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TESTIMONY of

BYRNE LOVELL, SIDNEY L. CONGER, JR., MARCUS A. HARRIS,

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Witnesses for Bonneville Power Administration

SUBJECT: POWER RISK ASSESSMENT AND MITIGATION **Page**

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SUBJECT: POWER RISK ASSESSMENT AND MITIGATION

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Byrne Lovell, and my qualifications are stated in BP-16-Q-BPA-26.

A. My name is Sidney L. Conger, Jr. and my qualifications are stated in BP-16-Q-BPA-10.

A. My name is Marcus A. Harris, and my qualifications are stated in BP-16-Q-BPA-15.

A. My name is Margo L. Kelly, and my qualifications are stated in BP-16-Q-BPA-21.

A. My name is Richard Z. (Zach) Mandell, and my qualifications are stated in BP-16-Q-BPA-29.

A. My name is Peter T. Williams, and my qualifications are stated in BP-16-Q-BPA-42.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor portions of the Power Risk and Market Price Study (Study), BP-16-E-BPA-04, and Power Risk and Market Price Study Documentation (Documentation), BP-16-E-BPA-04A. We also sponsor the portions of the General Rate Schedule Provisions (GRSPs), BP-16-E-BPA-09, concerning the Cost Recovery Adjustment Clause (CRAC), the Dividend Distribution Clause (DDC), and the National Marine Fisheries Federal Columbia River Power System Biological Opinion (NFB) Mechanisms. This testimony describes assumptions and analyses for quantitative and qualitative risks and BPA's resulting risk mitigation package as a whole. This testimony also describes notable changes in modeling, assumptions, and analysis between the BP-14 Final Studies and the BP-16 Initial Proposal. See Lovell et al., BP-14-E-BPA-15.

Section 2: Quantitative Risk Assessment

Section 2.1: Operating Risk Models

Section 2.1.1: Changes in Operating Risk Modeling Since the BP-14 Final Proposal

Q. Have you made any changes since the BP-14 Final Proposal to any of the Operating Risk Models that simulate risk data for direct input into RevSim?

A. Yes. Changes have been made to the computations in the Power Services (PS) Transmission and Ancillary Services Expense Risk Model since the BP-14 Final Proposal. The computations in BP-14 were found to overstate the amount of monthly firm PTP network transmission capacity that PS has available for secondary energy sales. The BP-14 analysis did not take into account 643 MW of capacity needed to deliver energy associated with the return of the Canadian Entitlement, and 20 MW of PS monthly firm PTP network transmission capacity needed to deliver energy to Big Horn County Electric Cooperative in Hardin, Montana. Big Horn is an out-of-region customer that signed a 20-year firm surplus power purchase agreement with PS in December of 1997. Overall, these changes increase PS transmission and ancillary services expenses because they lower the amount of firm take-or-pay capacity available before additional PTP network transmission capacity must be purchased when making secondary energy sales.

Q. Have there been any changes to RevSim since the BP-14 Final Proposal?

A. Yes. Changes have been made to RevSim since the BP-14 Final Proposal to account for the additional net revenue risk associated with the additional amounts of secondary energy that result from the forward power purchases of 22 aMW in FY 2016 and 100 aMW in FY 2017 to provide SE Idaho Load Service (SILS). While the SILS loads are included in the loads and the calculation of system augmentation in the Loads and Resources Study, BP-16-E-BPA-03, the amounts of these forward power purchases are not included as a resource. Once the amounts of the forward power purchases are used to provide SILS, the amounts of secondary energy marketable at Mid-C increase due to the reductions in firm load obligations associated with SILS. *See* Loads and Resources Study, BP-16-E-BPA-03, § 3.1.4 regarding the treatment of SILS forward power purchases, and Loads and Resources Study Documentation, BP-16-E-BPA-03A, Tables 1.2.1, 1.2.2, 1.2.3, lines 4-6 and Tables 4.1.1, 4.1.2, 4.1.3, line 6 where the SILS loads are embedded in the total load values.

Section 2.1.2: Federal Hydro Generation

Q. *Have you made any adjustments to the Federal hydro generation data in the Study and Documentation?*

A. Yes. Adjustments to Federal hydro generation have been made to Tables 3 and 4 of the Documentation to account for efficiency losses associated with standing ready to provide and deploy within-hour balancing reserves for both load and wind generation variability, and for carrying the spinning portion of the operating reserve obligation.

Q. *Why did you make hydro generation adjustments to Federal hydro generation for efficiency losses and incremental energy shift?*

A. Losses of efficiency and value occur as the system is set up to allow reserves to be deployed, and additional losses occur as the reserves are actually deployed. *See* Generation Inputs Study, BP-16-E-BPA-05, § 3. Hydro generation adjustments are made to account for this variable cost component, allowing BPA to appropriately allocate the cost of these losses to the parties that benefit from these reserve services.

Q. *Did you consider the Non-Treaty Storage Agreement in preparing the Study?*

A. Yes. A new Non-Treaty Storage Agreement with Canada was signed in April 2012. The effect of this agreement on Federal hydro generation is included in the Federal hydro generation data supplied to the risk assessment by the Loads and Resources Study, BP-16-E-BPA-03, section 3.1.2.

Section 2.1.3: PS Wind Generation

Q. *Did you make any changes to the output of the PNW Wind Generation Risk Model when estimating the PS wind generation used in RevSim?*

A. Yes. The PNW Wind Generation Risk Model considers wind projects that do not support BPA loads. Therefore, the output of the PNW Wind Generation Risk Model was scaled so that the average of the 3,200 iterations from the model is equal to the forecast amount of wind generation available to meet BPA loads.

Section 2.2: Development of the Net Secondary Revenue Forecast

Q. *Do you use median or mean net secondary revenues to calculate secondary energy revenues and balancing power purchases expenses?*

A. We are continuing to use median net secondary revenues to calculate the secondary energy revenues and balancing power purchases expenses input into RAM2016. This approach is consistent with the decision made in the BP-12 Final Record of Decision, which was continued in the BP-14 rate case.

Section 2.3: Non-Operating Risk Model

Q. Are there any risks previously modeled in NORM that you are no longer modeling?

A. Yes. The BiOp-related Court Ordered Spill risk has been removed due to adoption of the 2014 Supplemental BiOp. The VERBS revenue risk due to installed wind capacity has been removed due to decreased uncertainty in installed capacity. The revenue risk due to uncertain Operating Reserve requirements has been removed due to adoption of the new BAL-002 standard.

Q. Are there any risks in NORM that are new for the BP-16 rate proceeding?

A. Yes. Uncertainty in VERBS revenue due to sales of Operating Reserve capacity is now being modeled in NORM. The amount of *inc* capacity that PS will sell to TS during April through June of each year of the Rate Period is uncertain. PS selling more or less of this product than forecast would result in increased or decreased PS Net Revenue relative to forecast. *See* Study § 2.7.10.

Uncertainty in spill on the Lower Snake River during the spring of 2017 is also being modeled in NORM. Rate models assume that in the event of very poor water conditions in 2017, fish would be barged from the Lower Granite, Little Goose, and Lower Monumental dams. In this event, those dams would not be spilling for fish passage. NORM models the possibility that the Lower Snake dams would spill for fish passage in poor water conditions, which would result in decreased net secondary revenue in FY 2017.

Q. Have you changed any of NORM's risk models substantially?

A. Yes. We have changed how interest expense and appropriations expense risks are modeled in NORM. Instead of using subject matter experts' estimates of low, expected, and high interest rates for the variety of issuance dates and maturities in the model, interest rates are now built around historical changes in rates. By applying monthly changes in historical rates to a starting point (BPA's official forecast for FY 2015 rates), NORM generates monthly interest rates through the rate period for each point on the yield curve. Correlations between different Federal and non-Federal rates, as well as correlations between the different points on the yield curve, are inherent in the historical data set. Because of this, correlations do not need to be explicitly modeled. The methodology used is described in more detail in Study section 2.7.8.

Section 2.4: The Net Revenue-to-Cash (NRTC) Adjustment

Q. Have you made any notable changes to the NRTC Adjustments since the BP-14 rate proceeding?

A. No changes have been made to the methodology. We have changed the name of the adjustment from the Accrual-to-Cash (ATC) Adjustment to the Net Revenue-to-Cash Adjustment. This change was made in order to eliminate confusion between this adjustment and Available Transfer Capacity, which is also referred to as ATC.

Section 3: Quantitative Risk Mitigation

Section 3.1: Risk Mitigation Tools

Q. Have you made any changes to how reserves for risk are determined?

A. The general approach remains the same. Some categories of reserves not for risk are no longer needed and some new categories have been added:

1. REP Settlement funds no longer need to be excluded, as they were distributed in 2014.
2. $205 million in Power Prepay funds have been received from customers and are excluded from reserves for risk.

3. $15 million in customer deposits for credit worthiness have been received and are excluded from reserves for risk.
4. $6 million in deposits from third parties for cost-sharing of fish and wildlife projects are excluded from reserves for risk.

Q. Have you made any changes to the Treasury Facility or how it is attributed between business lines?

A. No. We are still proposing that all $750 of the Treasury Facility be attributed to PS risk for ratesetting purposes. Note that this attribution is made in order to test the sufficiency of PS's rates to meet the TPP standard; the attribution does not imply "ownership" or reservation of the Treasury Facility for actual use during the rate period.

Q. Have you made any changes to the Liquidity Reserve Level?

A. No. We propose that the liquidity reserve level remain at $320 million.

Section 3.2: The Cost Recovery Adjustment Clause (CRAC) and Dividend Distribution Clause (DDC)

Q Have you proposed any changes to the CRAC or DDC mechanisms?

A. Yes, we propose that the Thresholds for the CRAC and DDC be set based on Accumulated *Calibrated* Net Revenue (ACNR), rather than Accumulated Net Revenue (ANR).

Q. What is the difference between ANR and ACNR?

A. ANR is the sum of the annual net revenue calculations for Power Services since the end of FY 2014. ACNR is the same calculation, adjusted to exclude certain debt management, contract-related, and other transactions that affect the relationship between accruals and cash.

Q. Why are you "calibrating" Accumulated Net Revenue (ANR)?

A. The objective of calibrating ANR is to reduce the risk that the accrual metric BPA uses for determining whether the CRAC or DDC has triggered will become less well correlated to financial reserves available for risk. BPA's ability to pay the U.S. Treasury, and thus TPP, depend on these reserves.

Most financial events pose no threat to the correlation between net revenue and cash flow. For example, a change in net secondary revenue will change both net revenue and cash flow by very similar amounts; a change in interest expense will also affect net revenue and cash flow by very similar amounts.

However, many other kinds of financial events can erode the correlation. While a change in Energy Northwest (EN) debt service will affect both net revenue and cash flow, a change in repayment of Federal debt principal will affect only cash flow, thereby altering the relationship between net revenue and cash flow. Thus, a financial transaction that involves changing EN debt service and Federal principal repayment in equal but oppositely-signed amounts will have no effect on cash flow, but will create a change in net revenue.

Q. Do you expect any calibrations to occur during the rate period?

A. Yes. We expect there will be calibrations, but we do not know their amounts. The anticipated refinancing of Energy Northwest regional cooperation debt in 2015 and 2016 (*see* Lennox *et al*., BP-16-E-BPA-13, § 5) will increase power net revenues, but not cash (compared to the amounts assumed in this Study). There may be other, unanticipated events that require calibration.

Q. *Why do you use ACNR instead of using ANR and incorporating these adjustments now, as if known, in your calculation of the CRAC and DDC thresholds?*

A. The debt transactions mentioned above are very likely to occur, and the amounts of the needed adjustments are likely to match what we would forecast now. Therefore, those transactions could be incorporated into ANR-based CRAC and DDC thresholds without having a mechanism to adjust the relationship between cash and net revenue after BP-16 rates are set. However, doing so would not allow us to adjust the relationship between NR and cash flow for other, currently unknown, debt- or contract-related or other transactions, nor would it allow us to adjust for differences in the size of the adjustments of the anticipated transactions or to exclude the adjustments in circumstances where the anticipated transactions do not occur.

During the BP-14 rate period, the relationship between cash and ANR deviated by $378 million due to Regional Cooperation Debt transactions during FY 2014. These transactions, which were not anticipated during the BP-14 rate proceeding, broke the relationship between cash and ANR that was reflected in the CRAC and DDC thresholds. We are proposing the ACNR methodology instead of a fixed adjustment in order to prevent these types of unanticipated deviations, which could cause the CRAC to over-collect or under-collect or the DDC to distribute more or less than it should from a liquidity perspective.

Q. *Did you consider other ways to adjust the CRAC and DDC calculations for events having different impacts on net revenue and cash flow?*

A. Yes. The calibration could be applied to the CRAC and DDC thresholds instead of to calculations of net revenue. We are proposing to compare a calibrated net revenue figure to the CRAC and DDC thresholds, but we could compare a net revenue figure to calibrated CRAC and DDC thresholds. The required calculations would be virtually identical and the results would be identical.

Q. Are you proposing any other changes to the CRAC or DDC?

A. No.

Section 3.3: Planned Net Revenue for Risk (PNRR)

Q. Are you proposing any PNRR for the Rate Period?

A. No.

Section 3.4: The ToolKit Model

Q. Have you made any major changes to the ToolKit and how it calculates TPP?

A. No.

Section 4: Qualitative Risk Assessment and Mitigation

Section 4.1: BiOp Litigation Risks and the NFB Mechanisms

Q. Have you made any changes to how you model the NFB Mechanisms?

A. Yes. In BP-14 we modeled the risk of BiOp-related Court Ordered Spill in NORM, and calculated that risk's effect on the CRAC. We are not quantitatively modeling this risk in the BP-16 Initial Proposal due to the adoption of the 2014 Supplemental BiOp. While the modeling of the risk has been removed, the risk of a BiOp-related court order is still covered under the NFB mechanisms.

Q. Have you made any changes to the NFB mechanisms?

A. Yes. The first trigger event has been modified. *See* Study § 4.2; 2016 Power Rate Schedules, BP-16-E-BPA-09, GRSP II.N. We added the U.S. Fish and Wildlife Service as an entity that could issue an FCRPS BiOp. Prior to this, only the National Marine Fisheries Service was specified as an entity that could issue an FCRPS BiOp.

Q. *Are there other Biological Opinions that could affect BPA's fish and wildlife costs in the FY 2016–2017 rate period?*

A. Yes. A BiOp was issued for the Willamette Valley Projects of the FCRPS in July 2008, but it is not currently being litigated. The BiOp for the Libby Project was litigated, but the litigation was settled. BPA could experience unanticipated costs stemming from either of these BiOps, or litigation over them, or from other BiOps.

Q. *Would future litigation over either of these BiOps be covered under the NFB Mechanisms?*

A. Yes. Costs (including foregone revenue) that are not anticipated in BP-16 arising from either of these two BiOps or from new BiOps, or from litigation over these BiOps or new BiOps, would be covered.

Section 4.2: Tier 2 Risks

Q. *Are there risks associated with service at Tier 2 rates that you have not been able to mitigate?*

A. No. The terms and conditions for service at Tier 2 rates will adequately mitigate those risks. Our analysis is described in section 4.3 of the Study.

Section 4.3: Resource Support Services (RSS) Risks

Q. *Are there risks associated with RSS that you have not been able to mitigate?*

A. No. The terms and conditions for RSS will adequately mitigate those risks. Our analysis is described in section 4.4 of the Study.

Section 5: Possible Changes in the Final Proposal

Section 5.1: Possible Changes to Quantitative Risk Assessment and Mitigation

Q. Might some of the data on which the risk assessment and risk mitigation are based change by the Final Proposal?

A. Yes. In fact, nearly all of the data underlying our risk modeling, and thus the results of the assessment and mitigation, are likely to be updated, such as gas prices, electricity prices, and forecasts of installed capacity of wind generation. Changes to any of these data can affect the TPP calculations. Perhaps the most important update in terms of calculating TPP is the forecast of FY 2015 Net Revenue, where updated forecasts of FY 2015 net secondary revenue are the most significant component. In the Initial Proposal, PS faces one whole year of NR uncertainty. TPP for FY 2016–2017 is assessed by examining the distributions of ending reserves and liquidity tool balances for FY 2016 and FY 2017. Each distribution of year-end results depends on simulated events in that year and on the year-end distribution from the previous year. Thus, the ending FY 2016 distribution depends critically on the ending FY 2015 distribution as well as on events during FY 2016.

Q. How will NORM be updated for the Final Proposal?

A. We will update the costs and revenues for FY 2015 to be consistent with BPA's most recent Quarterly Review, typically the Second Quarter Review. The subject matter experts we consulted indicated that the uncertainty around revenues or expenses modeled in NORM needs to be updated. If a second Integrated Program Review process is held, we will update FY 2016–2017 expenses and revenues consistent with any changes made to the FY 2016 and FY 2017 revenue requirement. We may also model uncertainties around additional costs or revenues that emerge as a result of this rate proceeding.

The CGS Outage Duration risk module will be updated if BPA receives significant new information from Energy Northwest on the length of the refueling outages in FY 2015 or FY 2017. The CGS Outage Duration risk will also be updated with the current market price forecast.

Q. Are there any possible changes to PNRR or the CRAC in the Final Proposal?

A. Yes. If mid-year FY 2015 Net Revenue results are especially bad, and BPA needs to make changes to increase TPP, BPA may add PNRR and/or modify the CRAC in order to meet the 95 percent TPP standard.

Q. What changes might be made in the Final Proposal with respect to the Net Revenue-to-Cash adjustments?

A. The most likely adjustments could arise from changes to the Energy Northwest FY 2016 and FY 2017 budget affecting the Energy Northwest pre-paid expense adjustment; changes in Federal debt amortization; changes to non-cash items, including depreciation and amortization; and changes in expenses, revenues, and cash resulting from transactions entered into between the time of the Initial Proposal and the Final Proposal.

Q. Might there be changes to how you assess quantitative risks in the Final Proposal?

A. Yes. The ToolKit we use in this Initial Proposal is written in Excel® and Visual Basic for Applications. The model has been rewritten in R, an open-source statistical programming language, which uses a web-based front end for running the model and viewing results. When our validation testing is complete, we will start using the R-based ToolKit instead of the Excel-VBA version. The new version ToolKit still uses the same inputs and calculation method as the version used in BP-14. While the method of interacting with the ToolKit is different, what the ToolKit does is the same. Using the web interface, users will be able to modify the input parameters, select different NORM and RiskMeasures files to run, and run the model. After running the model, ToolKit will show results in the web interface. These results include the same key summary statistics and 3,200 games of data that the current version produces. These results will exportable to Excel or other tools for further analysis.

Section 5.2: Possible Changes to Qualitative Risk Assessment and Mitigation

Q. Are there changes you might make to the NFB Mechanisms in the Final Proposal?

A. There are no NFB Mechanism changes that we anticipate making in the Final Proposal.

Q. Are there changes you might make in the Final Proposal in the assessment or mitigation of risk associated with service at Tier 2 rates or RSS?

A. There are no such changes that we now anticipate making in the Final Proposal. We will, of course, respond to issues raised by parties in their direct cases.

Q. Are there changes you might make in subsequent rate cases in the risks or risk mitigation for RSS or Tier 2?

A. BPA reserves for future rate cases the potential of assigning to its Tier 2 Rate service the costs of a variable energy resource or a forward purchase made for only part of the year, or not making any forward purchases at all. If BPA makes such a cost assignment in the future, it will employ a pricing approach comparable to that which is used for the Diurnal Flattening Service and Resource Shaping Charge. Such an approach would convert the value of those purchases into a flat amount across the year. The risks associated with this type of scenario could be different from those in the FY 2016–2017 rate period and will be evaluated separately if they arise in the future. If evidence emerges from either BPA sources or other parties that the financial risks associated with RSS are substantial, BPA will consider other approaches to treating these risks, possibly including efforts to quantify the financial impacts of the risks.

Q. Does this conclude your testimony?

A. Yes.

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