.

Q. Why did you choose this risk mitigation package for the Initial Proposal?

A. The combination of reserves, PNRR, a CRAC, NFB Adjustment, and a DDC would present BPA with a reasonable mix of fixed and flexible tools and balances the competing policy objectives stated in Section 4. The selected package would allow BPA to meet its TPP standard without setting "posted" rates at an unacceptably high level or building up significant cash reserves in the FY 2010-2011 rate period. The initial rate will be lower and more volatile than the rate resulting from a risk package that relied less on adjustable mechanisms and more on fixed ones. This is in line with our understanding of customer preferences. Additionally, this set of risk mitigation tools relies only on tools that BPA can rely on with a very high degree of certainty, reducing the risk that the mitigation itself could fail.

Q. Are there changes to the risk mitigation tools?

A. As described in Section 4, because of the availability of a new Treasury borrowing facility, this Initial Proposal assumes that facility would be sufficient so that no additional liquidity reserves would be needed. In addition, the CRAC, DDC, and Emergency NFB Surcharge have been revised so that they affect REP benefits. *See* Rodehorst, *et al.*, WP-10-E-BPA-14, Sections 11-14.

Section 7.2: Alternative Risk Mitigation Tools

Q. In developing the Initial Proposal, did you consider tools that are not proposed?

A. Yes. As discussed in Section 5, there are two specific risk mitigation tools that could provide BPA with additional risk mitigation. The Flexible PF Rate Program is not abandoned, but neither is it modeled in the Initial Proposal. As discussed above, its use is under consideration. Rodehorst, *et al.*, WP-10-E-BPA-14, Section 17.

Another potential tool we did not include but continue to analyze is availability of agency reserves. In the WP-07 Final Proposal, it was assumed, for the purpose of setting

power rates, that cash reserves attributed to Transmission Services in excess of the level required to maintain a 95-percent TPP standard for the remainder of the FY 2006-2007 transmission rate period would be available for Power Services to draw upon in FY 2007. In this Initial Proposal, no assumption has been employed regarding the availability of Transmission's cash reserves for Power ratesetting. We are concerned that the use of agency reserves be properly incorporated as a risk mitigation tool such that the same reserves are not being used for more than one purpose. For a more in-depth discussion on the use of and concerns about agency reserves, *see* Rodehorst, *et al*., WP-10-E-BPA-14, Section 9.

Q. Why are you not assuming availability of transmission cash reserves for the Initial Proposal?

A. There are several differences between the circumstances of the WP-07 power rate case and this rate case. Power and Transmission Services are setting rates concurrently, and there are concerns about how such an assumption could be made to work. *Id*. We will consider whether there are sufficient reserves available and whether the identified concerns and other issues raised in the rate proceeding can be addressed adequately to assume use of Transmission cash reserves for the final Power rate proposal. BPA is motivated to explore all means of minimizing the rate increase.

Q. Are there any other risk analysis or mitigation alternatives that were considered?

A. Yes. Our concern about the level of secondary revenue credit produced through the ratesetting methodology gives us concern, especially since eight of the nine most recent water years are below the average for the 70-year record. Rodehorst, *et al*., WP-10-E-BPA-14, Section 16. We considered a reweighting of the 70 historical water years used in the rate development processes to capture some of this concern. Ultimately, we decided not to propose such reweighting in the Initial Proposal. *Id.*

Section 8: Generation Inputs Study

Q. What is the Generation Inputs Study?

A. The Generation Inputs Study, WP-10-E-BPA-08, is a new study in this rate case. In past rate cases, generation inputs were a relatively small issue and were included in the WPRDS. Due to several new proposals, generation inputs have risen in importance and garnered more focus. To make it easier for parties interested in generation inputs issues to find the discussion and documentation, we have moved the generation inputs topics into a separate study.

Q. What new proposals led to the increased importance of generation inputs?

A. First, the amount of the revenue credit from the generation inputs has increased almost three-fold, in part due to proposed changes in the allocation of costs to generation inputs. Second, the increase in wind generators interconnected to BPA's transmission grid has multiplied the effect of generation variability on BPA's power system. These issues are discussed more fully by the Generation Inputs Policy panel, Mainzer, *et al*., WP-10-E-BPA-22.

Q. Do you expect any major generation inputs issues?

A. Yes. We expect the amount of generation reserves assumed in the ratesetting methodologies to be the focus of much interest and discussion. Because of the amount of time that it takes staff to prepare a complete rate proposal, the Initial Proposal assumes a specific amount of capacity reserves being held out for generation and load regulation, following, and balancing. Generation Inputs Study, WP-10-E-BPA-08, section 2. In the Initial Proposal, the reserves amount held for wind generation imbalance is consistent with scheduling at a 2-hour persistence level. BPA has been in discussion with wind generators, wind advocacy groups, investor-owned utilities, and consumer-owned utilities concerning the operational attributes of wind generation. While the resolution of operational decisions will not be made in this rate proceeding, those decisions will inform the assumptions used for generation inputs in the Final Proposal. The Generation Inputs

Policy panel describes these processes and the effects of their outcome on the generation inputs revenue credit. Mainzer, *et al*., WP-10-E-BPA-22.

Section 9: Wholesale Power Rate Design Study

Section 9.1: Rate Design

Q. Are there any major rate design changes in the Initial Proposal?

A. No. Because this is the last rate period under Subscription contracts, and a total restructuring of rate design will occur two years hence, we have instructed staff to limit rate design changes to only those absolutely necessary. Therefore, the proposed changes are few in number and have little effect. We have proposed to apply the PF rate design methodology adopted in the WP-07 Final Proposal to this case, so Energy, Demand, and Load Variance rates are increased by an equal percentage determined by the change in total costs allocated to the PF rate pool. This method and other minor changes are discussed by the Rate Design panel, Fisher, *et al.,* WP-10-E-BPA-30.

Section 9.2: The Slice Rate

Q. Are there any issues regarding the Slice rate?

A. Yes. Late in the ratemaking process, BPA staff discovered a problem resulting from the implementation of the Slice Settlement that creates a rate increase for non-Slice customers. The problem arises from a forecast of the Slice True-Up Adjustment Charge. A fundamental tenet of the Slice rate is that offering the Slice product will not create cost shifts between Slice and non-Slice customers. It appeared to us that an increase in non-Slice rates solely attributable to the Slice Settlement could be viewed as a cost shift.

Q. What is the Slice Settlement?

A. BPA negotiated a change to the Slice True-Up process as a result of the Slice Settlement (07PB-12273) BPA signed with Slice customers and Northwest Requirements Utilities on

November 22, 2006. Further explanation of the Slice Settlement can be found in the testimony of Johnson, *et al*., WP-07-E-BPA-59, Section 2. The Slice Settlement provided, in part, for a change in the way that the Slice True Up would be calculated, beginning in FY 2007.

Q. Please describe the cost-shift issue arising from the forecast Slice True-Up Adjustment Charge.

A. The Slice Settlement provides that the Slice rate for each year will be trued up to the average rate period expenses. Because expenses in the Initial Proposal are lower in the first year and higher in the second year, we forecast that Slice customers would receive True-Up payments for FY 2010 and owe True-Up payments to BPA in FY 2011. Under the Slice contract, the True-Up payments from Slice customers for FY 2011 are not due to be paid to BPA until early FY 2012. Collecting payments for the Slice True-Up Adjustment Charge from Slice customers outside of the FY 2010-2011 rate period is problematic in that the cash lag results in more cash required from other customers in FY 2011.

Q. Why does the lag in cash payments result in a cost shift to non-Slice customers?

A. This cash payment lag for the forecast FY 2011 Slice True-Up Adjustment Charge results in an increase in the PNRR that is included in the PF Preference rate. Lee, *et al*., WP-10-E-BPA-21, Section 4.

Q. How do you propose to eliminate this cost shift to non-Slice customers?

A. We propose to eliminate the cost shift to non-Slice customers by shifting particular expenses from FY 2011 to FY 2010 in the Slice Revenue Requirement so that the forecast of the FY 2011 Slice True-Up Adjustment Charge is zero. When the forecast of the FY 2011 Slice True-Up Adjustment is zero, then the related effect on the level of PNRR is eliminated. *Id.*

Q. Are there other solutions to this problem?

A. We expect that there are. For example, if the Slice True-Up calculation compared the Slice Revenue Requirement for a fiscal year to the Actual Slice Revenue Requirement for that year, this problem would be eliminated. However, this solution is inconsistent with the Slice Settlement, and we therefore are not proposing this solution. Because the discovery of this problem came very late in the ratesetting process, we have not had time to seek input from BPA's customers or to develop other possible solutions. We are hopeful that a mutually acceptable resolution of this issue can be found by opening a dialogue with rate case parties during this rate proceeding.

Section 9.3 *Ad Hoc* Adjustment

Q. What is the ad hoc adjustment?

A. The *ad hoc* adjustment effectively reduces the revenues expected from wind generation for the integration services provided by reserves from Federal system resources. Ongoing discussions with wind generators, utility customers, and interested parties hold promise that operational solutions will be adopted that will allow for fewer required reserves for integrating wind resources in the BPA Balancing Authority Area (BAA). The *ad hoc* adjustment reflects the direction that the discussions appear to be heading.

Q. Please explain the ad hoc adjustment in the generation inputs revenue credit.

A. As explained in Section 8, the Initial Proposal is based on an assumed amount of reserves from Federal system resources held for wind integration that is consistent with a 2-hour persistence scheduling assumption. BPA has been in discussion with wind generators, wind advocacy groups, investor-owned utilities, and consumer-owned utilities concerning the operational attributes of wind generation and the potential tools that would limit the amount of reserves held for wind integration. If the operational considerations regarding wind integration and scheduling can be resolved at less than the 2-hour persistence

scheduling level, the generation inputs revenue credit would decrease. To reflect the likelihood that the final rate proposal may be based on a wind persistence scheduling level of less than 2 hours, we have included an *ad hoc* adjustment to the revenue credit so that power rates will not be significantly changed from proposed levels due to the final wind operations decisions.

Q. What is the size of the ad hoc adjustment?

A. The *ad hoc* adjustment is $34.6 million per year. It represents the estimated reduction in the wind integration revenue credit assuming an average revenue credit resulting from a 45-minute wind persistence scheduling level and a 30-minute wind persistence scheduling level, all else being equal. The *ad hoc* adjustment is included in the PF, IP and NR rates. WPRDS, WP-10-E-BPA-05, section 3.2.4.9.

Q. Could the operational decisions result in increases to power rates greater than what is reflected in the Initial Proposal?

A. The current estimate of the maximum reduction in revenue credits is about $40 million. Generation Inputs Study, WP-10-E-BPA-08, Table 3.8. Thus, generation inputs revenue might be reduced another $5 million per year, all else being equal. This further adjustment would have a very small effect on power rates. On the other hand, operations decisions may lead to the Final Proposal generation inputs revenue credit being higher than the effective revenue credit with the *ad hoc* adjustment in the Initial Proposal, leading to slightly lower power rates.

Q. Will there be an ad hoc adjustment in the Final Proposal?

A. The *ad hoc* adjustment will not be part of the Final Proposal. All of the Final Proposal studies will use an amount of reserves consistent with the final operations decisions. Therefore, the final rates will be determined in accordance with the operations decisions, and no *ad hoc* adjustment will be necessary.

Section 10: Section 7(b)(2) Rate Test Study

Q. How is the Initial Proposal related to the WP-07 Supplemental proceeding?

A. The Initial Proposal is built upon the decisions made in the 2007 Supplemental Final ROD. For the most part, we have continued to apply these decisions in this Initial Proposal.

Q. What changes are you proposing in the Section 7(b)(2) Rate Test?

A. We are proposing two minor changes in the Initial Proposal. First, we propose modifying the Section 7(b)(2) Implementation Methodology to change the rounding of the trigger from one decimal place to two decimal places. Second, we propose some clarifications regarding the identification of resources included in the 7(b)(2)(D) resource stack. These changes are discussed by the 7(b)(2) Rate Test panel, Doubleday, *et al*., WP-10-E-BPA-15.

Section 11: Lookback Recovery and Return Study

Q. What is the Lookback Recovery and Return Study?

A. The Lookback Recovery and Return Study, WP-10-E-BPA-09, documents how much of the Lookback Amount is expected to be recovered from the IOUs and returned to eligible customers in FY 2010-2011.

Q. What is a Lookback Amount?

A. The Lookback Amounts arose from decisions made by the Administrator in the 2007 Supplemental Final ROD. They are REP settlement benefits that the Administrator determined were paid to IOUs in excess of REP benefits that would have been allowed under application of sections 5(c) and 7(b) of the Northwest Power Act. Evans, *et al*., WP-10-E-BPA-19, Section 2. This Initial Proposal recognizes the Administrator's decisions in the 2007 Supplemental Final ROD and continues to implement the decisions in a manner consistent with his decisions.

Q. Are you proposing any substantive changes in the Lookback recovery and return?

A. No. There are some minor corrections described by the Lookback panel, Evans, *et al.*, WP-10-E-BPA-19, Sections 3 and 7.

Q. Are there any changes expected before the Final Proposal is completed?

A. BPA has proposed a settlement with Avista regarding its deemer account balance, which is undergoing a review and comment process. Depending on the outcome of that process, Avista's deemer balance may be altered from the assumption used in the WP-07 Supplemental proceeding. The Lookback panel describes the potential effects of the proposed settlement. Evans, *et al*., WP-10-E-BPA-19, Section 8.

Q. Does this conclude your testimony?

A. Yes.