2010 Initial Transmission Proposal

Direct Testimony and Qualifications Statements

TR-10-E-BPA-04 through TR-10-E-BPA-08
TR-10-Q-BPA-01 through TR-10-Q-BPA-16

February 2009

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Bonneville Power Administration
Transmission Services

2010 INITIAL TRANSMISSION PROPOSAL

DIRECT TESTIMONY AND

QUALIFICATION STATEMENTS

DIRECT TESTIMONY

BPA Exhibit No.	Subject	Witness
TR-10-E-BPA-04	Revenue Forecast	Chen, Contreras, Davis Fredrickson, Messinger
TR-10-E-BPA-05	Revenue Requirement	Homenick, Jensen Lennox, Lovell
TR-10-E-BPA-06	Overview of Partial Settlement	Bermejo, Elizeh, Jackson, Pearson
TR-10-E-BPA-07	Ancillary Services and Control Area Services	Bermejo, Chen Gilman, McManus, Messinger
TR-10-E-BPA-08	Incremental Cost Rate	Jackson, King Lennox

QUALIFICATION STATEMENTS

TR-10-Q-BPA-01	Sarah K. Bermejo
TR-10-Q-BPA-02	Danny L. Chen
TR-10-Q-BPA-03	Araceli C. Contreras
TR-10-Q-BPA-04	Reed C. Davis
TR-10-Q-BPA-05	Edison G. Elizeh
TR-10-Q-BPA-06	Rebecca E. Fredrickson
TR-10-Q-BPA-07	David L. Gilman

TR-10-Q-BPA-08	**Ronald J. Homenick**
TR-10-Q-BPA-09	**Mark A. Jackson**
TR-10-Q-BPA-10	**Dana M. Jensen**
TR-10-Q-BPA-11	**Robert D. King**
TR-10-Q-BPA-12	**Alexander Lennox**
TR-10-Q-BPA-13	**Byrne E. Lovell**
TR-10-Q-BPA-14	**Bartholomew A. McManus**
TR-10-Q-BPA-15	**Ronald E. Messinger**
TR-10-Q-BPA-16	**Terrin L. Pearson**

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TESTIMONY OF

DANNY L. CHEN, ARACELI C. CONTRERAS, REED C. DAVIS,
REBECCA E. FREDRICKSON and RONALD E. MESSINGER

Witnesses for Bonneville Power Administration

SUBJECT: REVENUE FORECAST

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TESTIMONY OF

DANNY L. CHEN, ARACELI C. CONTRERAS, REED C. DAVIS,

REBECCA E. FREDRICKSON AND RONALD E. MESSINGER

Witnesses for Bonneville Power Administration Transmission Services

SUBJECT: REVENUE FORECAST

Section 1: Introduction and Purpose of Testimony

Q. Please state your name and qualifications.

A. My name is Rebecca E. Fredrickson. My qualifications are stated in TR-10-Q-BPA-06.

A. My name is Ronald E. Messinger. My qualifications are stated in TR-10-Q-BPA-15.

A. My name is Reed C. Davis. My qualifications are stated in TR-10-Q-BPA-04.

A. My name is Danny L. Chen. My qualifications are stated in TR-10-Q-BPA-02.

A. My name is Araceli C. Contreras. My qualifications are stated in TR-10-Q-BPA-03.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor and describe Bonneville Power Administration (BPA) Transmission Service' (TS) revenue forecast for Fiscal Years (FYs) 2010-2011.

Q. How is your testimony organized?

A. This testimony is organized in three sections. Section 1 is this introduction. Section 2 describes the development of the sales forecast that is summarized in the Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, at Table 14-1. Section 3 describes the revenue forecast and presents a summary of revenues under current and proposed rates. *Id.* at Table 14-2 and Table 14-3.

Section 2: Transmission Sales

Q. How are transmission sales forecast?

A. Sales are forecast for each transmission service TS offers. Sales over the Network segment of the federal transmission system are distinguished from those over the Southern Intertie segment and the Montana Intertie. Additionally, BPA separately forecasts long-term and short-term sales; and within long-term, contract-demand (e.g., Point-to Point service) and load-based (Network Integration service) sales.

Q. Has use of the transmission system changed since the revenues were forecast for the 2008 transmission rate case?

A. Yes. The execution of new, long-term Point-to-Point (PTP) Service Agreements has continued to increase since the revenue forecast was developed for the 2008 transmission rate case. New generation in BPA's Balancing Authority Area has also fueled an increase in long-term transmission service contracts. Network Open Season reservations that were enabled and offered service without needing new or additional infrastructure during the current fiscal years through FYs 2010 and 2011 have added to the revenue forecast. In addition, expected sales from our new reservation process for Conditional Firm Service were included. The forecast is shown in Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, Table 14-1.

Q. What are the significant sources of revenue that influence sales forecasts?

A. The sales forecasts are based primarily on revenues received for services provided under BPA's Open Access Transmission Tariff (OATT) for load-based Network Integration (NT) service and contract-demand based PTP service. Sales are forecast for both long-term PTP service (one or more years' duration) and for short-term PTP service (less than one year's duration). TS offers PTP service on the Network, Southern Intertie, and Montana Intertie segments of the Federal transmission system. Sales are also forecast for long-term service on the Network segment of the transmission system that is provided under legacy, contract-demand based Formula Power Transmission (FPT) and Integration of Resources (IR) contracts. We expect that these legacy contracts will convert to PTP service when they expire. Utility Delivery Charge and ancillary services sales are also forecasted.

Q. *How does BPA forecast the demand portion of its load-based NT sales?*

A. The forecast analysts develop two primary factors to assist them in forecasting load-based NT demand. First, using a regression-based statistical approach, the analysts input the customer's historical metered data for each POD into their forecast model to calculate the customer's forecasted monthly system peak for that POD. The analysts may further adjust the forecasted monthly system peak to incorporate the customer's anticipated load growth.

Next, for each month, the analysts determine the customer's load at that POD at the time of BPA's transmission system peak. The analyst divides that figure by the POD's system peak for the month (determined from the customer's historical data). For example, if the customer's load at that POD at the time of BPA's transmission system peak is 80 MW and the customer's monthly system peak for that POD is 100 MW, the ratio is 80/100 or .80. This ratio may be modified by the forecast analysts to account for unusual activity that impacts the ratio's calculation, e.g., the historical data used may reflect significantly abnormal loads, weather, or other activity.

The forecasted monthly system peak for that customer's POD, determined above, is multiplied by the ratio to determine the forecasted monthly system peak at the time of BPA's transmission system peak. Using the example above, if the forecasted monthly system peak for the customer's POD is 110 MW (up from the actual 100 MW), the customer's expected load at the time of BPA's overall TSP would be 110 MW x .8 or 88 MW.

To forecast BPA's total NT sales, this process is repeated for each customer's POD. The forecasted loads for each customer's PODs at the time of BPA's transmission system peak are added together. The sum equals total forecast NT sales.

Q. *Is this process different than that BPA has used in the past?*

A. Yes. In prior rate cases, the customer's POD load forecasts were based on a historical average of the customers' historical POD billing data from the most recent four-year period. These historical data were escalated using the BPA White Book expected growth rates by customer class. Peak load forecasts for federal agencies, non-generating publics, and generating publics from the White Book Capacity Table A-1, Total Retail Loads were used (*see* 2007 Pacific Northwest Loads & Resources Study, The White Book, Technical Appendix Volume 1, Energy Analysis, at Table A-1).

Q. *Why did BPA change processes?*

A. First, the new method allows BPA to explicitly model the effects of weather on the forecast produced for each customer. In addition, the new method is applied in an agency-wide forecasting tool. Efficiencies are gained from using a uniform forecast method for both the power and transmission business units. Furthermore, this method assures that consistent information is used for all BPA planning. And, as BPA gathers more data, it can use the regression approach to explicitly model the effects of various independent variables, such as weather and change in resources, on total retail load.

Q. *How is the Utility Delivery Charge sales forecast developed?*

A. Customers served through low-voltage PODs are assessed a Utility Delivery Charge. Low-voltage PODs in this instance are those PODs where TS owns the transformer and the transformer's low-side voltage is less than 34.5kV. The Utility Delivery Charge is based on loads forecasted by BPA forecast analysts at the low-voltage PODs. For PODs where the substation is expected to be sold during the rate period, the sales forecasts for those loads were removed in for FY 2011. For the Utility Delivery Charge forecast, *see* Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, at Table 14-1, line 20.

Q. What other long-term products does TS sell on its network?

A. TS sells long-term, contract-demand service under its FPT, IR, and PTP contracts. These contracts provide long-term service billed based on transmission demand.

Q. How is the forecast of long-term transmission demand for these products developed?

A. First, we develop a base forecast by summing the transmission demands of each executed PTP, FPT, and IR contract that commences service before or during the rate period. These transmission demands are summed for each month of the forecast period extending through the end of the rate period. The transmission demand of each PTP contract without rollover rights and with an expiration date prior to the end of the rate period is forecast as zero for each month after expiration. The transmission demand of each FPT and IR contract with an expiration date prior to the end of the rate period is forecast as zero for each month after expiration. Any IR short-distance discount is included in the IR contract demand. PTP short-distance discounts for executed contracts are also summed for each month the contracts are executed. Thus, the forecast of executed contracts is the base level of future sales secured by contract. *See*

Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, at Table 14-1, line 10.

Second, all FPT and IR contracts expiring during the rate period are assumed to convert to PTP service. The transmission demands of those converted contracts are included in the sales forecast.

Third, each expiring PTP contract eligible to rollover its service pursuant to section 2.2 of the OATT is assumed to roll over and for service to continue through the rate period. The transmission demands of those PTP contracts forecasted to exercise rollover rights are summed and added to the forecast. *Id.* at Table 14-1, line 8.

Fourth, for each PTP contract whose holder has exercised its right to extend the commencement date of the PTP contract pursuant to section 17.7 of the OATT, we forecast the contract holder will continue to exercise its section 17.7 rights for the full five years permitted by the OATT. We subtract from the total forecast the transmission demands of those contracts whose commencement of service dates are extended. *Id*. at Table 14-1, line 8.

Fifth, we forecast the amount of new, long-term PTP sales to be made before or during the rate period. Part of this forecast includes transmission service that is anticipated due to the completion and integration of new generation pursuant to a Large Generation Interconnection Agreement (LGIA). In developing this forecast, we assume that those LGIAs not connected with a service request will request service equal to 50% of the facility's nameplate capacity. *Id.* at Table 14-4, line 24-33. This assumption is based upon our experience with generators.

Q. *How are LT PTP sales forecast on the Network and Interties?*

A. TS bases its forecast of long-term PTP Network sales on several elements. We added demands from current long-term contracts effective through the FY 2010-2011 rate period, plus confirmed OATT 17.7 customer deferrals (extension of commencement of service), plus sales from BPA TS' Network Open Season. For Network Open Season, only those reservations authorized without new or additional infrastructure for service taken during the rate period were included in the forecast.

TS' forecast of long-term PTP Network sales includes long-term sales that have not been requested yet but are expected to occur, such as OATT 2.2 renewals and OATT 17.7 deferrals, during the 2010 and 2011 rate period. This aspect of the forecast is developed through input received from various sources, primarily TS Account Executives and customers. The forecast also includes expected sales of Conditional Firm Service. Long-term PTP sales are further adjusted to reflect anticipated PTP sales from customers whose existing IR or FPT agreements are expiring during the rate period and are expected to convert their transmission to OATT PTP service on the Network.

The long-term PTP sales forecast for the Southern Intertie (IS) is based on current and expected contract demands identified from OASIS, including additional long-term sales for OATT 2.2 renewals that have not been requested, but are expected to occur, and long-term sales that have been or are expected to be requested and offered. TR-10-E-BPA-01A, Table 14-1, lines 13, 14 and 15.

BPA TS does not anticipate offering Conditional Firm PTP service on the Interties or using an Open Season process on the Interties during the rate period.

Q. What effect does the LGIA Queue have on the TS sales forecast?

A. We forecast new, long-term PTP sales to be made before or during the rate period. As discussed above, based upon past experience, we assume that the service requested will equal 50% of the facility's nameplate capacity. *Id.* at Table 14-4, lines 24-33.

Q. How is the forecast of long-term transmission demand for the Montana Intertie (IM) developed?

A. The IM sales forecast includes one PTP service reservation for 16 megawatts on the Montana Intertie. *Id*. at Table 14-1, line 21. No other IM service is forecast.

Q. What are short-term sales and how are they forecast?

A. Short-term sales are point-to-point transmission service sales on the Network or Southern Intertie of less than one year in duration. They consist of monthly, weekly, and daily firm PTP and IS service as well as hourly firm and non-firm PTP and IS service. No short-term sales on the Montana Intertie are expected. We based the forecast of short-term sales of PTP and IS service on five years of historical sales data for the period May 2003 through April 2008. We do not include sales during this period from customers that are no longer actively purchasing short-term service (less than one and one half percent of total sales). *Id.* Table 14-1, line 11 and 17. Short-term sales represent less than 5% of the total transmission sales forecast.

Section 3: Transmission Revenue Forecast

Q. Please describe the revenue forecast process.

A. A summary of the revenue forecast by product, by year is presented in Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, at Tables 14-2 and 14-3. Revenues are forecast assuming current rates (*see id.* at Table 14-2) and proposed rates (*see id.* at table 14-3). The revenues from FPT, IR, PTP, NT, IS, IM, and Utility Delivery sales are calculated by applying the current and proposed rates to the billing factors of the sales forecast shown in Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, at Table 14-1. The proposed rates used are those set forth in the Settlement Agreement. *See* Bermejo *et al*, TR-10-E-BPA-06, Attachment 1.

Q. How were revenues for Ancillary and Control Area Services estimated?

A. The two required Ancillary Services, (1) Scheduling, System Control, and Dispatch Service and (2) Reactive Supply and Voltage Control from Generation Sources Service, use the same billing factor developed for transmission service. Thus, the sales forecasts generated for the Network, Southern Intertie, and Montana Intertie transmission sales were used to calculate the revenue forecasts for the two required Ancillary Services.

Forecasted sales of Operating Reserve services are an average of BPA's historical operating reserve requirement, net of self- and 3rd party-supplied reserves. BPA's Operating Reserve forecast will be based on 3% of load and 3% of net generation depending on the status of FERC approval of the proposed WECC standard BAL-002-WECC-1, which will replace the current standard.

Sales of Regulation and Frequency Response service use load forecasts developed by BPA forecast analysts. Wind Integration Within-Hour Balancing (WI) sales are based on the forecast of installed capacity of wind generation in the BPA Balancing Authority Area. No net revenue was assumed from Energy and Generation Imbalance Services.

Q. Have there been any changes in the methodology used to develop the revenue forecast for the 2010 transmission rate case?

A. No.

Q. Are all sources of revenue affected by the proposed rates?

A. No. Some revenues are recovered from sources other than the general transmission rates associated with the transmission services described above. We treat these revenues as revenue credits because in rate setting they would be used to credit costs prior to calculating the general rates. This includes revenue from certain rates such as the Townsend Garrison Transmission (TGT) and Southern Intertie Annual Cost (AC) rates, as well as revenue from various services that TS provides, such as Operation and Maintenance and Use of Facility (UFT) charges.

Q. *How are these revenue credits forecast?*

A. Revenue credits are forecast at actual FY 2008 levels with adjustments for known changes. These revenues amount to less than 7% of TS revenues. *See* Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, Table 14-1, lines 22-24.

Q. *Are there any other adjustments to the revenue sales forecasts?*

A. Yes

Q. *Describe these adjustments.*

A. Revenue forecasts for NT, Utility Delivery, and Regulation & Frequency Response that use load forecasts developed by BPA forecast analysts have the loads risk-adjusted to account for the expected impacts from uncertain economic conditions. Tools used to develop the risk-adjusted loads included a Monte Carlo simulation using spreadsheet models and the program, @Risk 5.0.

Q. *Will any changes be made to the revenue forecasts for the final rate proposal?*

A. No.

Q. *Does this conclude your testimony?*

A. Yes.

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TESTIMONY OF

RONALD J. HOMENICK, DANA M. JENSEN, ALEXANDER LENNOX,
and BYRNE E. LOVELL

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TESTIMONY OF

RONALD J. HOMENICK, DANA M. JENSEN, ALEXANDER LENNOX,

and BYRNE E. LOVELL

Witnesses for Bonneville Power Administration

SUBJECT: REVENUE REQUIREMENT STUDY

Section 1: Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Ronald J. Homenick and my qualifications are contained in TR-10-Q-BPA-08.

A. My name is Dana M. Jensen and my qualifications are contained in TR-10-Q-BPA-10.

A. My name is Alexander Lennox and my qualifications are contained in TR-10-Q-BPA-12.

A. My name is Byrne E. Lovell and my qualifications are contained in TR-10-Q-BPA-13.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to explain and support the development of the transmission revenue requirements for fiscal years 2010 and 2011 (Rate Period) and the accompanying risk analysis. This testimony also sponsors the Revenue Requirement Study, TR-10-E-BPA-01, and the Documentation for Revenue Requirement Study, TR-10-E-BPA-01A.

Q. How is your testimony organized?

A. Our testimony addresses assumptions used in the development of the transmission revenue requirements for the rate period and in the demonstration of cost recovery and repayment of the Federal investment. First, in Section 2, we discuss changes in general revenue requirement development, including the treatment of the regulatory asset for spacer dampers, and the use of cash reserves. In Section 3, we address the risk analysis. In Section 4, we address the demonstration that rates are no higher with the Debt Optimization (DO) program than without it, as called for in the Slice Settlement Agreement. In Section 5, we discuss the potential for adjustments and updates that may be made in the Final Rate Proposal.

Section 2: Revenue Requirements

Q. Have any changes been made to the way Bonneville Power Administration (BPA) determines the transmission revenue requirements?

A. No. We are using the same methodology as in the TR-08 rate proceeding. The basis for the revenue requirements is the total accrued expenses projected for each year of the rate period, displayed in an income statement. In addition, a cash flow statement is used to determine whether additional net revenues are required to cover the amortization payments scheduled by the repayment study and the cash required for risk mitigation. *See* Revenue Requirement Study, TR-10-E-BPA-01, Chapter 1. The categories by which the expenses are displayed are the only change. The line items in the operating expenses on the income statement have been reconstituted to reflect BPA's current standard financial report format. *Id*. at Chapter 4.1.1.

Q. How did BPA develop the forecast of program spending levels and capital investments used in the transmission revenue requirement?

A. BPA developed the program spending levels in the transmission revenue requirement during the Integrated Program Review (IPR). *Id*. at Chapter 2. In May and July 2008, BPA held IPR workshops with BPA customers and constituents to examine and take comments on BPA's proposed cost projections to be used in the concurrent generation and transmission rate cases. With regard to transmission, the IPR focused on the major transmission programs (e.g., operations, maintenance, planning) and capital investment planning and strategy. Federal and non-Federal debt service and debt management were discussed, though these forecasts are not determined in the IPR process.

On November 14, 2008, following a public comment period, BPA issued a close-out letter including a final report describing the forecast of program level expenses and capital investments to be used in the TR-10 Initial Proposal. *Id*. at Appendix A. In addition, BPA committed to conducting an abbreviated public process in the spring of 2009 to review the IPR forecasts and any updates that may be needed.

Q. Has BPA's forecast of program spending levels changed since the end of the IPR?

A. No. Although preliminary repayment study and depreciation forecast data reflected therein have been updated to incorporate the final conclusions of the IPR, the forecasts of program spending levels remain the same. However, after the conclusion of the IPR, the Administrator determined that a portion of the projected spending levels for operations and maintenance programs would be withheld from recovery by transmission rates in the 2010-1011 rate period and would be covered by other sources of funds.

Q. What are those other sources of funds?

A. Over the last several years, revenues from transmission rates have provided significant funds in excess of cash requirements, resulting in a buildup of cash reserves attributed to TS. The Administrator determined that, to allow BPA to maintain transmission rates at current levels, $50 million of cash reserves would be used to fund O&M expenses during the rate period without jeopardizing the business unit's Treasury Payment Probability (TPP). In this rate period, therefore, transmission rates will be based on the business unit's net expenses, after application of cash reserves.

Q. Are non-Federal payment obligations incorporated in the revenue requirement?

A. Yes. As in the TR-08 rate proceedings, the revenue requirement includes two financial obligations involving non-Federal funding sources that benefit the transmission system during the rate period and beyond. These are the obligation for annual payments associated with a third-party lease-purchase arrangement for a long-term capitalized transmission asset purchase (lease-purchase) and the reassignment to transmission of a portion of refinanced Energy Northwest (EN) non-Federal bond debt service obligations under BPA's Debt Optimization Program (Debt Service Reassignment). These obligations are treated in the same manner as in the TR-08 rate proceeding. The obligations incurred under the capital lease program and Debt Service Reassignment have been updated to reflect additional transactions that have occurred since the conclusion of the TR-08 rate proceeding.

Q. Have additional non-Federal payment obligations been incorporated in the revenue requirement?

A. Yes. The revenue requirement includes payment obligations associated with customer financed Network Upgrades under provisions of BPA's Open Access Transmission Tariff for large generator interconnections.

Q. Are there other assumptions about the use of transmission cash reserves that affect the determination of transmission revenue requirements?

A. Yes. As in the TR-08 rate proceedings, the transmission revenue requirements for the rate period reflect the assumption that BPA will use $15 million per year of transmission cash reserves instead of Treasury borrowing as a funding source for transmission capital.

Q. How is this proposed use of cash reserves for capital investments reflected in the revenue requirement for the rate period?

A. In the Statement of Cash Flows, the projected Treasury borrowing is $15 million less than the cash used for capital investments each year. The Revenue Requirement is generally unaffected because a draw-down of cash reserves is included as a source of funds in Cash from Current Operations to cover that difference. *Id.* at Table 4. However, as a direct result, the interest income calculation reflects this draw-down, showing the decrease in available cash reserves during the rate period. *See* Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, Chapter 4.

Q. Are there changes pertaining to the treatment of any transmission assets?

A. Yes. The treatment of the spacer damper regulatory asset that was created in FY 2006 will be modified during FY 2009 prior to the 2010-2011 rate period. At that time, most investment associated with this project for the accelerated replacement of spacer dampers that are causing accelerated deterioration of conductors will begin to be funded by the lease financing program rather than from Treasury borrowing and will no longer be considered regulatory assets. Existing spacer damper costs which were recorded as regulatory assets will continue as regulatory assets and continue to be amortized over 30 years from the date they were placed in service. As of FY 2009, only the cost of removal of the remaining spacer dampers that require replacement will be added to the regulatory asset. The lease-financed capital assets will be depreciated over 30 years. The depreciation and amortization forecasted for the rate period reflects this treatment

Section 3: Repayment Study

Q. Have there been any changes affecting the repayment study model?

A. No. BPA continues to use the same methodology and repayment study model.

Q. Does BPA anticipate any changes affecting the repayment study model?

A. It is possible that the computer model used to produce the repayment study will be replaced prior to the final proposal. The current model is customized to operate with the Munex debt management database system. Technical support from Munex for the repayment model is no longer available. As a result, there will be a change in the debt management database system from a Munex database system to the DBC database system produced by SS&C Technologies, Inc. Since the current repayment study model is customized to operate with Munex and is not compatible with DBC, BPA staff is developing a new computer model to function with the new database system.

Q. Will this change in model affect the methodology of the repayment study?

A. No. While the computer model will change, the repayment methodology used in the study will remain the same. As a result, the output of the new DBC-based model will be the same as the Munex-based model. This will be demonstrated in a workshop outside of this rate proceeding if it appears likely that the new model will be used for the final proposal.

Q. Will the new model introduce any improvements?

A. Yes. Since the completion of the 2007 power and 2008 transmission rate proceedings, BPA has entered into a new borrowing arrangement with the U.S. Treasury. The new arrangement introduces a wide array of options to call outstanding debt and allow early amortization. Unlike the current Munex model, the new model will fully replicate these options.

Section 4: Risk Analysis

Q. Has BPA made any changes to its risk analysis methodology?

A. Aside from minor adjustments as described in the underlying documents, BPA used the same method and spreadsheet model for the risk analysis used in the 2008 Final Transmission Proposal. *See* 2008 Final Transmission Proposal Revenue Requirement Study, TR-08-FS-BPA-01; 2008 Final Transmission Proposal Documentation for Revenue Requirement Study, TR-08-FS-BPA-01A, at Chapter 9; and Homenick, *et al.*, TR-08-E-BPA-05.

Q. Have you added any new risks to those modeled in the Transmission Risk Analysis Model (TRAM)?

A. Yes. The TRAM is now modeling uncertainty in the total installed capacity of wind generation in the BPA balancing area, as this affects the total revenue BPA receives. This risk is spread equally between TS and PS, as described in the risk section of the Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, at Chapter 9.9

Q. Have you removed any risks from the TRAM?

A. Yes. Interest rate uncertainty was modeled in the previous version of the TRAM, though its impact was minor. We were not able to adequately update the interest rate risk in time for the initial proposal, so we removed that risk. We are going to work on updating that data, and hope to reintroduce it to the final proposal TRAM.

Q. What are the results of the risk analysis for this rate period?

A. In this rate proposal, BPA has identified and quantified transmission risks and designed risk mitigation tools that achieve BPA's policy standard of at least a 95 percent U.S. Treasury payment probability. Simulations of BPA's financial reserves attributable to the transmission function have an expected value of $299 million at the end of FY 2011. These reserves meet BPA's TPP standard of 95 percent for a two-year period without the need to include any planned net revenue for risk in the revenue requirement. *See* Revenue Requirement Study, TR-10-E-BPA-01, Section 2.2.

Q. Do you anticipate making any changes to the risk analysis in the Final Proposal?

A. Yes. We will update the risk distributions if we are able to get more current information. We are hoping that we will be able to get enough information about current and projected interest rates that we can update the interest rate risk module and include it in the final proposal risk analysis. There is a possibility that TS will revise its determination of the amount of reserves needed to support wind generation, and this would affect the costs TS will need to pay PS for generation inputs. This would require revising the installed wind capacity risk module. TS and PS have not yet made an agreement on how TS payments to PS for generation inputs will vary if the total installed capacity of wind generation in the BPA balancing area differs from the amount forecast in the rate case, so there is a possibility that the actual agreement will be different from the assumption made in the initial proposal risk analysis. If this is the case, we will revise the risk analysis for the final proposal.

Q, Do you anticipate making any changes in the amount of reserves considered to be available for risk?

A. That is possible. There is only one Bonneville Fund. From that fund BPA makes all of its payments to the U.S. Treasury whether those payments are for repayment of debt associated with PS or TS. Since the TS TPP in the initial proposal is higher than 95% without the addition of any planned net revenues for risk (PNRR) to the TS rates, the level of reserves available for risk attributed to transmission is more than adequate to meet BPA's TPP standard without any additional contribution from TS rates. The Administrator may determine that some of the reserves available for risk attributed to transmission that are in excess of its TPP needs can be temporarily used to support the TPP for power rates, without requiring any increase in the FY 2010 – 2011 transmission rates. If he makes this determination, it would effectively encumber the reserves that PS would be relying on for TPP support.

Q. Is there any precedent for a determination of this kind?

A. Yes. In the WP-07 rate case, the Administrator determined that power rates could be based on the assumption that $55 million of reserves attributed to TS were available on a temporary basis to PS for FY 2007 only.

Q. Are there any important differences between that the circumstances of that determination and the one you are discussing now?

A. Yes. The earlier determination was made in FY 2006, the year prior to the beginning of PS' then next rate period, which was to be three years long. Transmission rates were already in place for FY 2006 and 2007, so the amount of reserves needed to meet the 95 percent TPP standard for the FY 2006-2007 rate period were already calculated. However, the amount of reserves needed for TPP after FY 2007 could not be known until TS set rates for the FY 2008-2009 rate period. Therefore, PS could not rely on any non-power reserves for the later two years of its rate period (FY 2008-2009). Now, in

FY 2009, both PS and TS are setting rates for FY 2010-2011. So the current determination can be made for PS' entire rate period. Another difference is that for PS rates to benefit the most from the temporary availability of reserves, the reserves have to be available for the entire rate period, both FY 2010 and 2011; that is, PS would not be able to plan on restoring the reserves before the end if its rate period.

Q. Could this have an adverse impact on transmission rates for the FY 2010-2011 rate period?

A. No. This approach only makes available reserves beyond those needed to meet the 95% TPP in the FY 2010-2011 rate period. TS will still be able to meet the TPP standard without adding PNRR to its revenue requirement. TS rates for FY 2010-2011 would not be affected.

Section 5: Slice/Debt Optimization Demonstration

Q. What is the Slice/Debt Optimization Demonstration?

A. BPA, Slice purchasers and Northwest Requirements Utilities (NRU) concluded litigation regarding the BPA's Slice Product, which is a particular power sale product, with a Memorandum of Understanding (Slice Settlement Agreement) that provided in part that BPA would make a demonstration showing that "rates of each of BPA's business lines [TS and PS] are no higher with the DOP [debt optimization program] than they would have been in the absence of the DOP." *See* Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, Chapter 13. The MOU further provided that "BPA will continue to so demonstrate achievement of this principle annually and in the next and subsequent general wholesale power and transmission rate proceedings so long as new DOP refinancings occur." *Id.*

Q. Please describe the DOP Demonstration provided in the revenue requirement study.

A. The DOP demonstration described the results of two repayment studies. The first study, consistent with the Initial Proposal, assumed that no additional DOP actions occurred after FY 2008. The second study included forecasted DOP actions beyond FY 2008. The results showed that over a twenty-year horizon the total capital costs (Federal amortization, interest, and third-party debt service) were on average no different in the two studies, which means that rates would be no higher with DOP than without such actions, including rates for this rate period. *Id.*

Q. Please explain the DOP-related costs that are included in the transmission rates established in this proceeding.

A. The revenue requirement income statement includes "Debt Service Reassignment Interest" which includes the interest expense associated with DOP actions. Revenue Requirement Study, TR-10-E-BPA-01A, at Table 3. The statement of cash flows includes "Debt Service Reassignment Principal" which represents non-Federal principal that is repaid. *Id.* at Table 4. The development of these costs, which incorporate all DSR transactions made to date, are explained and detailed in Documentation for Revenue Requirement Study, TR-10-E-BPA-01A.

Section 6: Possible Changes for Final Proposal

Q. What additional changes could affect the Revenue Requirement Study in the Final Rate Proposal?

A. As noted earlier, BPA committed to an abbreviated cost review process during, but separate from, this rate proceeding. The final proposal will incorporate any changes to program spending level forecasts that may come from that process. In addition, the repayment study will incorporate updates for actual debt management actions including DOP actions that may occur prior to the final proposal.

Q. Does that conclude your testimony?

A. Yes.

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TESTIMONY OF

SARAH K. BERMEJO, EDISON G. ELIZEH, MARK A. JACKSON and
TERRIN L. PEARSON

Witnesses for Bonneville Power Administration

SUBJECT: OVERVIEW OF PARTIAL SETTLEMENT

TESTIMONY OF

SARAH K. BERMEJO, EDISON G. ELIZEH, MARK A. JACKSON,

AND TERRIN L. PEARSON

Witnesses for Bonneville Power Administration Transmission Services

SUBJECT: OVERVIEW OF PARTIAL SETTLEMENT

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Sarah K. Bermejo and my qualifications are stated in TR-10-Q-BPA-01.

A. My name is Edison G. Elizeh and my qualifications are stated in TR-10-Q-BPA- 05.

A. My name is Mark A. Jackson and my qualifications are stated in TR-10-Q-BPA-09.

A. My name is Terrin L. Pearson and my qualifications are stated in TR-10-Q-BPA-16.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to provide an overview of that portion of the 2010 Initial Rate Proposal that is based on the Partial Settlement Agreement for the 2010 transmission rate case. This testimony also sponsors the 2010 transmission rate schedules and the rate schedules for the two ancillary services covered by the Partial Settlement Agreement: Scheduling, System Control, and Dispatch Service and Reactive Supply and Voltage Control from Generation Sources Service.

Q. How is your testimony organized?

A. The testimony is organized in four sections. Section 1 is this introduction. Section 2 provides an overview of the Partial Settlement Agreement and the proposed rates covered by the agreement. Section 3 reviews the proposed revisions to the Failure to Comply Penalty Charge, the Unauthorized Increase Charge, the Reactive Supply and Voltage Control from Generation Sources Service rate schedule, and the Network Integration rate schedule. Section 4 addresses the equitable allocation standard in relation to the rate proposal.

Section 2: Partial Settlement Agreement and Initial Rate Proposal

Q. Please describe how Transmission Services (TS) and interested parties developed the Partial Settlement Agreement for the 2010 transmission rate case.

A. In preparation for the 2010 transmission rate case, during 2008 TS held a number of public rate case workshops with transmission customers and interested parties. At the November 21, 2008, workshop TS distributed a list of issues for possible settlement. At the December 5, 2008, workshop TS proposed rate levels for the 2010-2011 rate period as part of a partial settlement of the transmission rate case. TS then posted a draft partial settlement agreement, which the parties discussed at workshops on December 12 and December 19.

The resulting final Partial Settlement Agreement includes rates for all transmission rate schedules and for the ancillary services Scheduling, System Control, and Dispatch Service and Reactive Supply and Voltage Control from Generation Sources Service, and changes to several other rate schedules (discussed below). The Partial Settlement Agreement was sent to customers and interested parties for signature. TS signed the Partial Settlement Agreement after receiving signed agreements from most customers and interested parties. TS's Initial Proposal reflects the terms of the Partial Settlement Agreement. The Partial Settlement Agreement is attached to this testimony as Attachment 1. A list of entities that signed the Partial Settlement Agreement is attached as Attachment 2.

Q. Please provide an overview of the portion of the Initial Proposal that is based on the Partial Settlement Agreement.

A. TS proposes to leave rates for all transmission services covered by the Partial Settlement Agreement unchanged from current rate levels. TS has determined that current rates are sufficient for TS to recover its costs during the rate period. TS is proposing changes in the rates for the Failure to Comply Penalty Charge and the Unauthorized Increase Charge. In addition, TS agreed that it will not assess the revised Failure to Comply Penalty Charge until it has adopted a business practice to implement the revised charge.

Q. What other agreements are reflected in the portion of the Initial Proposal that is based on the Partial Settlement Agreement?

A. TS agreed to hold discussions during 2009 with all interested parties regarding segmentation, cost of service methodology, and rate design for future transmission rates, and to establish protocols for how it will respond to issues raised during the discussions.

Section 3: Changes to Rate Schedules

Q. Please describe the change to the rate under the Failure to Comply Penalty Charge.

A. The existing rate for a party's failure to comply with a TS order is the highest of 100 mills per kilowatthour; the costs incurred by TS to manage the reliability of the transmission system because of the failure to comply; or an hourly market index price plus ten percent. The proposed rate is a flat 1000 mills per kilowatthour plus two categories of costs: the cost of alternate measures TS takes to manage the reliability of the system because of the failure to comply; and monetary penalties imposed on BPA by a Regional Reliability Organization, the Electric Reliability Organization, or FERC for a violation of a Reliability Standard, if the violation was caused by the party's failure to comply.

Q. What is the reason for the proposed change to the rate under the Failure to Comply Penalty Charge?

A. TS is proposing this change to accomplish two goals. First, the proposed rate of 1000 mills per kilowatthour is high enough to ensure that it is never in a party's economic interest to deliberately fail to comply with a TS order. Second, the language ensures that TS is made whole in the event it incurs expenses or is assessed a monetary penalty because of the party's failure to comply.

Q. Please describe the change to the Failure to Comply billing factor.

A. The existing billing factor is the kilowatthours that were not curtailed or redispatched in response to a TS order. TS has added language to the billing factor to include kilowatthours that are not "shed, changed, or limited" in response to a TS order. TS has also added language to make clear that customers have ten minutes to comply with an order. The additions ensure that the penalty charge covers all appropriate situations, and that customers have sufficient time to comply with orders.

Q. Has TS proposed any other changes to the Failure to Comply Charge?

A. Yes. TS has proposed clarifying language to the rate schedule to include dispatch orders among the orders that can lead to a failure to comply penalty and to clarify that orders TS issues to change or limit generation levels will be issued in accordance with Good Utility Practice as defined in BPA's open access transmission tariff.

Q. Please describe the changes to the Unauthorized Increase Charge (UIC).

A. TS has proposed multiple changes to the UIC. The current rate for PTP customers is two times the applicable transmission rate. TS has proposed changing this rate to the lower of (a) 100 mills per kilowatthour plus the price cap established by FERC for spot market sales of energy in the WECC, or (b) 1000 mills per kilowatthour. If FERC eliminates the price cap, the rate schedule provides for a UIC of 500 mills per kilowatthour. The UIC rate for NT service is unchanged.

Q. What is the reason for the change to the UIC?

A. The reason for the change in the UIC is similar to the reason TS has proposed a change in the failure to comply penalty charge: to ensure that transmission customers never have an incentive to deliberately exceed their capacity reservations. Depending on the price of energy, a rate of two times the applicable transmission rate could be less than the profit a party could make by exceeding its transmission capacity. With a rate significantly above the price cap, this scenario is extremely unlikely.

Q. What other changes is TS proposing in the UIC rate schedule?

A. TS is proposing changes to the language describing the billing factor for PTP customers and to the waiver provisions. Under the existing rate schedule, TS adds the amounts that exceed capacity reservations for all PODs and for all PORs. The billing factor is the greater of the highest one-hour POD sum or highest one-hour POR sum. The proposed billing factor is the greater of the total of the POD hourly amounts for the month or the total of the POR hourly amounts for the month. Under the proposal, customers will be charged for each hour they exceed their reservation rather than only for the highest hour. The change removes the "free ride" that customers receive with the existing billing factor − that is, once they have exceeded their capacity reservations for the month they can exceed it again without penalty.

The billing factor for NT customers is unchanged.

Q. Please describe the changes to the waiver provisions of the UIC.

A. TS has added language to the UIC rate schedule to make clear that, if TS reduces or waives the UIC, the customer still must pay for the underlying transmission service for the excess demand. If TS reduces or waives the UIC for one or more hours in the same calendar day, the proposed rate for the excess transmission demand is the daily rate. If TS waives or reduces the UIC on multiple days in the same calendar week, the proposed rate for the excess demand is the rate for seven days of service. If TS reduces or waives the UIC in multiple weeks during the same month, the proposed rate for the excess demand is the rate under the applicable rate schedule for the number of days in the month.

This clarification ensures that, even if TS waives or reduces the UIC, it is compensated for the service provided. The rate structure also discourages repeated usage of excess transmission demand.

Q. What is the proposed billing factor when TS waives or reduces the UIC?

A. For PTP customers, the proposed billing factor when TS waives the UIC is the transmission customer's highest excess transmission demand for which TS waives the UIC. If TS reduces the UIC, the billing factor is the customer's highest excess transmission demand that, as a result of the reduction, is not subject to the UIC. This billing factor ensures that TS is compensated for the actual transmission used.

For NT customers, the billing factor is the NT rate, except that the billing factor for the base charge shall not be reduced for that portion of the transmission demand for which TS waives or reduces the UIC.

Q. Is TS proposing any other changes to the UIC charge?

A. Yes. TS has clarified the criteria under which it will grant a waiver of the UIC. The proposed language provides that TS may grant a waiver if the event that resulted in the UIC was inadvertent or the result of an equipment failure or outage that the transmission customer could not have reasonably foreseen. TS has also proposed deleting the existing final paragraph under "UIC Relief."

Q. Please describe the final paragraph and explain why TS has proposed deleting it.

A. The final paragraph under "UIC Relief" provides that, if TS fails to notify a customer that the customer is subject to a UIC during a month and, because of the failure to notify, the customer is also subject to a UIC the following month, TS will waive all UICs except for the highest in the series. TS included this paragraph in the existing rate schedule because TS was often untimely in notifying customers that they were subject to a UIC. Because TS now notifies customers promptly, the paragraph is unnecessary.

In addition, TS has added a sentence to the opening paragraph of the UIC rate schedule providing that TS will notify customers that they are subject to a UIC once TS has verified the amount of the UIC. Thus, in place of the paragraph providing for waiver for failure to notify, TS has undertaken an affirmative commitment to notify customers of UICs.

Q. Please describe the changes to the Reactive Supply and Voltage Control from Generation Sources Service (GSR) rate schedule.

A. The GSR rate is a formula rate that is based in part on the average of forecasted GSR billing determinants for the two-year rate period. Transmission Services has updated the rate schedule so that the rate is based on forecasts for the 2010 and 2011 fiscal years rather than the 2008 and 2009 fiscal years, to ensure that the rate is based on current information. Transmission Services also replaced all references in the rate schedule to "October 1, 2007"—the beginning of the existing rate period—with "October 1, 2009," the beginning of the new rate period.

Q. Please describe the change to the Network Integration (NT) rate schedule.

A. In October 2008 BPA filed a revised open access transmission tariff with FERC, which included conditional firm service for network integration customers. The rate for conditional firm service is the same as the rate for network integration service. Therefore, Transmission Services has amended the availability section of the NT rate schedule so that the rate schedule applies to NT customers taking either network transmission service or conditional firm service. Because BPA had decided much earlier to adopt conditional firm service for point-to-point customers, Transmission Services amended the PTP rate schedule in the last rate case.

Section 4: Equitable Allocation

Q. Do the proposed transmission and ancillary services rates represent an equitable allocation of costs between Federal and non-Federal power?

A. Yes. Transmission Services is not presenting segmentation and cost allocation studies to support the proposed rates; the rates are a product of the Partial Settlement Agreement. Nevertheless, equitable allocation is demonstrated in two important ways.

First, equitable allocation between Federal and non-Federal power is achieved through adherence to the principle of comparability. Before 1996, when most transmission for Federal power was provided for in bundled sales contracts, an allocation of costs in the rate case was needed to demonstrate equitable allocation of transmission costs between Federal and non-Federal power. Under BPA's open access transmission tariff, however, purchasers of transmission for

Federal power, including both BPA's Power Services business line and Power Services' customers, receive the same service and pay the same rates as purchasers of transmission for non-Federal power. BPA draws no distinction between Federal and non-Federal power using the transmission system. An equitable allocation of transmission costs between Federal and non-Federal power is achieved through application of the same rates to the two classes of service. A separate rate case cost allocation is unnecessary.

Second, equitable allocation is demonstrated by the breadth of the settlement and the diversity among the settling parties. The settling parties include Power Services and full requirements customers of Power Services; large partial requirements customers that both buy Federal power and wheel large amounts of non-Federal power; large wheeling customers, such as several investor-owned utilities, which purchase little Federal power; and several resource developers. Transmission Services would not have been able to obtain the agreement of such a large and diverse group of customers unless the proposed allocation of costs was equitable.

Q. *Does this conclude your testimony?*

A. Yes.

PARTIAL SETTLEMENT AGREEMENT
Bonneville Power Administration 2010 Transmission Rate Case

The undersigned signatories to this Partial Settlement Agreement hereby agree to the following:

1. In the Bonneville Power Administration (BPA) 2010 Transmission Rate Case (Rate Case), BPA Transmission Services (TS) will submit a proposal (Settlement Proposal) to establish rates for fiscal years 2010-2011 (Rate Period) for all transmission services as shown in Attachment 1. This Settlement Proposal will include changes to the Failure to Comply Penalty Charge, the Unauthorized Increase Charge, the Reactive Supply and Voltage Control from Generation Sources Service rate schedule, the Scheduling, System Control, and Dispatch Service rate schedule, and the availability section of the Network Integration Rate, all shown in redline on Attachment 2. The Settlement Proposal will include no other changes to existing rate schedules for the services listed above or to the general rate schedule provisions as they relate to the services listed above; except that TS has the right to propose a formula or formulas for all incremental cost rates and to propose the structure and elements of a public process for determining and allocating costs when BPA offers transmission service at an incremental cost rate. The incremental cost rate is not part of the Settlement Proposal, and the parties have the right to challenge any aspect of the formulas and public process that TS proposes.

2. The ancillary services Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserve − Spinning Reserve Service, Operating Reserve − Supplemental Reserve Service, and Generation Imbalance Service, and all control area services, are not included in this settlement. All issues concerning these services, including the amount and pricing of the reserve capacity needed for such services, will be litigated in the power rate case, docket number WP-10. All issues concerning rate design and the rate schedules for these services will be litigated in this transmission rate case, docket number TR-10. BPA reserves the right to propose changes to the rates, rate schedules, and associated general rate schedule provisions for these services, and the signatories to this settlement preserve the right to litigate all issues concerning these services.

3. During 2009, BPA will hold discussions with all interested parties regarding segmentation, cost of service methodology, and rate design for future transmission rates. Such discussions will include, but not be limited to, ratemaking to recover the costs of the Utility Delivery segment, and the costs of transmission facilities that comprised the former Northern Intertie transmission segment. Parties may raise other topics for BPA's consideration that are relevant to the design of transmission rates. In the discussions, BPA will establish protocols for how it will respond to issues raised.

4. BPA will hold a public process to develop a business practice for implementing the revised Failure to Comply Penalty Charge, and BPA will not assess such charge before it has adopted a final business practice.

5. The signatories agree not to contest any aspect of the Settlement Proposal, or, with respect to the rates included in the Settlement Proposal and established for the Rate Period, any of the elements thereof, the methodologies and principles used to derive such rates, or any aspect of the rate schedules or general rate schedule provisions, or any other issue that is included in the Settlement Proposal. The signatories further agree to waive their rights to cross-examination and discovery with respect thereto, except in response to issues raised by any party in such proceeding that is not a signatory to this Partial Settlement Agreement. If, however, TS does not submit a Settlement Proposal consistent with the terms of this Partial Settlement Agreement, the signatories may contest any aspect of the Settlement Proposal.

6. The signatories intend that revised Attachment M (Attachment 3 to this Partial Settlement Agreement) will replace the existing Attachment M in BPA's Open Access Transmission Tariff (Tariff). BPA will submit revised Attachment M to FERC for approval as an amendment to BPA's Tariff. The signatories agree not to protest such proposed amendment at FERC or in any other forum. Nothing in this Partial Settlement Agreement limits a signatory's right to argue in an appropriate forum that, when making curtailments, BPA has not curtailed on a non-discriminatory basis the schedules(s) that effectively relieve the constraint.

7. The signatories will move the Hearing Officer to specify a date, within a reasonable time of the prehearing conference in the Rate Case, by which any party to the Rate Case that has not executed this Partial Settlement Agreement must object to the settlement proposed in this Partial Settlement Agreement and identify each issue included in the Settlement Proposal that such Rate Case party chooses to preserve for hearing. If no Rate Case party objects to the Settlement Proposal and preserves issues for hearing, TS shall propose to the Administrator that he adopts the Settlement Proposal in its entirety and BPA shall submit the revised Attachment M to FERC as a proposed amendment to BPA's Tariff. In the event that any Rate Case party does so object to the Settlement Proposal, TS may, but shall not be required to, revise the Settlement Proposal as it believes appropriate and BPA may, but shall not be required to, revise Attachment M as it believes appropriate, either after such Rate Case party states its objection or after parties file their direct testimony. If TS decides to revise the Settlement Proposal, or if BPA decides to revise Attachment M, the parties will meet promptly to discuss a new procedural schedule that they will propose to the Hearing Officer, allowing TS or BPA, as the case may be, a reasonable time in which to present a revised proposal and the parties a reasonable time to respond to such revised proposal. In that event, the signatories may contest any aspect of the revised proposal.

8. Nothing in this Partial Settlement Agreement is intended in any way to alter the Administrator's authority and responsibility to periodically review and revise the Administrator's transmission rates or the signatories' rights to challenge such revisions.

9. If the Administrator establishes transmission rates in accordance with the Settlement

Proposal and submits such rates to FERC for confirmation and approval under the applicable standards of the Northwest Power Act or as a reciprocity filing, the signatories agree not to challenge such confirmation and approval of such rates or any element thereof, including the methodologies and principles used to establish such rates, or support or join any such challenge, and agree not to challenge such rates or any element thereof, including the methodologies and principles used to establish such rates, in any judicial forum.

10. The signatories agree that they will not assert in any forum that anything in this Partial Settlement Agreement or any action with regard to this Partial Settlement Agreement taken or not taken by any signatory, the Hearing Officer, the Administrator, FERC, or a court, creates or implies any procedural or substantive precedent or creates or implies agreement to any underlying principle or methodology, or creates any precedent under any contract between BPA and any signatory.

11. By executing this Partial Settlement Agreement, no signatory waives any right to pursue BPA Tariff dispute resolution procedures consistent with BPA's Tariff (including without limitation any complaint concerning implementation of BPA's Tariff) or any claim that a particular charge, methodology, practice or rate schedule has been improperly applied.

12. Nothing in this Partial Settlement Agreement amends any contract or modifies rights or obligations or limits the remedies available thereunder.

This Partial Settlement Agreement may be executed in counterparts.

____________________________for

___________________________ Date ___________
Party

Attachment 1
Summary of Rate Levels

	Units	Proposed 2010 Rates	
		FPT-10.1	FPT-10.3
FPT-10.1 and FPT-10.3			
M-G Distance.....................	$/kW-mi-yr	0.0587	0.0587
M-G Miscellaneous Facilities.....	$/kW-yr	3.35	3.35
M-G Terminal.....................	$/kW-yr	0.68	0.68
M-G Interconnection Terminal.....	$/kW-yr	0.61	0.61
S-S Transformation...............	$/kW-yr	6.31	6.31
S-S Interconnection Terminal.....	$/kW-yr	1.73	1.73
S-S Intermediate Terminal........	$/kW-yr	2.44	2.44
S-S Distance.....................	$/kW-mi-yr	0.5772	0.5772
Overall FPT Rate...............	$/kW-yr	15.93	15.93
Overall FPT Rate...............	$/kW-mo	1.327	1.327
IR-10			
Demand...........................	$/kW-mo	1.498	
NT-10			
Base Rate ($/kW-mo)..............	$/kW-mo	1.298	
Load Shaping ($/kW-mo)...........	$/kW-mo	0.367	
Base plus Load Shaping.........	$/kW-mo	1.665	
PTP-10			
Demand...........................	$/kW-mo	1.298	
Daily Block 1 (day 1 thru 5).....	$/kW-day	0.060	
Daily Block 2 (day 6 and beyond).	$/kW-day	0.046	
Hourly...........................	mills/kWh	3.74	
Utility Delivery			
Demand...........................	$/kW-mo	1.119	
IS-10			
Demand...........................	$/kW-mo	1.293	
Daily Block 1 (day 1 thru 5).....	$/kW-day	0.060	
Daily Block 2 (day 6 and beyond).	$/kW-day	0.045	
Hourly...........................	mills/kWh	3.72	
IM-10			
Demand...........................	$/kW-mo	1.312	
Daily Block 1 (day 1 thru 5).....	$/kW-day	0.061	
Daily Block 2 (day 6 and beyond).	$/kW-day	0.043	
Hourly...........................	mills/kWh	3.78	
Intertie East			
IE-10............................	mills/kWh	1.13	

Attachment 1
Summary of Rate Levels

	Units	Proposed 2010 Rates
Power Factor Penalty Charge		
Demand -- Lagging................	$/kVAr-mo	0.28
Demand -- Leading................	$/kVAr-mo	0.24
Scheduling Control and Dispatch ('10)		
Demand...........................	$/kW-mo	0.203
Daily Block 1 (day 1 thru 5).....	$/kW-day	0.010
Daily Block 2 (day 6 and beyond).	$/kW-day	0.006
Hourly...........................	mills/kWh	0.59
Generation Supplied Reactive ('10)		
Demand...........................	$/kW-mo	0.000
Daily Block 1 (day 1 thru 5).....	$/kW-day	0.000
Daily Block 2 (day 6 and beyond).	$/kW-day	0.000
Hourly...........................	mills/kWh	0.00

Attachment 2
Scheduling, System Control and Dispatch Service

SECTION II. ANCILLARY SERVICE RATES

A. SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

The rates below apply to Transmission Customers taking Scheduling, System Control and Dispatch Service from BPA-TS. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, on the Southern Intertie, and on the Montana Intertie are each charged separately for Scheduling, System Control and Dispatch Service.

1. RATES

a. Long-Term Firm PTP Transmission Service and NT Service

The rate shall not exceed $0.203 per kilowatt per month.

b. Short-Term Firm and Non-Firm PTP Transmission Service

For each reservation, the rates shall not exceed:

(1) Monthly, Weekly, and Daily Firm and Non-Firm Service

(a) Days 1 through 5 $0.010 per kilowatt per day

(b) Day 6 and beyond $0.006 per kilowatt per day

(2) Hourly Firm and Non-Firm Service

The rate shall not exceed 0.59 mills per kilowatthour.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in section 1.a., 1.b.(1), and for the Hourly Firm PTP Transmission Service rate specified in 1.b.(2) shall be the Reserved Capacity, which is the greater of:

(1) the sum of the capacity reservations at the Point(s) of Receipt, or

(2) the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service shall not be adjusted for any Short-Distance Discounts or for any modifications on a non-firm basis in determining the Scheduling, System Control and Dispatch Service Billing Factor.

The Billing Factor for the rate specified in section 1.b.(2) for Hourly Non-Firm Service shall be the ~~scheduled kilowatthours. Upon 60 day's notice by BPA-TS, the Billing Factor for the rate specified in section 1.b.(2) for Hourly Non-Firm Service shall become the~~ Reserved Capacity and~~.~~

~~When Reserved Capacity becomes the Billing Factor for Hourly Non-Firm Service,~~ the following shall apply:

i. If the need for Curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:

a. If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

b. If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.

ii. If the need for Curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

These Billing Factors apply to all PTP transmission service under the Open Access Transmission Tariff regardless of whether the

Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT Base Charge Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-~~08~~10).

c. Adjustment for Customers Subject to the Unauthorized Increase Charge (UIC)

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rate schedules) that are subject to a UIC in a billing month, the Billing Factor for the billing month shall be the Billing Factor calculated above plus the UIC Billing Factor calculated under section II.G.2.a. of the GRSPs.

For Transmission Customers taking Network Integration Transmission Service that are subject to a UIC in a billing month, the Billing Factor for the billing month shall be the Billing Factor calculated above plus the UIC Billing Factor calculated under section II.G.2.b. of the GRSPs.

Attachment 2
Failure to Comply Penalty Charge

B. FAILURE ~~TO~~ TO COMPLY PENALTY CHARGE AND ~~A~~ASSESSMENT OF O~~O~~THER C~~C~~OSTS R~~R~~ESULTING F~~F~~ROM THE F~~F~~AILURE TO C~~C~~OMPLY

1. RATE FOR FAILURE TO COMPLY PENALTY CHARGE

If a party fails to comply with the BPA-TS's dispatch, curtailment, redispatch, or load shedding orders, the party will be assessed the Failure to Comply Penalty Charge. The Failure to Comply Penalty Charge shall be 1000 mills per kilowatthour.

Parties who are unable to comply with a dispatch, curtailment, load shedding, or redispatch order due to a force majeure on their system will not be subject to ~~this penalty~~ the Failure to Comply Penalty Charge provided that they immediately notify the BPA-TS of the situation upon occurrence of the force majeure.

~~**1. RATE**~~

~~The rate shall be the highest of:~~

~~a. 100 mills per kilowatthour;~~

~~b. any costs incurred by the BPA-TS in order to manage the reliability of the FCRTS due to the failure to comply;~~

~~c. an hourly market price index plus 10%.~~

~~The hourly market price index will be the larger of the California ISO Real-Time Hourly Average Energy Price or the Dow Jones Mid-Columbia Firm Index Price for the hour(s) when the failure to comply occurred.~~

2. BILLING FACTORS

The Billing Factor for the Failure to Comply Penalty Charge shall be the kilowatthours that were not curtailed~~or~~, redispatched, shed, changed, or limited within ten minutes after issuance of the order in any of the following situations:

a. Failure to shed load when directed to do so by BPA-TS in accordance with the Load Shedding provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to shed load pursuant to such orders within the time period specified by the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) criteria.

b. Failure of a generator in the BPA Control Area or which directly interconnects to the FCRTS to change or limit generation levels when directed to do so by the BPA-TS in accordance with Good Utility Practice as defined in the OATT. This includes failure to change generation levels pursuant to such orders within the time period specified by NERC, WECC, or NWPP criteria.

c. Failure to curtail or redispatch a reservation or schedule or failure to curtail or redispatch actual transmission use of the Contract or Service Agreement when directed to do so by the BPA-TS in accordance with the curtailment or redispatch provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to curtail or redispatch pursuant to such scheduling protocols or orders within the time period specified by NERC, WECC, or NWPP criteria.

3. ASSESSMENT OF OTHER COSTS RESULTING FROM THE FAILURE TO COMPLY

In addition to the Failure to Comply Penalty Charge, the party ~~may~~will be assessed the costs of alternate measures taken by BPA-TS in order to manage the reliability of the FCRTS due to the failure to comply.

The party ~~may~~ will also be assessed monetary penalties imposed on BPA by a Regional Reliability Organization, Electric Reliability Organization, or FERC, for a violation of a Reliability Standard authorized under Section 215 of the Energy Policy Act of 2005, to the extent that the violation was caused by the party's failure to comply.

Attachment 2
Unauthorized Increase Charge

G. UNAUTHORIZED INCREASE CHARGE (UIC)

Transmission Customers taking Point-to-Point Transmission Service under the PTP, IS, and IM Rate Schedules shall be assessed the UIC when they exceed their capacity reservations at any Point of Receipt (POR) or Point of Delivery (POD). Transmission Customers taking Network Integration Transmission Service under the NT Rate Schedule shall be assessed the UIC if their Actual Customer-Served Load (CSL) is less than their Declared CSL. BPA-TS will notify a Transmission Customer that is subject to a UIC once BPA-TS has verified the UIC amount.

1. RATE

a. Point-To-Point Transmission Service (PTP, IS, and IM Rate Schedules)

Lower of (i) 100 mills per kilowatthour plus the price cap established by FERC for spot market sales of energy in the WECC, or (ii) 1000 mills per kilowatthour.~~.~~ If FERC eliminates the price cap, the rate will be 500 mills per kilowatthour.

~~**(1)Long-Term Transmission Service**~~

~~The UIC rate shall be two (2) times the PTP, IS, or IM rate per kilowatt per month for Long-Term Firm PTP Transmission Service as specified in section II.A. of the applicable rate schedule.~~

~~**(2)Monthly, Weekly, and Daily Transmission Service**~~

~~The UIC rate shall be two (2) times the rate per kilowatt for transmission service, calculated by applying the rates per kilowatt per day specified in section II.B.1 of the applicable rate schedule to the total number of days of the transmission reservation.~~
~~The UIC rate shall not exceed two (2) times the PTP, IS, or IM rate per kilowatt per month for Long-Term Firm Transmission Service.~~

~~**(3)Hourly Transmission Service**~~

~~The UIC rate shall be two (2) times the rate per kilowatt for transmission service, calculated by applying the rate per kilowatthour specified in section II.B.2 of the applicable~~

~~rate schedule to the total number of hours of the transmission reservation.~~

b. Network Integration Transmission Service (NT Rate Schedule)

$2.596 per kilowatt per month

2. BILLING FACTORS

a. Point-To-Point Transmission Service (PTP, IS, and IM Rate Schedules

For each hour of the monthly billing period, BPA-TS shall determine the amount by which the Transmission Customer exceeds its capacity reservation at each POD and POR, to the extent practicable. BPA-TS shall use hourly measurements based on a 10-minute moving average to calculate actual demands at PODs associated with loads that are one-way dynamically scheduled and at PORs associated with resources that are one-way dynamically scheduled. To calculate actual demands at PODs and PORs that are associated with two-way dynamic schedules, BPATS shall use instantaneous peak demands for each hour. Actual demands at all other PODs and PORs will be based on 60-minute integrated demands or transmission schedules.

For each hour, BPA-TS will sum these amounts that exceed capacity reservations: 1) for all PODs, and 2) for all PORs. The Billing Factor for the monthly billing period shall be the greater of the total of the ~~highest one-hour~~ POD ~~sum~~ hourly amounts or ~~highest one-hour~~the total of the POR ~~sum~~ hourly amounts.

b. Network Integration Transmission Service (NT Rate Schedule)

In each billing month on the hour of the Monthly Transmission Peak Load, the Billing Factor shall equal the Declared CSL minus the Actual CSL.

3. UIC RELIEF

a. Criteria for Waiving or Reducing the UIC

Under appropriate circumstances, BPA-TS may waive or reduce the UIC to a Transmission Customer on a non-discriminatory basis. A Transmission Customer seeking a reduction or waiver must demonstrate good cause for relief, including ~~a~~ demonstrati~~on~~ng that the event that resulted in the UIC:

~~1. The event which resulted in the UIC~~

~~(a) was the result of an equipment failure or outage that could not reasonably have been foreseen by the customer; and~~

~~a.did not result in harm to BPA-TS's transmission system or transmission services, or to any other Transmission Customer; or~~

~~2. The event which resulted in the UIC~~

~~i.~~ (1) ~~w~~was inadvertent or was the result of an equipment failure or outage that the Transmission Customer could not have reasonably foreseen;

~~ii.~~ (2) ~~c~~could not have been avoided by the exercise of reasonable care;

and

~~iii.~~ (3) ~~d~~did not result in harm to BPA-TS's transmission system or transmission services, or to any other Transmission Customer.~~; and~~

~~iv.was not part of a recurring pattern of conduct by the Transmission Customer.~~

If a waiver or reduction is granted to a Transmission Customer, notice of such waiver or reduction will be posted on the BPA-TS's OASIS.

~~If the Transmission Customer is subject to a UIC in a month, but has not received notice from the BPA-TS of such UIC by billing or otherwise, and the Transmission Customer is also subject to UIC(s) in the following month(s) due to the lack of notice, then the BPA-TS may bill the Transmission Customer for the highest UIC in the series. The UIC for all other months (including the first month(s) if it does not have the highest UIC) in such a series will be waived.~~

b. Transmission Rate if BPA-TS Waives or Reduces the UIC

If BPA-TS waives or reduces the UIC, the Transmission Customer remains subject to the applicable rates, including Ancillary Services rates, for the Transmission Customer's transmission demand. The following rates shall apply to transmission demand that exceeds the capacity reservations of a Transmission Customer taking service under the PTP, IS or IM Rate Schedules if BPA-TS waives or reduces the UIC:

(1) If BPA-TS waives or reduces the UIC for excess transmission demand in one or more hours in the same calendar day, the rate for

one day of service under section II.B.1 of the applicable PTP, IS or IM rate schedule shall apply.

(2) If BPA-TS waives or reduces the UIC for excess transmission demand on multiple calendar days in the same calendar week, the rate for seven days of service under section II.B.1 of the applicable PTP, IS or IM rate schedule shall apply.

(3) If BPA-TS waives or reduces the UIC for excess transmission demand in one or more hours in multiple calendar weeks in the same calendar month, the rate for the number of days in the month of service under section II.B.1 of the applicable PTP, IS or IM rate schedule shall apply.

For a Transmission Customer taking Point-to-Point Transmission Service under the PTP, IS or IM Rate Schedules, the Billing Factor for rates in this section 3.b shall be: (a) the Transmission Customer's highest excess transmission demand for which BPA-TS waives the UIC; or (b) if BPA-TS reduces the UIC, the Transmission Customer's highest excess transmission demand that is not subject to the UIC as a result of the reduction.

If BPA-TS waives or reduces the UIC for a Transmission Customer taking Network Integration Service, the rate in section II of the NT Rate Schedule shall apply. The Billing Factor shall be as specified in section III of the NT Rate Schedule, except that the Billing Factor for the Base Charge under section III.A shall not be reduced for that portion of the transmission demand for which BPA-TS waives or reduces the UIC.

Attachment 2
Reactive Supply and Voltage Control from Generation Sources Service

SECTION II. ANCILLARY SERVICE RATES

B. REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

The rates below apply to Transmission Customers taking Reactive Supply and Voltage Control from Generation Sources (GSR) Service from BPA-TS. These rates apply to both firm and non-firm transmission service. Transmission arrangements on the Network, on the Southern Intertie, and on the Montana Intertie are each charged separately for Reactive Supply and Voltage Control from Generation Sources Service.

1. RATES

The rates for GSR Service will be set on a quarterly basis, beginning October 2009~~7~~, according to the formulas below. Rates for Long-Term PTP and NT Service and for Short-Term Monthly, Weekly and Daily Service (sections a. and b.(1), below) shall be calculated to three decimal places. Rates for Hourly Service (section b.(2), below) shall be calculated to two decimal places.

a. Long-Term Firm PTP Transmission Service and NT Service

The rate, in dollars per kilowatt per month ($/kW/mo), shall not exceed:

$$\frac{4(N_q + U_{q-1} + Z_{q-1})}{bd - 4S_q}$$

Where:

bd = ~~407,916~~470,532 MW-mo = Average of forecasted FY 2010~~08~~ and FY ~~2009~~ 2011 GSR Service billing determinants. Each annual billing determinant is the sum of the 12 monthly billing determinants.

N_q = Non-federal GSR cost to be paid by BPA-TS under a FERC-approved rate during the relevant quarter, as anticipated prior to the quarter. ($)

U_{q-1} = Payments of non-federal GSR cost made in the preceding quarter(s) that were not included in the effective rate for the preceding quarter(s). Any refunds received by BPA-TS would reduce this cost. U_{q-1} is a true-up for any deviation of non-federal GSR costs from the amount used in a previous quarter's GSR rate calculation. For calculating the GSR rate effective October 1, 2009~~7~~, U_{q-1} is zero. ($)

S_q = Reduction in effective billing demand for approved self-supply of reactive during the relevant quarter, as anticipated prior to the quarter. (MW-mo)

Z_{q-1} = A dollar true-up for under- or overstatement of reactive self-supply in rate calculations for the preceding quarter(s). For calculating the GSR rate effective October 1, 2009~~7~~, Z_{q-1} is zero. Z_{q-1} will be calculated by multiplying the under- or overstated megawatt amount of self-supply by the GSR rate that was effective during the quarter of self-supply deviation. ($)

"Relevant quarter" refers to the 3-month period for which the rate is being determined.

b. Short-Term Firm and Non-Firm PTP Transmission Service

(1) Monthly, Weekly, and Daily Firm and Non-firm Service

For each reservation, the rates shall not exceed:

(a) Days 1 through 5 ($/kW/day)

$$\textbf{Long-Term Service Rate} * \frac{\textbf{12 months}}{\text{52 weeks * 5 days}}$$

(b) Day 6 and beyond ($/kW/day)

$$\textbf{Long-Term Service Rate} * \frac{\textbf{12 months}}{\text{52 weeks * 7 days}}$$

(2) Hourly Firm and Non-Firm Service (mills/kilowatthour)

The rate shall not exceed:

$$\textbf{Long-Term Service Rate} * \frac{\cancel{\textbf{1000 Mills*}}\textbf{12 months}}{\text{52 weeks * 5 days * 16 hours}}$$

Where:

The "Long-Term Service Rate" specified in the formulas in sections 1.b.(1)(a) and (b), and 1.b.(2), above, is the rate determined in section 1.a., Long-Term Firm PTP Transmission Service and NT Service, in $/kW/mo.

2. BILLING FACTORS

a. Point-To-Point Transmission Service

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rates), the Billing Factor for each rate specified in section 1.a., 1.b.(1) and for Hourly Firm PTP Transmission Service specified in 1.b.(2) shall be the Reserved Capacity, which is the greater of:

1. the sum of the capacity reservations at the Point(s) of Receipt, or

2. the sum of the capacity reservations at the Point(s) of Delivery.

The Reserved Capacity for Firm PTP Transmission Service shall not be adjusted for any Short-Distance Discount or for any modifications on a non-firm basis in determining the Reactive Supply and Voltage Control from Generation Sources Service Billing Factor.

The Billing Factor for the rate specified in section 1.b.(2) for Hourly Non-Firm Service shall be ~~the scheduled kilowatthours. Upon 60 day's notice by BPA-TS, the Billing Factor for the rate specified in section 1.b.(2) for Hourly Non-Firm Service shall become the~~ Reserved Capacity and ~~.~~

~~When Reserved Capacity becomes the Billing Factor for Hourly Non-Firm Service,~~ the following shall apply:

i. If the need for Curtailment is caused by conditions on the Federal Columbia River Transmission System, the Billing Factor will be as follows:

a. If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted before the close of the hourly non-firm scheduling window, the Billing Factor will be the Reserved Capacity minus the curtailed capacity.

b. If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted after the close of the hourly non-firm scheduling window, the Billing Factor will be the Transmission Customer's actual schedule in the hour.

ii. If the need for Curtailment is caused by conditions on another transmission provider's transmission system, the Billing Factor will be the Reserved Capacity.

These Billing Factors apply to all PTP transmission service under the Open Access Transmission Tariff regardless of whether the Transmission Customer actually uses (schedules) the transmission.

b. Network Integration Transmission Service

For Transmission Customers taking Network Integration Transmission Service, the Billing Factor for the rate specified in section 1.a. shall equal the NT Base Charge Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-08).

c. Adjustment for Self-Supply

The Billing Factors in sections 2.a. and 2.b. above may be reduced as specified in the Transmission Customer's Service Agreement to the extent the Transmission Customer demonstrates to BPA-TS's satisfaction that it can self-provide Reactive Supply and Voltage Control from Generation Sources Service.

d. Adjustment for Customers Subject to the Unauthorized Increase Charge (UIC)

For Transmission Customers taking Point-to-Point Transmission Service (PTP, IS, and IM rate schedules) that are subject to a UIC in a billing month, the Billing Factor for the billing month shall be the Billing Factor calculated above plus the UIC Billing Factor calculated under section II.G.2.a. of the GRSPs.

For Transmission Customers taking Network Integration Transmission Service that are subject to a UIC in a billing month, the Billing Factor for the billing month shall be the Billing Factor calculated above plus the UIC Billing Factor calculated under section II.G.2.b. of the GRSPs.

Attachment 2
NT-~~08~~10
Network Integration Rate

SECTION I. AVAILABILITY

This schedule supersedes Schedule NT-~~06~~08. It is available to Transmission Customers taking Network Integration Transmission (NT) Service over Federal Columbia River Transmission System Network and Delivery facilities and to NT Transmission Customers taking Conditional Firm Service. Terms and conditions of service are specified in the Open Access Transmission Tariff. This schedule is available also for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§824j and 824k). Service under this schedule is subject to BPA-TS's General Rate Schedule Provisions (GRSPs).

Attachment 3
Attachment M
Procedures for redispatch

This attachment establishes parameters and procedures for redispatch of the federal hydro system and alternative means for redispatch by BPA's Power Services (PS) at the request of BPA's Transmission Services (TS). TS may request redispatch during any period when TS determines that a transmission constraint exists on the Transmission System and such constraint may impair the reliability of the system. TS may not request redispatch under this Attachment M to make additional firm or non-firm transmission sales.

Definitions
Under this Attachment M, redispatch includes:

1) the intentional incrementing or decrementing of generating units or projects by PS, or the limitation of generation at specific locations by PS, at the request of TS, and
2) transmission purchases and/or power purchases or sales made by PS to respond to requests for redispatch.

There are three types of redispatch under this Attachment M:

A. Emergency Redispatch is redispatch requested by TS upon declaration of a "system emergency" as that term is defined by the North American Electric Reliability Council (NERC).
B. NT Firm Redispatch is redispatch requested by TS for the purpose of maintaining firm network transmission (NT) schedules after TS has curtailed non-firm point-to-point (PTP) schedules and secondary network schedules in a sequence consistent with the NERC curtailment priority. For NT Firm Redispatch, TS shall request redispatch from PS and shall curtail firm PTP schedules in amounts proportionate to the non-secondary NT and firm PTP flows on the affected transmission flowgates at the time of the request.
C. Discretionary Redispatch is redispatch requested by TS prior to its curtailment of any firm or non-firm PTP schedules or secondary NT schedules for the purpose of avoiding or ameliorating curtailments.

Provisions
1. PS must comply with requests for Emergency Redispatch even if PS must violate non-power constraints.
2. PS must comply with requests for NT Firm Redispatch to the extent that it can do so without violating non-power constraints.
3. PS may respond to requests for Discretionary Redispatch by offering, at each generating unit or project, either no redispatch or any amount of redispatch up to the amount requested at each generating unit or project.
4. TS may request redispatch for the following maximum time periods:
    a) If TS requests redispatch before twenty minutes after the hour, TS may request redispatch only for the remainder of the hour.
    b) If TS requests redispatch at or after twenty minutes after the hour, TS may request redispatch for the remainder of the hour and the next hour.

c) If TS requests Discretionary Redispatch and, before the expiration of the period for which it has requested Discretionary Redispatch, requests NT Firm Redispatch at the same generating units or projects, the amount of Discretionary Redispatch, if any, that PS provided shall be treated as having been provided in response to the request for NT Firm Redispatch for purposes of calculating the proportionate amounts of non-secondary NT Redispatch and firm PTP curtailments that must take place in response to the OTC violation that resulted in the need for redispatch.

5. In response to any redispatch request, including requests for redispatch specific to Network Load located either within or outside of the BPA control area, PS may provide redispatch through redispatch of federal generation, purchases and/or sales of energy, or purchases of transmission. PS will inform TS at the time of the request if it intends to implement the redispatch through purchases or sales.

ATTACHMENT 2

SIGNATORIES TO THE
2010 TRANSMISSION RATE CASE
PARTIAL SETTLEMENT AGREEMENT

Asotin County PUD
Avista Corporation
Bandon, City of
Bonneville Power Administration Power Services
Chelan County Public Utility District No. 1
Clatskanie PUD
Cowlitz County PUD
Grant County Public Utility District
Iberdrola Renewables
M-S-R
Northwest Requirements Utilities

Signing for:
- Ashland, City of
- Benton Rural Electric Association
- Big Bend Electric Cooperative, Inc.
- Bonners Ferry, City of
- Burley, City of
- Cascade Locks, City of
- Central Lincoln People's Utility District
- Cheney, City of
- Columbia Basin Electric Cooperative, Inc.
- Columbia Power Cooperative
- Columbia River People's Utility District
- Columbia Rural Electric Association
- East End Mutual Electric Co., LTD.
- Ferry County Public Utility District No. 1
- Flathead Electric Cooperative
- Forest Grove, City of
- Glacier Electric Cooperative, Inc.
- Harney Electric Cooperative
- Hermiston Energy Services
- Heyburn, City of
- Hood River Electric Co-op
- Idaho County Light & Power
- Inland Power & Light
- Klickitat County PUD
- Kootenai Electric Cooperative, Inc.
- Lincoln Electric Cooperative, Inc.
- Lower Valley Energy
- McMinnville Water & Light

Midstate Electric Cooperative
Mission Valley Power
Missoula Electric Cooperative
Modern Electric Water Company
Monmouth, City of
Nespelem Valley Cooperative
Northern Wasco County PUD
Orcas Power & Light Cooperative
Oregon Trail Electric Cooperative
Peninsula Light
Ravalli County Electric Cooperative
Richland, City of
Rupert, City of
Salem Electric
Skamania County PUD
South Side Electric, Inc.
Surprise Valley Electrification Corp.
Tanner Electric Cooperative
Tillamook PUD
United Electric Cooperative
Vera Water & Power
Vigilante Electric Cooperative, Inc.
Wasco Electric Cooperative
Wells Rural Electric

PacifiCorp
Pend Oreille County Public Utility District
PNGC Power

Signing for:
Blachly-Lane Electric Cooperative
Central Electric Cooperative
Clearwater Power Company
Consumers Power Inc.
Coos-Curry Electric Cooperative, Inc.
Douglas Electric Cooperative
Fall River Rural Electric Cooperative, Inc.
Lane Electric Cooperative, Inc.
Lost River Cooperative
Northern Lights, Inc.
Okanogan County Electric Cooperative, Inc.
Raft River Rural Electric Cooperative, Inc.
Salmon River Electric Cooperative, Inc.
Umatilla Electric Cooperative
West Oregon Electric Cooperative, Inc.

Portland General Electric Company
Public Power Council
Seattle City Light

Snohomish County Public Utility District No. 1
Springfield Utility Board
Tacoma Power
TransAlta Energy Marketing (U.S.) Inc.
Troy, City of
Western Montana Electric Generating and Transmission Cooperative, Inc.
  Signing for:
  Flathead Electric Cooperative
  Glacier Electric Cooperative
  Lincoln Electric Cooperative
  Mission Valley Power
  Missoula Electric Cooperative
  Ravalli County Electric Cooperative
  Vigilante Electric Cooperative
Western Public Agencies Group
  Signing for:
  Alder Mutual Light Company
  Benton Rural Electric Association
  Eatonville, Town of
  Ellensburg, City of
  Elmhurst Mutual Power and Light Company
  Lakeview Light and Power Company
  Milton, City of
  Ohop Mutual Light Company
  Parkland Light and Water Company
  Peninsula Light Company
  Port Angeles, City of
  Public Utility District No. 1 of Clallam County
  Public Utility District No. 1 of Clark County
  Public Utility District No. 1 of Grays Harbor County
  Public Utility District No. 1 of Kittitas County
  Public Utility District No. 1 of Lewis County
  Public Utility District No. 1 of Mason County
  Public Utility District No. 3 of Mason County
  Public Utility District No. 2 of Pacific County
  Public Utility District No. 1 of Skamania County
  Public Utility District No. 1 of Wahkiakum County
  Tanner Electric Cooperative

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TESTIMONY OF

SARAH K. BERMEJO, DANNY L. CHEN, DAVID L. GILMAN,
BART MCMANUS, AND RONALD E. MESSINGER

Witnesses for Bonneville Power Administration

SUBJECT: ANCILLARY AND CONTROL AREA SERVICES

Page

TESTIMONY OF

SARAH K. BERMEJO, DANNY L. CHEN, DAVID L. GILMAN, BARTHOLOMEW A. MCMANUS, AND RON E. MESSINGER

Witnesses for Bonneville Power Administration

SUBJECT: ANCILLARY AND CONTROL AREA SERVICES

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Sarah Bermejo and my qualifications are contained in TR-10-Q-BPA-01.

A. My name is Danny Chen and my qualifications are contained in TR-10-Q-BPA-02.

A. My name is David Gilman, and my qualifications are contained in TR-10-Q-BPA-07.

A. My name is Bartholomew McManus, and my qualifications are contained in TR-10-Q-BPA-14.

A. My name is Ron Messinger and my qualifications are contained in TR-10-Q-BPA-15.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to provide an overview of the remaining portion of the 2010 Initial Proposal not included in the Partial Transmission Rate Case Settlement Agreement. *See* Bermejo *et al.*, Overview of Partial settlement, TR-10-E-BPA-06. This testimony sponsors the Ancillary and Control Area Services Rate Schedule, relevant portions of the General Rate schedule Provisions, and calculation of the ACS-10 rates. The Ancillary and Control Area Services discussed in this testimony include: Regulation and Frequency Response, Energy Imbalance, Generation Imbalance, Operating Reserve – Spinning Reserve, Operating Reserve – Supplemental Reserve, and Wind Integration – Within-Hour Balancing Service.

Q. How is your testimony organized?

A. The testimony is organized in six sections. Section 1 is the introduction and purpose of testimony. Section 2 provides an overview of Ancillary and Control Area Services. Section 3 discusses Regulation and Frequency Response Service. Section 4 discusses the Imbalance Service rates. Section 5 discusses the Operating Reserve Service rates. Finally, Section 6 discusses Wind Integration – Within-Hour Balancing Service.

Section 2: Overview of Ancillary and Control Area Services

Q. What are Ancillary Services?

A. Ancillary Services are needed with transmission service to maintain reliability within and among the Balancing Authority Areas affected by transmission service. These services range from actions taken to effect the transmission service transaction (such as scheduling and dispatching services) to services that are necessary to maintain integrity of the transmission system during a transmission service transaction (such as regulation, frequency, and reactive power support). Another Ancillary Service is needed to correct for the effects associated with undertaking a transmission service transaction (energy imbalance service). Furthermore, Operating Reserve services are needed to help assure reliability of energy delivery to loads in the event of a resource failure. BPA Transmission Services (BPA-TS) offers six Ancillary Services under its Open Access Transmission Tariff (Tariff): (1) Scheduling, System Control and Dispatch; (2) Reactive Supply and Voltage Control from Generation Sources; (3) Regulation and Frequency Response; (4) Energy Imbalance; (5) Operating Reserve – Spinning; and (6) Operating Reserve – Supplemental.

Q. What are Control Area Services?

A. Control Area Services are available to meet the reliability obligations of generation or loads in the BPA Balancing Authority Area (formerly known as the BPA "Control Area"). BPA-TS provides Control Area Services to generation or loads in the BPA

Balancing Authority Area that may not be taking transmission service from BPA-TS, but do impose reliability obligations on the BPA Balancing Authority that are not otherwise met. BPA-TS offers the following Control Area Services: Regulation and Frequency Response; Generation Imbalance; Operating Reserve-Spinning; Operating Reserve-Supplemental; and Wind Integration – Within-Hour Balancing. BPA determines such reliability obligations through application of NERC, WECC, and NWPP reliability standards for Balancing Authority Areas.

Q. Please identify the Ancillary and Control Area Services that BPA-TS is proposing to modify in the TS-10 Initial Proposal.

A. BPA-TS is proposing changes to the rates for Energy Imbalance Service, Generation Imbalance Service, Regulation and Frequency Response Service, Operating Reserve – Spinning Reserve Service, Operating Reserve – Supplemental Reserve Service, and Wind Integration – Within-Hour Balancing Service. BPA-TS is also proposing to modify the rate and the definition of Intentional Deviation for Imbalance Services.

Section 3: Regulation and Frequency Response Service

Q. What is Regulation and Frequency Response Service?

A. Regulation and Frequency Response Service provides the generation capability to (1) follow the moment-to-moment variations of loads in the BPA Balancing Authority Area and (2) maintain the power system frequency at 60 Hertz in conformance with NERC and WECC reliability standards.

Q. Who is charged for Regulation and Frequency Response Service?

A. Transmission Customers serving load in the BPA Balancing Authority Area are charged for Regulation and Frequency Response Service, as an Ancillary Service. In contrast, loads in the BPA Balancing Authority Area that are not served by BPA-TS transmission service are charged for the Control Area Service of Regulation and Frequency Response, unless the customer can demonstrate to BPA-TS's satisfaction that this obligation is met through other arrangements.

Q. What is the proposed rate for Regulation and Frequency Response Service?

A. The rate is 0.27 mills per kilowatt month. *See* Section 2 Study and Documentation for 2010 Ancillary Service and Control Area Services, TR-10-E-BPA-03.

Q. Are you proposing any other change to Regulation and Frequency Response Service?

A. No.

Section 4: Imbalance Services

Q. What are Imbalance Services?

A. Imbalance Services are energy services that are required to balance positive or negative deviations for load or generation in the BPA Balancing Authority Area. The two imbalance services are Energy Imbalance, which applies to load in the Balancing Authority Area, and Generation Imbalance, which applies to generation in the Balancing Authority Area.

Q. What is Energy Imbalance Service?

A. Energy Imbalance Service is provided when a load in the BPA Balancing Authority Area receives an amount of energy different from the amount that the customer scheduled for delivery during a schedule hour. To the extent that the BPA Balancing Authority absorbs or delivers an amount of energy that is different from the amount the customer scheduled for its load, BPA provides Energy Imbalance Service.

Q. What is Generation Imbalance Service?

A. Generation Imbalance Service is provided when a generator in the BPA Balancing Authority Area generates an amount of energy different from the amount that the customer scheduled for delivery from the generator during a schedule hour. To the extent that the BPA Balancing Authority absorbs or delivers an amount of energy in an hour that is different from the amount the customer scheduled for its generation, BPA provides Generation Imbalance Service.

Q. *What does "positive deviation" mean in relation to Imbalance Services?*

A. For Energy Imbalance, a positive deviation occurs when a customer takes more energy in an hour than the customer scheduled for that hour. For Generation Imbalance, a positive deviation occurs when the amount the customer scheduled for the hour is greater than the customer's actual generation in an hour.

Q. *What does "negative deviation" mean in relation to Imbalance Services?*

A. For Energy Imbalance Service, a negative deviation occurs when energy delivered to the customer is less than the amount that the customer scheduled for the hour. For Generation Imbalance, a negative deviation occurs when the amount the customer scheduled for the hour is less than the customer's actual generation in an hour.

Q. *What is an Intentional Deviation for Imbalance Services?*

A. An Intentional Deviation for Imbalance Services is a positive or negative deviation that BPA-TS determines to be intentional. The criteria BPA-TS uses to make this determination is as follows: An Intentional Deviation is a positive or negative deviation that (1) persists during multiple consecutive hours or at specific times of the day; (2) constitutes a pattern of under-delivery or over-use of energy; or (3) constitutes persistent over-generation or under-use during Light Load Hours, particularly when the customer does not respond by adjusting schedules for future days to correct these patterns.

Q. *What is the difference between an Unauthorized Increase Charge and an Intentional Deviation?*

A. An Unauthorized Increase Charge applies when a point-to-point transmission customer exceeds its capacity reservation at any Point of Receipt or Point of Delivery. The amount of Reserved Capacity is the key factor in BPA-TS' determination of an

Unauthorized Increase Charge. In contrast, an Intentional Deviation applies when there is a positive or negative deviation from the schedule that is persistent or otherwise meets the criteria as discussed above. The amount of Reserved Capacity used during an hour is irrelevant to BPA's determination of an Intentional Deviation. An Intentional Deviation may apply in addition to an Unauthorized Increase Charge if the customer's transmission schedule exceeds its Reserved Capacity and the positive or negative deviation satisfies the criteria under Intentional Deviation.

Q. Please describe BPA-TS's proposed changes to the definition of Intentional Deviation.

A. BPA-TS proposes to modify the Intentional Deviation definition to classify schedule deviations that occur for 3 or more consecutive hours at an amount greater than 15% of the schedule or 20 MW as Intentional Deviations. In such situations, all consecutive hours meeting this condition will also be considered intentional deviation and will be subject to financial penalty. This applies to both Generation and Energy Imbalance Service customers.

BPA-TS is no longer proposing to include as an Intentional Deviation the situation where a customer submits a generation schedule (i.e., generation estimate) to BPA-TS that does not match the sum of the customer's transmission schedules. This modification is currently listed under the definition of Intentional Deviation in Section III of the proposed GRSPs. Based on internal review and feedback from customers, BPA-TS will continue to review new technology and its internal administrative procedures to address the problem that arises when a generation schedule does not match corresponding transmission schedules. BPA-TS intends to hold a public process to modify BPA-TS business practices to address this issue. Thus, BPA-TS is not proposing this change for the FY2010-11 rate period.

Q. Why is BPA-TS proposing to modify the definition of Intentional Deviation?

BPA-TS is concerned about reliability impacts that result from excessive positive or negative deviations that persist for three or more hours. In recent years, BPA-TS has observed large and persistent scheduling deviations from generation in the BPA Balancing Authority Area. BPA-TS depends on the Federal hydro system to provide balancing reserves, which must be available each hour to maintain load and resource balance within the BPA Balancing Authority Area. When large and persistent deviations are observed within the BPA Balancing Authority Area, BPA must adjust its reserves to accommodate those deviations. Even if BPA does not exhaust its total reserves during an hour, a generator in BPA's Balancing Authority that produces large and persistent deviations will contribute to operational changes of the Federal hydro system to maintain the necessary level of reserves for future hours. Under extreme conditions, BPA's ability to respond to unexpected imbalances in future hours may be reduced because of those operational changes in previous hours.

Generally, a customer should be able to modify its schedules after observing two hours of large deviations. BPA considers three hours to be adequate time for a customer to notice and fix an imbalance that exceeds 15% of the customer's hourly transmission schedule for the hour or 20 MW. Under current scheduling practices, a customer may adjust its generation schedule (i.e., generation estimate) up to 30 minutes before the start of the next hour. This time period is known as the scheduling window. If a customer observes a large positive or negative deviation during the scheduling window, the customer has the ability to adjust its generation estimate to reduce the imbalance before the scheduling window closes for the next hour. During the second hour, if the customer is monitoring its schedules, the customer can modify its transmission schedule before the scheduling window closes for the third hour to avoid the large positive or negative deviation. Accordingly, the customer should be able to adjust its generation estimate to avoid persistent large deviations that occur for three or more hours, and therefore it is appropriate to consider large deviations that extend for three or more hours to be intentional.

Q. Please describe the proposed change in the Imbalance Services' rate for Intentional Deviation.

A. BPA-TS is proposing to increase the rate that applies to positive deviations that BPA-TS determines to be Intentional Deviations from 125% to 150% of BPA's highest incremental cost that occurs during that day.

Q. Why is BPA-TS changing the rate for Intentional Deviation?

A. Currently, the rate of 125% (of BPA's highest incremental cost that occurs during that day) is the same rate that applies to generation or energy imbalances within Deviation Band 3. Since the Intentional Deviation rate only applies to positive or negative deviations that are either excessive or persistent, the rate should be higher than the normal rate charged under Deviation Band 3. Therefore, the proposed rate is an appropriate price signal to incentivize good scheduling behavior.

Q. Please describe BPA-TS's proposed modifications to the Imbalance Service rate schedules to address negative energy prices.

A. BPA-TS is proposing to include new language in the BPA Incremental Cost, Spill Conditions, and Intentional Deviation rate provisions to address the effect of negative energy prices. First, BPA-TS proposes to modify the language under "BPA Incremental Cost" to clarify that BPA-TS will not give a credit to the customer for positive deviations if the deviation occurs in an hour that the energy index used for BPA Incremental Cost is negative.

In addition, BPA-TS is proposing to add language under "Spill Conditions" to clarify BPA-TS's treatment of imbalances when the energy index is negative and the

Federal System is in a Spill Condition. If the energy index is negative during a Spill Condition, BPA-TS proposes to no longer provide credit to the customer for negative deviations within Deviation Band 1. If during Spill Conditions a negative deviation is in either Deviation Band 2 or 3, BPA-TS will charge the customer the index price for the negative deviation that occurred in the hour that the energy index is negative. If the energy index is negative for an hour in which the imbalance is determined to be an Intentional Deviation by BPA-TS, BPA-TS proposes to charge the customer the energy index price for that hour.

Q. Why is BPA-TS proposing a change to the Imbalance rates when a negative energy index occurs?

A. BPA-TS is proposing to address negative energy index prices because negative pricing undermines the incentives created by Energy and Generation Imbalance Service. Under the Energy and Generation Imbalance Service rate schedules, BPA determines its incremental cost for positive and negative deviations based upon an hourly energy index in the Pacific Northwest. The current index used in the Pacific Northwest is the Dow Jones Mid-Columbia Daily (Dow Jones Mid-C) energy index. In FY 2008, BPA observed negative energy prices in the Dow Jones Mid-C energy index for some Light Load Hours on 18 different days. The minimum, maximum, and average negative index prices were \$(7.50), \$(0.04), and \$(1.44), and occurred during Light Load Hours. During such days, BPA observed those negative energy index prices to coincide with Spill or near Spill Conditions (e.g., when there is more hydro generation than load and spill is limited by non-power constraints).

When the energy index prices are negative, an incentive materializes for customers to either generate less than scheduled (for Generation Imbalance Service) or take less energy than scheduled (for Energy Imbalance Service) because positive deviations result in credits to the customer. Thus, BPA-TS would have to pay entities that did not schedule accurately to serve the entities' load when the price is negative, which is likely to be during Spill Conditions. Since BPA-TS does not know if and when a customer will have a positive deviation until after the scheduling hour, BPA-TS cannot plan to operate its system to gain a benefit from positive deviations when the energy index is negative. If the Pacific Northwest begins to observe negative energy index prices more often, customers will have a greater incentive to schedule inaccurately under Spill Conditions to receive credits from BPA-TS. Conversely, the penalty deviation bands in Energy and Generation Imbalance Service become less effective as incentives for customers to schedule accurately. For these reasons, BPA-TS proposes to no longer provide credit for positive deviations when the energy index is negative.

For negative deviations, BPA-TS must maintain load and resource balance to preserve reliability; thus, BPA typically spills water to reduce its hydro generation if BPA has excess generation in the Balancing Authority Area. However, if the Federal System is in Spill Conditions, BPA's ability to reduce hydro generation is limited by spill's impact on total dissolved gas levels in the river. If energy prices are negative and customers produce negative deviations under such Spill Conditions, BPA may need to pay third-party entities to take energy from the Federal hydro system to avoid additional spill that in turn increases the risk of higher nitrogen saturation levels that are dangerous to fish. However, BPA's ability to find entities to take excess energy from the BPA system depends on unforeseeable market conditions. Thus, negative energy prices make it necessary for BPA to change the Imbalance rates to provide a clear price signal to avoid potential impacts on reliable system operation and BPA's non-power constraints. Accordingly, BPA-TS proposes to charge the customer the negative index price as an incentive to avoid negative deviations when the energy index is negative and BPA is in

Spill Conditions. BPA-TS proposes to calculate the charge by multiplying the negative deviation by the negative index price, which would result in a positive net charge.

Q. Is BPA-TS proposing any other change to the Energy Imbalance Service rate schedule?

A. No.

Q. Is BPA-TS proposing any other change to the Generation Imbalance Service rate schedule?

A. No.

Section 5: Operating Reserve

Q. What is Operating Reserve?

A. Operating Reserve is the generating capacity necessary to replace generating capacity and energy lost due to forced outages of generation or transmission equipment. Operating Reserve is required for the reliable operation of the interconnected power system. Within a Balancing Authority Area, adequate generating capacity must be available at all times to maintain scheduled frequency and to avoid loss of firm load following transmission or generation contingencies. Operating Reserve is described as contingency reserves in the WECC standard, but for the purpose of this testimony, BPA-TS refers to contingency reserves as Operating Reserve.

Q. What is Spinning Operating Reserve?

A. Spinning operating reserve is reserve provided by the unloaded generating capacity of the system's firm resources that are synchronized to the power system and ready to serve additional demand. These firm resources can respond immediately to system frequency deviations occurring from a system disturbance. They must be capable of fully responding within 10 minutes. WECC requires that each balancing authority maintain a Spinning Reserve obligation equal to a minimum of 50 percent of its Operating Reserve obligation.

Q. *What is the proposed rate for Spinning Operating Reserve Service?*

A. The rate is 11.14 mills per kilowatthour. *See* Study and Documentation for 2010 Ancillary Service and Control Area Services, TR-10-E-BPA-03 at Table 1.

.*Q.* *What is Supplemental (Non-Spinning) Operating Reserve?*

A. Supplemental reserve means generating capacity not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time. This capacity must be fully deployable within 10 minutes of notification, but is not required to immediately respond to a contingency like Spinning Reserve. Supplemental Operating Reserve is the portion of the total Operating Reserve obligation that does not meet the definition of Spinning Reserve.

Q. *What is the proposed rate for Supplemental Operating Reserve Service?*

A. The rate is 9.85 mills per kilowatthour. *See* Study and Documentation for 2010 Ancillary Service and Control Area Services, TR-10-E-BPA-03 at Table 1.

Q. *How are the rates for Operating Reserve being established?*

A. BPA-TS uses the revenue requirement from the generation input cost in the BPA-PS Initial Proposal, Generation Inputs Study, WP-10-E-BPA-08. No additional transmission costs are added to such generation input costs. The revenue requirement is $25.042 million for spinning reserves and $22.131 million for supplemental reserves. *Id.* To calculate the rate for Spinning Operating Reserve, BPA-TS proposes to divide the annual revenue requirement for Spinning Reserve by the billing factor for Spinning Reserve. Similarly, for Supplemental Operating Reserve, BPA proposes to divide the annual revenue requirement for Supplement Reserve by the billing factor to obtain the rate. *See* Section 3.5 of Study and Documentation for 2010 Ancillary Service and Control Area Services, TR-10-E-BPA-03.

Q. *Is there any difference in how the revenue requirement was established this year?*

A. Yes. The per unit costs provided by BPA-PS resulted in different rates for spinning and supplemental reserve. In previous rate cases the rates for spinning and supplemental reserve were the same. For FY 2010-11, the differences in the rates are due to a variable cost component that is added for spinning reserve but not for supplemental reserve. *See* Bolden *et al.*, Operating Reserve Cost Allocation, WP-10-E-BPA-08 and J. Bermejo & Beale, Variable Cost Pricing Methodology, WP-10-E-BPA-25.

Q. How is the forecasted use of the service established?

A. BPA-PS provides the generation inputs for Operating Reserve based on a BPA-TS forecast of BPA-TS needs. BPA-TS forecasts the BPA-PS generation input requirement based on the historical Operating Reserve requirement in the BPA Balancing Authority Area. *See* Section 5 of Operating Reserve Cost Allocation, WP-10-E-BPA-08.

Q. What is the WECC Operating Reserve requirement that applies to Balancing Authority Area Operators?

A. The current WECC standard for Operating Reserve (BAL-STD-0002-0) sets a minimum amount of spinning and non-spinning reserve that must be set aside for each Balancing Authority. The minimum contingency reserve is the greater of (a) the loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency; or (b) the sum of 5% of load responsibility served by hydro and 7% served by thermal generation. NWPP members use 5% of load responsibility served by wind generation. At least half of the reserve must be spinning reserve. *See* Bolden *et al.*, WP-10-E-BPA-26.

Q. When is Operating Reserve needed?

A. Operating Reserve is needed to replace generating capacity and energy lost due to generation contingencies across member Balancing Authorities. According to the NWPP, a contingency occurs when generation is lost due to unit trips, loss of the transmission path between generator and the network point of interconnection, internal plant problems, or failure of a generating unit to start.

Q. Are transmission customers allowed to obtain Operating Reserve from other suppliers?

A. Yes. The BPA-TS Tariff allows transmission customers the option of obtaining Operating Reserve either by (1) self-supply; (2) purchase from a third party; or (3) purchase from BPA-TS. Currently the BPA-TS Business practice for Operating Reserve allows transmission customers to make a two year election to have as their supplier BPA-TS or another supplier. The Transmission Customer has the option to change non-BPA-TS suppliers annually. If the customer does not make an election or if the transmission customer does not elect another supplier, the customer must purchase Operating Reserve from BPA-TS.

Q. What happens if a customer that self-supplies or acquires Operating Reserve from a third party fails to meet BPA-TS's Operating Reserve criteria?

A. If a supplier fails to meet the criteria in the BPA-TS Operating Reserve business practice, it will be in default and the supplier's ability to supply Operating Reserve services will be suspended for the remainder of the two-year election period. BPA will become the supplier and the customer being supplied will be charged the default rate for the remainder of the period.

Q. What is the proposed default rate for Spinning Operating Reserve Service?

A. The rate is 12.82 mills per kilowatthour. *See* Study and Documentation for 2010 Ancillary Service and Control Area Services, TR-10-E-BPA-03 at Table 1.

Q. What is the proposed default rate for Supplemental Operating Reserve Service?

A. The rate is 11.33 mills per kilowatthour. *Id*.

Q. *How is the default rate determined?*

A. The default rate is a penalty rate to encourage customers to meet their commitment to self-supply or third-party supply Operating Reserve. The rate is 15% higher than the rate for normal service, and is the same percentage used in the 2008 Rate schedules. BPA considers this to be a reasonable penalty at this time. No parties have defaulted in the 2008-09 rate period as of January 2009. It is applied the same as the normal rate to the billing factors of those customers where the supplier has defaulted.

Q. Please describe any proposed WECC standards for Operating Reserve that could be effective during the 2010-2011 rate period.

A. WECC has proposed a new standard for Operating Reserve, BAL-002-WECC-1 Contingency Reserves. The new proposed WECC standard for operating reserve represents a reduced allocation of reserves based on a combination of generation and load. The proposed standard states that the minimum operating reserve requirement is the greater of (i) the sum of 3% of load (generation minus station service minus Net Actual Interchange) and 3% of the net generation (generation minus station service) or (ii) the most severe single contingency. Additionally, like today's standard, at least half of the total requirement must be spinning reserve. This new standard, if adopted by the Federal Energy Regulatory Commission (Commission), will replace the current minimum reserve requirement of 5% of hydro and 7% of thermal on-line generation. We forecast the net impact to be approximately 132 aMW less average Operating Reserve needed each year of the rate period to meet reliability standards. Section 3 Operating Reserve Cost Allocation, WP-10-E-BPA-08. The proposed standard has received NERC approval but is waiting for Commission approval for implementation.

Q. How will Transmission Services adjust the billing factors for Operating Reserve if the WECC standard is effective during the rate period?

A. BPA will adjust the Operating Reserve billing factor in accordance with the prevailing WECC standard (expected to be BAL-002-WECC-1 Contingency Reserves) and will post on its OASIS the new billing factors when the Commission adopts the new standard.

Q. If the Commission approves the new WECC standard before the Administrator establishes final rates for the FY 2010 rate period, how will BPA determine the rate for Operating Reserve?

A. If the Commission approves the new WECC standard before the Administrator's rate decision for the rate period, BPA-TS would calculate the rate based on the new billing factors and the generation input cost determined in the WP-10 subdocket. The BPA-PS generation input per unit cost would also be based on the new WECC standard, along with other updates that will affect generation input costs. *See* Bolden *et al.*, WP-10-E-BPA-26. However, the effect of those changes is unknown at this time, but BPA expects that such changes may result in a higher Operating Reserve rate if the Commission approves of the new WECC standard. *See Id.*

Q. If the Commission approves the new WECC standard after the rate period begins, how will this affect the Operating Reserve rate?

A. If the Commission does not approve the new WECC standard before the Administrator makes a final decision on the proposed rates, BPA will forecast the billing factors based on the best information available about the timing and likelihood of the Commission's decision to adopt or reject the new WECC standard.

If the Administrator makes a final decision to base the rates for Operating Reserve on the current WECC standard (5% of load served by hydro and 7% of load served by thermal generation), such Operating Reserve rates would remain the same (including the default rates for each) over the rate period even if the Commission adopts the new WECC standard during the rate period. BPA cannot adjust the Operating Reserve rate during the rate period since the rates for Operating Reserve would have already been established in this docket, and the generation input costs will have already been established in the WP-10 sub-docket. Section 5.10 Operating Reserve Cost Allocation, WP-10-E-BPA-08. However, BPA would update the billing factors, but not the rates, for Operating Reserve under that scenario.

Q. If the Commission approves of the new WECC standard before the Administator's final decision on the Operating Reserve rate, how would the new WECC standard impact transmission customers over the rate period?

A. If the Commission adopts the new WECC standard, the total required amount of Operating Reserve will be reduced in the BPA Balancing Authority Area. However, since the generation input costs that are established by BPA-PS may increase (*See, e.g.,* Bolden *et al.*, WP-10-E-BPA-26), such costs would be passed through to transmission customers through a corresponding transmission rate increase for Operating Reserve.

Section 6: Wind Integration - Within-Hour Balancing Service

Q. Please briefly describe Wind Integration – Within-Hour Balancing Service.

A. Wind Integration – Within-Hour Balancing Service provides the generation capability (ability to both increase and decrease generation) to follow within-hour variations of wind resources in the BPA Balancing Authority Area. Within-Hour Balancing Service is required to maintain the power system frequency at 60 Hertz in conformance with NERC and WECC reliability standards and provide the regulation, following and imbalance reserve needed to support wind resources.

Q. Please explain the relationship of the Wind Integration – Within-Hour Balancing Service Rate to the Generation Imbalance Service Rate.

A. The Wind Integration – Within-Hour Balancing Service Rate recovers the costs BPA incurs for setting aside and using balancing reserve capacity to balance the output of wind resources within-hour. In contrast, the Generation Imbalance Service rate settles the energy cost differences associated with the hourly generation imbalances after the fact. The generation imbalance penalties (i.e., imbalances in Deviation Bands 2 and 3) are designed to incentivize good scheduling behavior and do not recover the costs for balancing reserve capacity.

Q. Please explain the difference between Wind Integration – Within-Hour Balancing Service and Regulation and Frequency Response Service.

A. Regulation and Frequency Response service provides balancing for the moment-to-moment variations in load, while Wind Integration – Within-Hour Balancing Service provides balancing, including the moment-to-moment regulating reserve component, for wind resources. The variability of both wind resources and loads contributes significantly to the total balancing requirement of the BPA Balancing Authority Area.

Q. What is the proposed Wind Integration – Within-Hour Balancing Service rate?

A. The proposed rate is 2.72 $/kW-mo.

Q. How did you calculate the proposed Wind Integration – Within-Hour Balancing Service rate?

A. The proposed rate of 2.72 $/kW-mo is determined by dividing the annual revenue requirement of $122,153,911 by 12 months and then dividing by the forecasted average monthly installed wind generating capacity of 3,741,792 kW. Section 4.5 Study and Documentation for 2010 Ancillary Service and Control Area Services, TR-10-E-BPA-03.

Q. How did you determine the revenue requirement?

A. BPA calculated a reserve requirement of 1041.6 MW to increase generation and 1,479.8 MW to decrease generation to be the rate period average amount of balancing reserve capacity required to support the forecasted monthly installed wind generating capacity. McManus et al., WP-10-E-BPA-08. BPA-PS calculated an annual revenue requirement of $104,343,366 for FY 2010 and $139,962,456 for FY 2011 for an average annual revenue requirement of $122,153,911. *Id.*, section 1; Fisher *et al.*, WP-10-E-BPA-24; J. Bermejo, WP-10-E-BPA-25; *see also*, Section 4.5 Study and Documentation for 2010 Ancillary Service and Control Area Services, TR-10-E-BPA-03.

Q. How did you calculate the forecasted average monthly installed wind generating capacity?

A. The monthly forecast of installed wind generating capacity for the rate period is identified in the reserve forecast study. *See* McManus *et al.*, WP-10-E-BPA-23.

Q. How will you determine the billing factor for installed capacity for purposes of applying the rate?

A. BPA-TS will determine the installed capacity for each wind plant in the BPA Balancing Authority Area each month during the rate period based on the total installed generating units (wind turbines) and unit capacity of each wind generator. For wind projects that have completed installation of all units, the installed capacity will be the aggregate nameplate of the generating units. For wind projects for which some but not all units are installed before the 15th of the month that is prior to the billing month (that is, some units are generating energy), the installed capacity will be the wind project's highest hourly output from the wind generator measured from the time of the initial operation up to the end of the 15th day of the month prior to the billing month. Using the maximum hourly output of the generating units enables BPA-TS to approximate the total installed capacity for wind projects that are still under construction. This approximation is necessary for wind projects still under construction because BPA-TS will not know the exact amount of installed capacity at any given time.

This method for measuring the installed capacity of incomplete wind projects ensures that for each billing month, the billing factor will be as close as possible to the project's installed capacity without being greater than the project's installed capacity (since the project cannot generate more than its capacity). In addition, using the 15th day of the month as a cutoff date provides BPA-TS sufficient time to prepare for the monthly billing. Additional wind turbines installed after the 15th will be picked up during the next monthly billing cycle. This adjustment only applies to wind generators that are under construction. Once construction of the wind project is complete, BPA requires each wind generator to submit in writing the aggregate nameplate of wind generator's generating units. If the generator does not respond to BPA-TS's request to supply its nameplate capacity after installation, BPA-TS will use the best information available (e.g., the installed capacity listed in the customer's interconnection agreement) to determine installed capacity of the generating facility.

Q. Why is BPA-TS using the monthly installed capacity as the billing factor?

A. Since a wind generator is capable of generating up to its nameplate capacity once it is interconnected to the BPA transmission system, the balancing reserve capacity required to balance wind is a function of installed wind capacity. BPA based the amount of balancing reserve capacity that must be set aside for this service on the forecasted monthly installed wind generation capacity in BPA's Balancing Authority Area. *See* McManus *et al.*, WP-10-E-BPA-23. Therefore, charging the rate based on installed capacity is consistent with the principles of cost causation.

Q. Did you consider other rate design options?

A. Yes. BPA-TS considered a formula rate design that would recover the cost of wind balancing services and any stranded costs that result from a wind generator's election to self-supply, or acquire from third parties, wind balancing services. However, this approach is overly complex and would increase the cost for generators that do not self-supply or acquire from third-parties wind balancing services. Thus, BPA-TS proposes to use a simple rate design for the rate period.

Q. Has BPA considered acquiring generation inputs for balancing services from third party suppliers?

A. Yes. BPA submitted a request for information in August 2008 seeking information about available sources of generation inputs for load following and regulation to augment generation inputs provided by the federal hydro system. BPA is proposing to proceed with this effort as a pilot program aimed at developing, testing, evaluating and acquiring third party supply generation inputs to support incremental wind integration in the BPA Balancing Authority Area. *See* Mainzer *et al.*, WP-10-E-BPA-22.

Q. How will BPA's Request for Information for third party supply affect the Wind Integration – Within-Hour Balancing Service Rate?

A. BPA-TS proposes to increase its program spending levels by including in its general revenue requirement $5 million each year for a total of $10 million to fund the pilot program over the rate period. The decision to increase the program spending forecast will be discussed outside of this rate proceeding in the Integrated Program Review process scheduled to begin in March 2009. *See* Homenick *et al*., TR-10-E-BPA-06, at 3. Since BPA intends to implement third party supply of generation inputs on a pilot program basis, it is premature to forecast a significant quantity of third party supplied generation inputs or revenues associated with third party supply for FY 2010-11. *See*

Mainzer *et al.*, WP-10-E-BPA-22. Therefore, BPA's proposed pilot program is not included in the Wind Integration – Within-Hour Balancing Service rate.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY OF

MARK A. JACKSON, , ROBERT D. KING, ALEXANDER LENNOX

Witnesses for Bonneville Power Administration

SUBJECT: INCREMENTAL COST RATE

Section 1: Introduction and Purpose of Testimony

Q. Please state your name and qualifications.

A. My name is Mark A. Jackson. My qualifications are stated in TR-10-Q-BPA-09.

A. My name is Robert D. King. My qualifications are stated in TR-10-Q-BPA-11.

A. My name is Alexander Lennox. My qualifications are stated in TR-10-Q-BPA-12.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor the proposed Incremental Cost Rate in BPA's proposed PTP-10 and NT-10 rate schedules.

Q. How is your testimony organized?

A. The first part is this introduction. The second part is a general definition of the Incremental Cost Rate. The third part describes the steps in the proposed Incremental Cost Rate public process for initial Incremental Cost Rates. The fourth part describes the implementation of the proposed Incremental Cost Rate. The fifth part describes BPA's consideration of other alternative approaches.

Section 2: Definition of Incremental Cost Rate

Q. Please briefly describe the proposed Incremental Cost Rate.

A. The proposed Incremental Cost Rate is a formula rate that would allow BPA to allocate the costs of new transmission facilities needed to provide new PTP service or service for new Network Resources or new Network Loads, when the Incremental Cost Rate is higher than the embedded cost rate for such service, including the costs of the new facilities.

Q. *What are embedded cost rates?*

A. Embedded cost rates result from spreading the costs of BPA's Integrated Network across all the users of the Network. BPA's Point-to-Point (PTP) and Network Integration Service (NT) rates are embedded cost rates.

Q. *Does BPA propose to charge both an embedded cost rate and the Incremental Cost Rate for the same service?*

A. For PTP service, BPA proposes to charge either the embedded cost rate or the Incremental Cost rate, but not both for the same service. For NT service, as described below, BPA proposes to charge the Incremental Cost Rate for new Network Resources or new Network Loads and also charge the embedded cost rate.

Q. *Please describe what costs BPA would allocate to Incremental Cost Rates.*

A. We would allocate total construction costs plus operation and maintenance costs for the proposed new facilities, minus the present value of any planned reliability projects that would be displaced or deferred to a future date by the proposed new facilities. If the proposed new facilities accelerate the need for a reliability project we were planning to build in the future, the acceleration costs of the project would also be allocated to the Incremental Cost Rate.

Q. *Will BPA hold a public process to discuss the allocation of Incremental Cost Rates?*

A. Yes. BPA will hold a public process for determining and allocating costs when BPA offers transmission service at the Incremental Cost Rate. The steps for the public process and implementation of the Incremental Cost Rate are described in the following sections.

Section 3: Steps in the Public Process for the Proposed formula Incremental Cost Rate

Q. *What are the steps in applying BPA's proposed Incremental Cost Rate formula for the initial Incremental Cost Rates?*

A. After BPA has completed a System Facilities Study or a Network Open Season Cluster Study under its OATT and determines that new facilities are required to satisfy a transmission request, BPA will decide if it can offer service at an embedded cost rate. If BPA has determined that it cannot provide the service at the embedded cost transmission rate, then under BPA's OATT, the customer must agree to fund an environmental review to remain in the queue. If the customer agrees, then after completion of environmental review for the transmission system upgrades, BPA will prepare proposed Incremental Cost Rates, proposed Embedded Cost Rates as defined in the proposed Incremental Cost Rate including the costs of the facility upgrades needed for the Application, a proposed allocation of the new facilities costs to embedded cost rates for eliminated or deferred reliability project costs if applicable, supporting documentation described in the proposed Incremental Cost Rate, and BPA's proposed timeline for completing Incremental Cost Rate offers. BPA will then post the proposed rates, supporting documentation, and timeline. At such time, BPA will hold a public meeting to discuss this information with any customers and other interested parties.

Q. Will BPA provide interested parties an opportunity to respond to the proposed rates and supporting documentation?

A. Yes. Interested parties may ask questions and provide comments at the public meeting. If interested parties have additional questions after the meeting, they may submit them, or submit data requests, in writing to BPA within the time provided in the rate schedule, and BPA will respond and post the questions, data requests and responses. If customers have additional comments, they may then submit them and BPA will respond.

Q. What is the purpose of the public process?

A. The public process allows proposed Incremental Cost Rate customers to clarify their understanding of the rate and challenge costs BPA proposes to allocate to the rate. It also allows other transmission customers the opportunity to challenge an alleged failure to allocate sufficient costs to the Incremental Cost Rate. The outcome of this public process will provide BPA with information to make a well-informed decision on incremental costs that factor into the Incremental Cost Rate calculation.

Q. Are there other benefits to this process?

A. Yes. The proposed public process allows BPA to extend the timeline to conduct settlement negotiations if there is a dispute concerning the proposed Incremental Cost Rates. Such negotiations could allow the customers to reach agreement to enable construction of the new facilities and to provide the requested service.

Q. Will BPA provide advance notice to customers of the public meeting to discuss incremental cost rates?

A. Yes. BPA will provide advance notice of public meetings, similar to any other public meeting, to determine and allocate costs associated with BPA offers of transmission service at an Incremental Cost Rate. The Agency Calendar available on the BPA external website will also provide meeting details.

Q. Does BPA propose to apply this public process to the adjustments to the initial Incremental Cost Rate, as described below?

A. No.

Section 4: Implementation of the Incremental Cost Rate

Q. Will BPA require customer funding for Incremental Project Costs, which are defined in the proposed Incremental Cost Rate?

A. BPA will make decisions related to requiring advance funding outside of rate case proceedings. If BPA requires advance funding, that requirement will be explicit in any offers of transmission service at Incremental Cost Rates.

Q. If BPA does require advance funding, how will BPA return the advance to participating customers?

A. The customer will receive transmission credits that will be applied against the non-usage sensitive portion of their transmission bill for those reservations requiring the new facility. The amount of the credit will reduce the customer's outstanding advance funding balance, which will be the sum of the customer's funds advanced for use in construction and interest that accrues on the outstanding balance.

Q. *Does BPA propose to treat Point-to-Point and Network Integration customers differently in the Incremental Cost Rate?*

A. Yes, there are some differences between PTP and NT Incremental Cost Rates. For the PTP Incremental Cost Rate, the billing factor is the demand for reservations that require the new facilities. For the NT Incremental Cost Rate, the billing factor is the capacity required for the new Network Resource (demand designation) or new Network Load that requires the new facilities. Also, NT customers will be charged the embedded cost NT Base Charge in addition to the Incremental Cost Rate, as discussed below.

Q. *Why is the different treatment appropriate?*

A. NT and PTP service are fundamentally different services. PTP service is for a fixed demand between two points. If the PTP customer pays the Incremental Cost Rate for new service, other customers are protected from the additional costs needed to provide that service and are not assigned more costs than they would have been without the new PTP service. NT service is used to transmit power from multiple Network Resources to multiple customer points of delivery. The billing factor for the embedded cost NT rate is based on the customer's Network Load. When an NT customer requests service for a new Network Resource or a new Network Load, that customer is using the existing system for its existing Network Resources and existing Network Load, and causing new facilities to be built for the new Network Resource or Load. If the NT customer were not charged the embedded cost rate for existing Network Resources and Loads, then the system costs incurred to serve the existing Network Resources and Loads would be spread to other transmission customers while the NT customer continued to use the existing system in addition to the new facilities.

Q. Are there other reasons for the different treatment?

A. Yes. Because the Network Load varies from forecast, BPA would over or under-recover the costs of the new facilities each month if BPA charged only an Incremental Cost Rate based on the forecast Network Load.

Q. How does the Incremental Cost Rate treat changes in use of paths that are subject to the Incremental Cost Rate?

A. Once the initial Incremental Cost Rates are established for a path subject to the Incremental Cost Rate, BPA will make annual adjustments to those rates to reflect any revenues received for long-term or short-term use of the path subsequent to the initial rate or to the last adjustment. Those annual adjustments could also reflect a reduction in short-term use of the path, resulting in an increase in the Incremental Cost Rate. Since any additional long term use would be expected to amortize its share of Incremental Project Costs over the term of the request, a reduction in long term use that results from expiration of a long term reservation would not increase the Incremental Cost Rate. As a result of an adjustment, BPA will not increase an Incremental Cost Rate above the initial rate level.

Q. Please explain how this proposal fairly allocates costs between existing and new transmission service.

A. The cost allocation of new facilities between embedded cost rates and Incremental Cost Rates will reflect the cost-causation for the new facilities. Where the Integrated Network receives a reliability benefit from the new facilities by the delay or elimination of a reliability upgrade, the cost allocation will reflect those benefits in the embedded cost rates. The Incremental Cost Rates will recover the incremental costs allocated to new transmission service requiring those facilities.

Q. If BPA develops Incremental Cost Rates for all requests requiring service over a path subject to the Incremental Cost Rate, but not all the customers submitting the requests for that path agree to take the service, will BPA have to re-run the formula?

A. BPA will offer Incremental Cost Rate service only to those customers who have committed to take service at a given rate. BPA will establish a business practice that provides a mechanism, such as a customer commitment to take service at a given Incremental Cost Rate level prior to BPA offering service, to implement this.

Q. How will this proposal encourage the construction of new transmission facilities?

A. BPA believes that establishing a formula Incremental Cost Rate will facilitate setting initial Incremental Cost Rate charges because it will eliminate the need for a Northwest Power Act section 7(i) process each time one of several requests does not take service on an Incremental Rate Path. This will enable quicker decisions to proceed with new service and therefore promote new construction.

Q. Are there other ways the proposal will encourage construction?

A. Yes. Reducing the rate to reflect additional revenues received from additional uses of the facility subsequent to establishing the initial rate will encourage customers facing an initial Incremental Cost Rate to take service because of the prospect of future rate reductions.

BPA also believes the public process for presenting cost allocation proposals to customers will provide transparency about the reliability benefits and cost-causation of expansion of the transmission system. When combined with an Open Season approach to studying requests for transmission service and developing plans-of-service to meet the requests, our proposed Incremental Cost Rate offers a way to move projects forward when BPA determines that we cannot offer service at embedded costs rates.

Section 5: Consideration of Other Alternatives

Q. Has BPA considered other approaches to designing an incremental cost rate for NT service?

A. Yes. BPA has considered two other approaches. One is to apply the incremental cost rate to an NT Customer's entire Network Load. The other is a variation on the proposed Incremental Cost Rate. Under this variation, the NT Customer would pay the Incremental Cost Rate for the amount of capacity required for the new Network Resource or new Network Load, as under the BPA proposal, but that amount of capacity would be deducted from the Customer's Network Load billing factor each month for the NT Base Charge.

Q. Please explain how applying the Incremental Cost Rate to the NT Customer's entire Network Load would work.

A. One way would be to apply the "Or test" to the Customer's entire forecast Network Load. In that case, the annualized present worth of the Incremental Project Costs for the new Network Resource or new Network Load would be spread across the Customer's entire forecast Network Load and compared to the rate determined by adding the Incremental Project Costs to the NT embedded cost rate. The Customer would pay the higher of the two. The amortization period for this analysis would be the term length of the customer's service agreement.

Q. How would these other approaches affect other NT Customers?

A. Under the approach where the Incremental Project Costs are spread to the entire Network Load, when the NT Customer pays the Incremental Cost Rate, the embedded costs of the system used to serve the Customer are shifted to other NT Customers. Under the second approach that applies the NT Base Charge to the Network Load less the amount of demand for the new Network Resource or new Network Load, only the amount of demand for the new Network Resource or new Network Load would be subtracted from the Customer's Base Charge billing factor, thus reducing the NT billing determinant by that amount and spreading NT embedded costs over the remaining NT billing determinant.

Q. Are there other approaches that BPA is willing to consider?

A. Yes. This is the first rate case in which BPA has proposed an incremental cost rate. BPA encourages any party who is interested in this rate to submit testimony in support of any approach, including ones not mentioned in this testimony. BPA is willing to hold public meetings under the *ex parte* rule to discuss alternate approaches. Although BPA believes at this time that it is appropriate to propose an incremental cost rate in this rate case in order to process requests in its transmission queue, if BPA adopts an incremental cost rate in the record of decision in this case, BPA will continue to consider whether such adopted incremental cost rate can be improved. If so, BPA may propose improvements in a subsequent rate case.

Q. Does this conclude your testimony?

A. Yes.

BONNEVILLE POWER ADMINISTRATION

TRANSMISSION SERVICES

2010 INITIAL TRANSMISSION PROPOSAL

QUALIFICATION STATEMENTS

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QUALIFICATION STATEMENT OF

SARAH K. BERMEJO

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Sarah K. Bermejo. I am employed by the Bonneville Power Administration (BPA), Transmission Services, 7500 NE 41st Street, Suite 130, Vancouver, WA 98662.

Q. In what capacity are you employed?

A. I am the Transmission Rates Lead in the Transmission Policy and Strategy section of the Transmission Marketing and Sales group in BPA's Transmission Services.

Q. Please state your educational background.

A. I received a B.B.A. degree in Business Administration and Marketing from the University of Portland in June 1996. Additionally, I received a graduate certificate in Applied Energy Economics from Portland State University in August 2002.

Q. Please summarize your professional experience.

A. In May 1989, I began working for BPA as a student co-op for the Division of Resource Management where I was responsible for managing a training budget of $100,000. In June of 1993, I began working in Market Research & Assessment where I co-developed an electricity pricing model using multiple regression forecasting techniques and conducted market competitor analysis. In March of 1995, I transferred to Resource Optimization where I was responsible for operating the 30-day model of the federal hydro system and supporting staff with various statistical analyses. After graduating from college in June of 1996, I began employment with Bardsley & Neidhardt Marketing Research as a Project Manager where I initiated, developed and managed market research projects.

In August 2000, I returned to BPA and worked in the Transmission and Reserve Services Group covering many issues related to Ancillary and Reserve Services. I was primarily responsible for the development of Ancillary and Reserve service business strategy, revenue forecasting, and policy analysis within the BPA Control Area. I represented the BPA merchant function at the Northwest Power Pool (NWPP) Reserve Sharing Group and followed industry developments related to Ancillary and Reserve services at the Western Electricity Coordinating Council and North American Electric Reliability Council level for potential impacts to the NWPP Reserve Sharing Group, Control Area Operator Business Practices, and the relationship between BPA Power Services and BPA Transmission Services regarding generation inputs.

In May 2005, I became the Generation Inputs Study Manager responsible for coordinating both initial and final proposal study, documentation, and testimony for all inter-business line revenues and expenses for the 2007 Wholesale Power Rate Case. I also served as a witness for the Supplemental Power Rate Case for Reactive Power.

Currently, I am serving as the Lead Transmission Rate Case Process Manager responsible for overseeing all aspects of the BPA 2010 Rate Case for transmission and ancillary services.

Q. Please state your experience as a witness in previous proceedings.

A. I was a witness in the 2007 Wholesale Power Rate Case and the 2007 Supplemental Power Rate Case.

QUALIFICATION STATEMENT OF

DANNY L. CHEN

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Danny L. Chen. I am employed by the Bonneville Power Administration (BPA), Transmission Services, 7500 NE 41st Street, Suite 130, Vancouver, WA 98662.

Q. In what capacity are you employed?

A. I am a Public Utilities Specialist (Revenue Analyst) in the Transmission Policy and Strategy section of the Transmission Marketing and Sales group in BPA's Transmission Services.

Q. Please state your educational background.

A. I received a B.S. in Materials Science & Engineering from the University of California and a Post Baccalaureate in Accounting at Portland State University.

Q. Please summarize your professional experience.

A. In May 2005, I began working for BPA as a student co-op for Transmission Finance. As a student in Transmission Finance, I assisted senior staff in development of the OMB budget and analysis of the capital budget. In January 2006, I converted to full-time status as a Transmission Financial Analyst working on financial analysis and business case proposals for the capital program. In October 2006, I transferred to Asset Workload and Planning and continued to provide analytical support for the capital program. Since October 2007, I have worked as a Public Utilities Specialist (Revenue Analyst) in the Transmission Policy and Strategy organization of Transmission Marketing and Sales. My activities include revenue forecasting, revenue risk analysis, and analytical support to senior staff.

Q. Please state your experience as a witness in previous proceedings.

A. I have no experience in previous proceedings.

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QUALIFICATION STATEMENT OF

ARACELI C. CONTRERAS

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Araceli C. Contreras. I am employed by the Bonneville Power Administration, (BPA), Transmission Services, 7500 NE 41st Street, Suite 130, Vancouver, WA 98662.

Q. In what capacity are you employed?

A. I am a Program Analyst in the Transmission Policy and Strategy section of the Transmission Marketing and Sales group in BPA's Transmission Services.

Q. Please state your educational background.

A. I received a Bachelors of Art. in Psychology from the University of Washington in 1982 and a Masters in Public Administration from the University of Washington in 1987.

Q. Please summarize your professional experience.

A. I have worked for BPA since July 2002. From July 2002 to October 2006, I worked as a Program Analyst for Transmission Finance. My focus was Transmission revenue analysis and helping to produce the financial package for the Management Committee meetings. In October 2006, I transferred to Transmission Policy and Strategy, a section within Transmission Marketing and Sales. My responsibilities include producing forecasts for Point-to-Point Long-Term Revenue, Fiber & PCS Wireless, and some products of Other Revenues and Credits. These forecasts have been used for the 2010 Rate Case and other products such as Transmission Start-of-Year and Quarterly forecasts. In addition, I have worked on various revenue accounting issues.

Prior to working at BPA I worked for 13 years for the U.S. Government Accountability Office (GAO -- formerly called the U.S. General Accounting Office), the investigative arm of the U.S. Congress, where I conducted audits of various federal agencies. Most of my work at GAO consisted of performance audits relating to Natural Resource, Energy, and Computer System issues.

Q. *Please state your experience as a witness in previous proceedings.*

A. I have no experience in previous proceedings.

QUALIFICATION STATEMENT OF

REED C. DAVIS

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Reed C. Davis. I am employed by the Bonneville Power Administration (BPA), 905 NE 11th Avenue, Portland, OR 97232.

Q. In what capacity are you employed?

A. I am a Supervisory Public Utility Specialist in the Customer Services Load Forecasting and Analysis group.

Q. Please state your educational background.

A. I received a Bachelor of Science degree in Finance from Brigham Young University in 1979.

Q. Please summarize your professional experience.

A. In May of 1979, I began work in the rate department at Utah Power and Light as a rate statistician analyzing and forecasting electricity requirements for the utility with service territory in Utah, Idaho and Wyoming. I continued receiving additional responsibilities until I was made manager of the forecasting group. In January of 1989, I was hired into Pacific Power's Market Assessment Services group as the manager of the forecasting activity for the combined Pacific Power and Utah Power & Light companies following their merger. I retained the forecasting responsibilities while at Pacific Power as they transitioned through additional mergers until 2007. I was responsible for the analysis and forecasting activities for retail customers in Utah, Idaho, Wyoming, Oregon, Washington, California, and Montana. In October 2007, I was hired into my current position at Bonneville Power Administration (BPA), where I am responsible for the agency work in analyzing load and forecasting electricity requirements.

Q. Please state your experience as a witness in previous proceedings.

A. I have not been a witness in a BPA proceeding, previously. I have been a witness in rate cases in numerous jurisdictions in my previous positions on forecasting and weather normalization matters.

QUALIFICATION STATEMENT OF

EDISON G. ELIZEH

Witness for the Bonneville Power Administration

Q. *Please state your name, employer, and business address.*

A. My name is Edison G. Elizeh. I am employed by the Bonneville Power Administration (BPA), Transmission Services, 7500 NE 41st Street, Suite 130, Vancouver, WA 98662

Q. *In what capacity are you employed?*

A. I am the Manager of Transmission Rates and Revenue Forecasting in the Transmission Policy and Strategy section of BPA's Transmission Marketing and Sales group.

Q. *Please state your educational background.*

A. I graduated from the University of Nebraska – Lincoln in 1981 with a B.S. degree in Electrical Engineering.

Q. *Please summarize your professional experience.*

A. In May 2008 I began working for BPA, where I manage BPA's transmission rate design development. I participated in policy and business practice development for BPA's open access transmission tariff and the interconnection of wind generation. I also manage revenue forecasting for the transmission business unit.

Before joining BPA, I held multiple positions with Nevada Power Company from May 1981 through January 1993. I initially designed underground and overhead distribution lines for service to load. I eventually was promoted to Manager of Transmission Planning. In that position I developed a master transmission plan for the Nevada Test Site, the Yucca Mountain waste depository, and the Clark County Las Vegas metro area. In 1990, I was made Director of Wholesale Operations and Contracts. In that position I was responsible for transmission system operations and delivery of generation resources to load centers.

I worked for PacifiCorp from February 1993 to July 1997 and from May 2001 to May 2008. During my first four years with PacifiCorp I was responsible for the development and implementation of marketing and sales plans and customer support for the Arizona, California, Nevada, and New Mexico regions. I directed PacifiCorp's lobbying efforts with the Nevada legislature on the electric utility restructuring process and participated in the development of the California ISO protocols. From May 2001 through December 2003, I participated in the creation of RTO West. I was a member of the RTO West management team and participated in the creation and design of a market structure for the Northwest region. From January 2004 to May 2008, I managed the development of monitoring and correction tools to ensure that PacifiCorp's merchant function operated in compliance with FERC orders and that it met the standards of the North America Electric Reliability Council, the North America Electric Standards Board, and the Western Electricity Coordinating Council. I was also responsible for transmission system activities, including transmission requests and reservations, scheduling for load service, and merchant trading activities.

From August 1997 to December 2000 I worked for the Municipal Electric Authority of Georgia (MEAG). In that position I developed and managed planning, operations, and maintenance of the power delivery needs of 49 municipal members of MEAG. I managed the MEAG open access transmission tariff and it's OASIS. I was an executive member of the Southeast Regional Reliability Organization and the Southeast Security Coordinator, which managed the region's reliability.

Q. *Please state your experience as a witness in previous proceedings.*

A. I have not been a witness in any rate proceedings in previous professional positions.

QUALIFICATION STATEMENT OF

REBECCA E. FREDRICKSON

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Rebecca E. Fredrickson. I am employed by the Bonneville Power Administration (BPA), Transmission Services, 7500 NE 41st Street, Suite 130, Vancouver, WA 98662.

Q. In what capacity are you employed?

A. I am a Transmission Revenues and Rates Team Lead in the Transmission Policy and Strategy section of the Transmission Marketing and Sales group in BPA's Transmission Services.

Q. Please state your educational background.

A. I received a B.A. degree in Business Administration with an emphasis in Accounting from the Washington State University in 1989. Additionally, I received a Masters in Business and Administration from Marylhurst University in 2000.

Q. Please summarize your professional experience.

A. In June 2001, I began working for BPA as a rotational student for Corporate Finance. As a rotational student, my first placement was in Transmission Finance. In Transmission Finance I supported the development and management of the capital budget. In July 2002, I became a Transmission Financial Analyst. As a Financial Analyst, I was a key player in the development of the standards for managing the capital assets for Transmission and BPA. In addition, in coordination with other utilities, I assisted in developing Fiber installation and infrastructure financing models. In June 2004, I became a Senior Financial Analyst and was responsible for developing financial models that incorporated @Risk functionality and the Australian New Zealand risk model into BPA's business case process for our $300 million capital program.

I was BPA's lead for Transmission's Programs in Review (PIR) for 2004 and 2006. The PIR covered all of Transmissions expense and capital costs which were roughly $750 million and $300 million per year, respectively. As the lead in the PIR, I held the workshops and coordinated the development of the PIR costs and presentation material. I was also responsible for the internal and external PIR communications and for the closeout letter that set forth BPA's PIR decision.

In December 2007, I transferred to the Transmission Policy and Strategy group as the Transmission Revenues, Rates and Analysis Lead. In this position, I am responsible for leading the revenues team in the development and approval of Transmission revenues forecasts for rate cases and start-of-year (SOY) revenue forecasts. I coordinate and co-lead the development of the rates study, rates design, and other rates analysis. In addition, I am responsible for the coordination and leadership of the group in the financial analysis for the Network Open Season.

Q. Please state your experience as a witness in previous proceedings.

A. I have no experience in previous proceedings.

QUALIFICATION STATEMENT OF

DAVID L. GILMAN

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is David L. Gilman. I am a contractor for Bonneville Power Administration (BPA), Transmission Services, 7500 NE 41st Street, Suite 130, Vancouver, WA 98662.

Q. In what capacity are you employed?

A. I am an electrical engineer under contract to BPA in the Transmission Policy and Strategy section of the Transmission Marketing and Sales group in BPA's Transmission Services working primarily on Ancillary and Control Area Services rates and implementation.

Q. Please state your educational background.

A. I graduated from Oregon State University in 1969 with a B.S. degree in Electrical Engineering. I am a registered Professional Engineer in Oregon.

Q. Please summarize your professional experience.

A. I have worked for BPA since June 1968. I participated in several details in various areas of Engineering. From 1970 to 1973, I was assigned to the System Planning Section of System Engineering where I worked on various studies to determine adequacy of the BPA transmission system.

From 1974 to September 1994, I worked as an Electrical Engineer on the Advanced Planning Staff, Division of System Planning, Office of Engineering. I became a Senior Transmission Planning Engineer providing expert guidance for transmission planning and related economic analysis. My duties were: (1) studying long-range transmission requirements, including intertie and resource integration feasibility studies; and (2) studying and developing BPA's transmission rates, contracts, and policy.

Specific assignments have included segmentation development, wheeling loss assessment, and participation in the negotiation of wheeling contracts.

In September 1994, I was assigned to Strategic Planning and, in 1996, I was reassigned to the Business Strategy and Assessment group, where I performed the same function. My primary assignments were in the areas of transmission rates and contracts. Beginning in August 2000, I was assigned to the position of Ancillary Services Manager where I was responsible for the development and application of business practices for Ancillary and Control Area Services. The name of the group has since been changed to Transmission Policy and Strategy. I retired from this position in January 2008. I am currently employed under contract to work on similar issues.

Q. Please state your experience as a witness in previous proceedings.

A. I was a witness in the following BPA rate proceedings covering the topics identified: the segmentation of the Northern Intertie in the 1983 Rate Case; the Third AC Intertie Non-Federal Participation proceeding in 1992; transmission segmentation in the 1996 Rate Case; the segmentation for federal projects in the 2002 Power Rate Case; the Segmentation Study in the 2002 Transmission Rate Case; in the 2002 Proposed Revision to the ACS-02 Generation Imbalance Service Rate Case; and in the 2007 Power Rate Case for the segmentation of federal projects. In addition, I participated in the development of the 2009 Wind Integration Rate Case Proposal.

QUALIFICATION STATEMENT OF

RONALD J. HOMENICK

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Ronald J. Homenick. I am employed by the Bonneville Power Administration (BPA), 905 NE 11th Avenue, Portland, Oregon, 97232.

Q. In what capacity are you employed?

A. I am a financial analyst in the Analysis and Requirements group of Corporate Finance.

Q. Please state your educational background.

A. I received a Bachelor of Arts degree in English from Kent State University in 1973.

Q. Please summarize your professional experience.

A. From 1982 to 1985, I was employed as a Computer Programmer/Analyst for Electronic Data Systems under contract with BPA. In that capacity, I worked with the group that is now part of Financial Analysis & Requirements, designing and implementing numerous BPA revenue requirement/cost of service computer applications and performing various financial analyses related to BPA's 1983 and 1985 rate cases.

In 1984, I researched historical costs and performed various financial analyses that formed the financial basis of BPA's compliance report to the Federal Energy Regulatory Commission on separate accounting for power and transmission functions.

In 1985, I became a BPA employee and worked for the group that is now Financial Analysis & Requirements. I have been employed as a financial analyst since 1986. In this capacity, I have been responsible for various financial analyses related to revenue requirement development, such as preparation of the projected Federal Columbia River Power System investment base, depreciation forecasts, functionalization, and segmentation of the transmission revenue requirements.

I have been the primary analyst in Corporate Finance responsible for the annual preparation of the separate accounting analysis. I am also one of BPA's primary analysts in the area of repayment policy.

Q. Please state your experience as a witness in previous proceedings.

A. I have appeared as a witness on revenue requirement issues in BPA's 1991, 1993, 1995, and 1996 general rate proceedings, BPA's 3^{rd} AC Intertie Non-Federal Participation rate case, BPA's 2002 and 2007 wholesale power rate cases, and the 2002, 2004, 2006, and 2008 transmission rate cases.

QUALIFICATION STATEMENT OF

MARK A. JACKSON

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Mark A. Jackson. I am employed by the Bonneville Power Administration (BPA), Transmission Services, 7500 NE 41st Street, Suite 130, Vancouver, WA 98662.

Q. In what capacity are you employed?

A. I am a Senior Engineer in the Transmission Marketing Commercial Business Policy and Strategy group.

Q. Please state your educational background.

A. I have a B.S. Degree in Petroleum Engineering and a degree in Engineering Science from Montana Tech of the University of Montana, with additional course work in Energy Policy from PSU.

Q. Please summarize your professional experience.

A. I have 5 years experience with the Energy Department of the State of Montana as an Energy Policy Analyst, and 19 years experience as an engineer with BPA in various positions related to energy efficiency, renewable generation, distributed generation and Transmission policy, rates, and Tariff implementation. I have been in my current position as Senior Engineer with the Transmission Marketing Policy and Strategy group since 2001. I develop business policy for implementation through rates and business practices.

Q. Please state your experience as a witness in previous proceedings.

A. I have served as a subject matter expert for Ancillary Services related to Regulation and Frequency Response Service and wind-related balancing issues in the last general

Transmission rate case (FY2008-2009). I have also served as a subject matter expert for rate design in the WI-09 rate case.

QUALIFICATION STATEMENT OF

DANA M. JENSEN

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Dana M. Jensen. I am employed by the Bonneville Power Administration (BPA), 905 NE 11th Avenue, Portland, OR 97232.

Q. In what capacity are you employed?

A. I am a Financial Analyst in the Debt and Investment Management group in Corporate Finance.

Q. Please state your educational background.

A. I received an Associates degree in Humanities and General Studies from Lane Community College, Eugene, Oregon in 1987; a Bachelor of Science degree in Finance and Management from the University of Oregon in 1989; and a Master in Business Administration from Portland State University in 1995. My field of concentration was public finance.

Q. Please summarize your professional experience.

A. I am currently employed as a Financial Analyst at BPA. I provide economic and financial analytical support for rate cases, regulatory proceedings, access to capital and debt management planning. I serve as a senior technical analyst in developing cost, revenue, and financial forecasts and related analyses with the financial and operating condition of BPA, its business lines, customers, and competitors. I participate in preparing, analyzing, and implementing BPA's financial business strategy; measure financial performance against strategic goals; analyze industry and marketplace developments including potential State and Federal legislation that may affect BPA's future financial integrity; and develop and maintain financial data, forecast systems, and analytical tools.

In my previous position with BPA, I developed a credit review function to assess creditworthiness and determine credit limits for new customers (wholesale). I developed the procedures and a procedure manual, programmed rating criteria into our model, and developed a model to pull records from a data base program into Excel for manipulation and calculation and then to compile a user report. I performed credit analyses and review on potential hazardous waste contractors. I conducted ad hoc analysis including financial profiles, ratio analyses, net present value project analyses, revenue and profit forecasts, cost-effectiveness, buy vs. lease, and various other analyses. I developed current and pro forma business line financial statements and developed and used financial models (using Excel) to identify and assess the financial effects of alternative capital spending and expense levels and financing alternatives. I served as an in-house management consultant, performing studies on efficiency, cost analysis, and feasibility. I also assisted staff end-users in computer troubleshooting and loading software.

Prior to my employment with BPA, I worked for two years as a residential mortgage loan processor and substitute loan officer at a savings bank. I conducted extensive credit and financial analyses of the borrowers and builders, reviewing private and corporate (mainly sub S) financial statements and other records. I compiled summary reports based on my analyses for the underwriters and loan committee.

From September 1994 to October 1996, I was a Reserve Police Officer for the City of Hillsboro.

Q. *Have you ever been a witness in a rate case?*

A. Yes. I was on the revenue requirements panel in the 2002, 2007, and 2009 Power rate cases, and on the same panel in the 2004, 2006, and 2008 Transmission rate cases.

QUALIFICATION STATEMENT OF

ROBERT D. KING

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Robert D. King. I am employed by the Bonneville Power Administration (BPA), Transmission Services, 7500 NE 41st Street, Suite 130, Vancouver, WA 98662

Q. In what capacity are you employed?

A. I am an electrical engineer serving as the acting manager for the Transmission Policy and Strategy section of the Transmission Marketing and Sales group in BPA's Transmission Services. My position includes primarily responsibility for transmission marketing and sales policy development, business practices, rates, revenues, and new marketing tools.

Q. Please state your educational background.

A. I graduated from the University of Idaho in 1988 with a B.S. degree in Electrical Engineering.

Q. Please summarize your professional experience.

A. October 2008 – present. I am currently serving as the acting manager for Transmission Marketing and Sales, in the Transmission Policy and Strategy section.

April 2006 – October 2008. Served as the Transmission Regional Liaison Specialist for Transmission Services. My major duty was to develop a collaborative approach with BPA's regional customers to provide BPA with better tools to deal with internal flowgate congestion.

April 2004 - April 2006, Manager, Customer Service Planning and Engineering, Transmission Services, Bonneville Power Administration (BPA). As the Manager for Customer Service Planning and Engineering, I was in contact with professional groups, organizations, and FERC. I was responsible for providing workforce work plans, and supporting major Transmission Services efforts such as wind initiatives, Data Quality

Management, Joint Operating Committee, Sub Grid Management, and Research and Development. I also served as a member of the Transmission Services management team and helped to formulate key policies as well as being the decision-maker for long and short-range strategic planning in support of the overall Bonneville mission.

October 2002 - April 2004, Manager, Transmission Contracts, Strategy & Assessment, BPA. As the manager of Transmission Contract, Strategy & Assessment, I managed the development of business practices and policies. These policies included: managing the available transmission capacity for the BPA transmission grid, detailed directives on how to implement BPA's open access transmission tariff, coordinating development of proposed transmission rates for the upcoming rate case, managing the Slice transmission agreements, and forecasting transmission revenues. I also directed efforts to standardize contract offers and oversaw the development of a new contracts data base that linked available transmission capacity to transmission rights in contracts.

September 1994 - October 2002, Customer Account Executive, Transmission Services BPA. As a BPA Customer Account Executive, I was the principal representative for BPA with customers in Eastern Washington, Nothern Idaho, and all of Montana. I managed the BPA/customer business relationship, which included coordinating construction of new interconnections between BPA and customers.

Q. Please state your experience as a witness in previous proceedings.

A. This is the first time I have been a witness in a Rate Case proceeding.

QUALIFICATION STATEMENT OF

ALEXANDER LENNOX

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Alexander Lennox. I am employed by the Bonneville Power Administration (BPA), 905 NE 11th Avenue, Portland, OR 97232.

Q. In what capacity are your employed?

A. I am a Financial Analyst in the Analysis and Requirements group in Corporate Finance.

Q. Please state your educational background.

A. I received a Bachelor of Science degree in Political Science and History from University of South Dakota, in 1985, and Master of Arts degree in Political Science from the same institution in 1988. In 2000, I earned a Certificate in Public Management from the Atkinson School of Management, Willamette University.

Q. Please summarize your professional experience.

A. I joined BPA as a Financial Analyst in March 2004 to work on the BPA's revenue requirement. I am responsible for conducting research and analysis on a variety of financial issues related to the revenue requirement and to risk mitigation. I drafted portions of and coordinated development of the Revenue Requirement Study, Documentation, and Testimony of the 2006 and 2008 Transmission rate case and the 2007 and 2009 Supplemental Wholesale Power rate cases.

Before coming to BPA, I spent 16 years in the U.S. Army, state, and local government. Most recently, I worked at the Oregon Liquor Control Commission (OLCC) from 1995 to 2004. I was a Research Analyst in the Financial Services Division where I focused on revenue forecasting, trend analysis, legislative and policy analysis, and project management. While at the OLCC, I also served in a temporary capacity as the Director of Retail Store Operations and as the Administrative Services Manager.

Q. *Please state your experience as a witness in previous proceedings.*

A. I was a witness in the 2007 and 2009 Supplemental Power rate cases.

QUALIFICATION STATEMENT OF

BYRNE E. LOVELL

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Byrne Lovell. I am employed by the Bonneville Power Administration (BPA), 905 NE 11th Avenue, Portland, OR 97232.

Q. In what capacity are you employed?

A. I am employed as a Risk Analyst in BPA's Enterprise Risk Management group.

Q. Please state your educational background and professional qualifications.

A. I hold a Bachelor of Arts degree in Mathematics, which I received from Pomona College in 1974; a Master of Science degree in Counseling, which I received from the University of Oregon in 1980; and a Ph.D. in Systems Science (concentration: uncertainty), which I received from Portland State University in 1995.

Q. Please summarize your professional experience.

A. In 1984, I began working for BPA through a cooperative student program in the Resource Planning section of what was to become the Office of Energy Resources. I worked as an analyst and supervisor to develop and maintain mathematical models and perform analytical studies, (e.g., studies of the demand curve for Pacific Southwest market for nonfirm energy) for ten years. In June of 1994, I joined Finance as a Financial Analyst. In that position I was responsible for several aspects of financial risk management, including serving as the lead in the Financial Services Group for financial risk management activities in BPA's current general rate proceedings. I became responsible for the ToolKit (BPA's tool for calculating Treasury Payment Probability). In May 1997, I moved to a Policy Strategist position with BPA's Strategic Planning group. Along with the strategic planning work, my duties included continued support of BPA's risk analysis work, especially continuing to develop and run the ToolKit. I served as the senior staff analyst for BPA's probabilistic approach to analyzing fish funding, and for the non-operating risks in BPA's 1999 Power Rate Case. I am the author of the current version of The ToolKit and NORM (the Non-Operating Risk Model). My current duties involve helping design BPA's first Enterprise Risk Management program and implement it in conjunction with the Enterprise Risk Management Committee, and helping strengthen BPA's risk management programs across the Agency. My work continues to include supporting both the conceptual framework of BPA's TPP standard and work on developing the ToolKit and running TPP studies.

Q. Please state your experience as a witness in previous proceedings.

A. I appeared as a witness in BPA's 1995 and 1996 general rate proceedings, where I co-sponsored direct and rebuttal testimony on Revenue Requirement and Risk Analysis, as well as the Revenue Requirement Study and supporting documentation. I appeared again as a witness in the 2002 Power rate case, in both the original ("May 2000" proposal) and the modified proposal submitted to FERC (the "Supplemental Proposal"), and in the Safety-Net CRAC 7(i) process in early 2003. I worked on the risk analysis in the 2006 Transmission rate case. I was a witness in the 2007 Power rate case (WP-07) and in the 2007 Supplemental Power rate case (WP-07S), testifying on risk issues.

QUALIFICATION STATEMENT OF

BARTHOLOMEW A. McMANUS

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Bartholomew A. McManus. I am an employee for the Bonneville Power Administration, 5411 NE Hwy 99, Vancouver, WA 98666.

Q. In what capacity are you employed?

A. I am an Electrical Engineer in Technical Operations in charge of Automatic Generation Control (AGC).

Q. Please state your educational background.

A. I received a Bachelor of Science in Electrical Engineering (BSEE) from the University of Washington in 1993.

Q. Please summarize your professional experience.

A. I was hired by BPA in October, 1994. I was the programmer for the Automatic Generation Control (AGC) system for approximately nine years. In 2003, I moved to the Technical Operations section and took charge of AGC for BPA. In this position I insure our AGC system operates correctly with respect to national and regional standards. I have been involved with wind integration issues since 2006 and am the technical lead for transmission on our Wind Integration Team. I was a member of the Western Electricity Coordinating Council (WECC) Performance Work Group, North American Electric Reliability Corporation (NERC) Resources Subcommittee and the Northwest Power Pool (NWPP) from 2003 through 2007. I was a member of the WECC Control work group from 1995 through 2003, serving as chair from 1998 through 2003. I am also a member of multiple transmission operations-related taskforces and committees, including: WECC Operating Committee, WECC Technical Operations Subcommittee, the newly formed WECC Variable Generation Subcommittee and NWPP Operating Committee.

Q. Please state your experience as a witness in previous BPA proceedings.

A. I have not participated as a witness in previous BPA proceedings but did participate in the Wind Integration Rate case for 2009.

QUALIFICATION STATEMENT OF

RONALD E. MESSINGER

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Ronald E. Messinger. I am employed by the Bonneville Power Administration (BPA), Transmission Services, 7500 NE 41st Street, Vancouver, WA 98662.

Q. In what capacity are you employed?

A. I am currently an Electrical Engineer in the Commercial Business Assessment section of the Transmission Policy and Strategy group in the BPA's Transmission Marketing and Sales organization.

Q. Please state your educational background.

A. I graduated from Walla Walla College in 1988 with a B.S. degree in Engineering with an Electrical concentration. I am a licensed Professional Engineer in Washington State.

Q. Please summarize your professional experience.

A. I have worked for BPA since September 1988. From September 1988 until January 1995, I worked as a Design Engineer in BPA's Telecommunication Systems Branch. In January 1995, I joined BPA's Control Center Software Design group in BPA's System Operations Branch, where I supported Transmission Commercial Business Systems. In February 2003 I worked in Telecommunication systems maintenance before returning to the Control Center Software Design group in October 2003. In January 2004, I worked with a team developing a master plan for BPA's Transmission Business Commercial Systems. In May 2004, I was temporarily assigned to the Transmission Reservation Desk in BPA's Transmission Marketing and Sales organization. In February 2005, I worked for the Commercial Application Support group in BPA's Information Technology organization. In March 2006, I moved to the Database Design Group in BPA's

Information Technology organization where I continued to support Transmission Commercial Business Systems. Beginning September 2007, I joined the Transmission Policy and Strategy group, supporting Revenue Forecasting, including developing the Transmission Rate Study model, and supporting analysis of Ancillary Services such as Wind Integration and Balancing Area Reserves requirements.

Q. *Please state your experience as a witness in previous proceedings.*

A. I have not previously been a witness in a rate proceeding.

QUALIFICATION STATEMENT OF

TERRIN L. PEARSON

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Terrin L. Pearson. I am a contractor for Bonneville Power Administration (BPA), 7500 41st Street, Suite 130, Vancouver, WA 98662.

Q. In what capacity are you employed?

A. I am a contractor for Bonneville Power Administration's Policy Development and Analysis group in Transmission Services primarily working on FERC relations, conditional firm and rates.

Q. Please state your educational background.

A. I received a Bachelor of Science degree in Physics from the University of Washington in 1971. My fields of concentration were quantum physics and mathematics. I am a member of Phi Beta Kappa.

Q. Please summarize your professional experience.

A. In June of 1970, I began work at BPA in the Engineering Pool. In April of 1972, I completed the variety of assignments required in the pool and was placed in the Division of Power Supply. My first assignment was in the Hydrometeorology Section where I completed work on a stream flow forecasting computer model. While there, I also calculated Variable Energy Content Curves and Flood Control Elevations, and coordinated operations with the Reservoir Control Center at the Corps of Engineers. In November, 1980, I began working in the Operations Planning Branch where I was on the negotiating team for the Regional Act Power Sales Contract negotiations, represented BPA at the Centralia Owners' Meeting and the Trojan Fuels Subcommittee, and monitored compliance under the Computed Demand Contracts and the Service and

Exchange Agreements. I moved to the Power Scheduling Branch in July 1982. My principle duties in that group were to deal with the Pacific Northwest Coordination Agreement operational transactions and Hourly Coordination transactions. In addition, I provided scheduling procedures for contracts being negotiated. In March 1992, I moved to the Contracts Branch where I monitored studies of expected surpluses and deficits and made recommendations on economic actions to take to handle the surpluses and deficits. I was also Power Supply's Representative to the Direct Service Industries. In April, 1994, I moved to the Resource Optimization Branch as a technical team lead for the groups which handle the AOP and the DOP under the Canadian Treaty, the Pacific Northwest Coordination Agreement firm planning and operational scheduling and the 30-days and 90-days. I was selected for a detail to head the BPA Trading Floor in March of 1996. When the detail ended in September 1996, I went to the Mid-term Planning Group where I analyzed and made recommendations on handling surpluses and deficits associated with the Federal System generation. In June 1998, I came to Generation Scheduling to manage the training of new scheduler trainees and to negotiate and implement the new Slice product introduced by BPA. I came to the Transmission Business Line in 2003 and worked on the Conditional Firm Product, the Commercial Redispatch and Generation Reactive Self-Supply developments, and developing FERC relationships. I retired from BPA in March 2007 and returned to BPA as a contractor.

Q. Please state your experience as a witness in previous proceedings.

A. I was a witness in the following BPA rate proceedings covering the topics identified: the Slice Rate in the 2002 Power Rate Case; and the Reactive Supply and Voltage Control from Generation Sources Service in the 2007 Supplemental Rate Case.

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