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TESTIMONY of

GAIL A. HAMMER and PETER T. WILLIAMS

Witnesses for Bonneville Power Administration

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SUBJECT: Market Price and Natural Gas Price Forecasts

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Gail A. Hammer, and my qualifications are contained in BP-16-Q-BPA-14.

A. My name is Peter T. Williams, and my qualifications are contained 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 and Documentation. *See* Power Risk and Market Price Study, BP-16-E-BPA-04, § 2.3-2.4 (Study); Documentation, BP-16-E-BPA-04A. Our testimony also addresses modeling changes to, and assumptions regarding, BPA's market price and natural gas price forecasts.

Section 2: Market Price Forecast

Q. Please describe the content and purpose of the market price forecast.

A. The market price forecast comprises two forecasts of Mid-Columbia (Mid-C) spot market prices. Each forecast, in turn, comprises a distribution of 3,200 monthly diurnal market price forecasts for the duration of the BP-16 rate period, FY 2016–2017. The first forecast asssumes that hydro conditions are drawn randomly from 80 historical water years. The second forecast—the "critical water forecast"—uses water conditions from 1937 for each of the 3,200 forecasts. The 80-water-year forecast is used to value secondary energy sales, and to determine the Priority Firm load shaping rate, among other uses. *See* Study, § 1.1.2. The critical water forecast is used to value the cost of system augmentation. *Id*. § 2.6.2.

Q. Please describe the methodology used to produce the market price forecasts.

A. As in previous rate filings, we use the AURORAxmp® production cost model to forecast spot market energy prices. For each forecast, AURORAxmp® is run 3,200 times, with each instance using inputs chosen at random from distributions of inputs that reflect risk in: WECC-wide loads; PNW, California, and British Columbia hydro generation; hourly regional wind generation; monthly CGS output; hourly path ratings on three different PNW interties; and monthly Henry Hub natural gas prices.

Q. Please describe AURORAxmp® and explain why BPA uses it in rate proceedings.

A. AURORAxmp® is a production cost model. Given the model inputs, it dispatches generating units to meet load with the objective of meeting systemwide load at the minimum cost. Subject to various operating constraints, the solution yields generator output and costs, and transmission line utilization. Given the solution, the market price is evaluated as the cost of delivering an additional unit of energy to a given hub, including losses and wheeling.

AURORAxmp® is a widely used, reliable, and transparent tool used by hundreds of clients globally to forecast energy prices. Forecasts produced by AURORAxmp® have consistently provided reasonable valuations of secondary energy revenue for BPA.

Q. Please list any changes that have been made to the market price forecast risk models and describe their purpose.

A. We made changes to three risk models used to inform the market price forecast: a new wind risk model is used to generate hourly synthetic wind profiles; a new transmission risk model is used to simulate hourly path ratings for the AC, DC, and BC interties; and a change was made to the way in which inter-regional hydroelectric generation is conditionally modeled to more accurately reflect inter-regional hydrology.

Q. Why did you adopt a new wind risk model?

A. The new wind risk model, much like the previous model, generates hourly profiles of synthetic wind generation using historical data. However, it uses a Markov Chain Monte Carlo rejection sampling algorithm rather than the nearest-neighbor algorithm used in the previous model. The new algorithm ensures that the aritificial wind series will embody all of the statistical properties of the observed wind generation data, and does so using a more efficient sampling algorithm. Like the previous model, it captures hourly, monthly, and annual uncertainty in wind generation patterns. The effect of the new wind risk model on market prices is very small.

Q. Why did you adopt a new transmission risk model?

A. The new transmission risk model uses observed path ratings on the AC, DC, and BC interties to generate synthetic profiles of transmission line outages that are consistent with path outages in both duration and magnitude. The methodology uses a Markov Chain transition matrix and simple bootstrap to generate the artificial time series. The decision to rewrite the model itself was a by-product of recalibrating the previous model. We developed a more efficient method for simulating transmission risk. As with the new wind risk model, the change in transmission risk modeling does not have an appreciable effect on market prices.

Q. Why did you change the hydroelectric generation modeling?

A. The change to modeling hydroelectric generation on an inter-regional basis was made for two reasons. First, we had concerns that some historical data for both California and British Columbia hydroelectric generation were not useful for statistical analysis. Different sources for the data and different methodologies for converting the data into hydro generation ratios for use in AURORAxmp® resulted in some anomalies that rendered the data questionable. As a result of this observation, for sampling purposes we now limit the historical record to years for which a consistent data source and

methodology are available. Therefore, 1977–2008 is used for British Columbia and 1970–2008 for California.

Second, analysis performed by BPA staff revealed that hydroelectric generation in the three basins (California, British Columbia, and the Pacific Northwest) is statistically independent. That is, independence between each of the basins should be preserved in modeling their respective generation. As such, the water-years chosen for British Columbia and California are each conditionally independent of the water-year chosen for the PNW.

Q. Have you made any other changes to models and assumptions?

A. Yes. We allow the dispatch cost of wind to be negative. Negative prices at the Mid-Columbia hub have become a regular phenomenon. Because we understand the forces driving the sub-zero prices, we decided it was appropriate to model them in our analysis of spot market Mid-C prices. However, consistent with BPA's policy not to bid negative prices, the revenue simulation component of the rate case assumes a lower bound of zero on the balancing transaction price.

We assigned negative variable costs to wind generators in the region using a regression-based representation of the opportunity cost of displacing wind as a function of total MW. The data for the regression are the curtailment quantities and associated costs from 2012 oversupply events. We then assigned costs to wind plants in AURORAxmp® using that regression in no particular order.

Q. Please describe the methodology used to determine new resource additions in AURORAxmp®.

A. For BP-16, We used two sources of data to determine resource additions in the WECC. *See* Study, § 2.3.7. First, data from a third-party consultant, which relied in part on WECC's Transmission Expansion Planning Policy Committee data, determined renewable resource additions. Renewable resource additions comprise both planned and

sited facilities, as well as generic additions sufficient to meet state level renewable portfolio standards. These resources were included in the resource table of AURORAxmp®. Second, the capacity expansions mode of AURORAxmp® was used to determine all economically profitable thermal additions, again WECC-wide. We determined that no resources other than those currently under construction would be added to the PNW during the applicable rate period. Further, default AURORAxmp® data for new resource costs were used. The thermal resource additions determined to be profitable were then included in the AURORAxmp® rate case price forecast studies.

Q. Were there any other changes to AURORAxmp® for BP-16?

A. Yes. We currently run AURORAxmp® version 11.5.1001 and North American database version 2014-02, which are updated versions of the model and data base used in the BP-14 rate case. There were no major logic changes to the model.

Q. Do you anticipate any changes to AURORAxmp® or its inputs between now and the Final Proposal?

A. Yes. We anticipate version and database upgrades. We also anticipate recalibrating any risk models should new data be made available. Should a new forecast be provided, it will also serve as input to AURORAxmp® for the Final Proposal.

Q. Do you model carbon prices in California?

A. No. Carbon prices have real impacts on prices in California markets, but through the lens of a production cost model, the impact on Mid-Columbia prices is negligible. California treats all imported power as originating from an unspecified resource with an emissions rate of 1100 lb/MWh. To capture this in AURORAxmp®, we impose a wheeling adder equivalent to that cost, given the price of a carbon allowance in California. This results in two competing effects: higher prices in California encourage PNW exports, which results in higher prices in the PNW; and the wheeling adder makes it more costly to export power to California. The net effect is a negligible change in average export

patterns, and hence a negligible impact on Mid-C prices. BPA occasionally sells power at a preferential rate as an Asset Controlling Supplier, which implies that the transaction is not subject to carbon allowance requirements and, therefore, BPA would realize a higher sales price. However, AURORAxmp® cannot distinguish between sources of power, and is incapable of quantifying these transactions.

Section 3: Natural Gas Price Forecast

Q. How is the natural gas price forecast used?

A. The natural gas price forecast is used to provide monthly natural gas prices that are input into the Natural Gas Price Risk Model. *See* Study, § 2.3.1.5.

Q. Is the natural gas price forecast used in a deterministic manner in AURORAxmp®?

A. No. The natural gas price forecast is reflected in the electricity market price forecast only through providing median monthly prices of the natural gas price risk distribution used when AURORAxmp® runs 3,200 games for both the market price run and the critical water run.

Q. Does the natural gas price forecast represent the most likely future natural gas prices?

A. No. The natural gas price forecast represents values that reflect a given conditional probability, rather than the most likely future natural gas prices. That is, for median prices, there is a 50 percent probability that prices will be lower than the forecast, and a 50 percent probability that prices will be higher than the forecast, given the information available today.

Q. Are there any possible changes in information between now and the Final Proposal that could result in a decrease to the natural gas price forecast?

A. Low-cost natural gas production continues to change the natural gas landscape. If demand for natural gas does not grow at the expected rate due to further delays in industrial projects or lack of gas-fired generation load, supply growth has the potential to

outpace demand growth and lead to another period of low natural gas prices, such as in 2012 when prices fell below $3.00/MMBtu. If oil production continues to increase at the current rate regardless of the recent decline in the price of oil, additional low-cost associated natural gas supply resulting from oil drilling would also be a cause for a downward revision to our forecast. With new pipeline infrastructure and processing capacity coming on line in the Northeast region, there is the potential for a larger-than-expected flow of natural gas out of the Appalachian Basin. A major advance in production technology could further decrease the cost of exploration, drilling, and well stimulation and place additional downward pressure on the marginal cost of gas.

Q. Are there any possible changes in information between now and the Final Proposal that could result in an increase to the natural gas price forecast?

A. An upside in prices could be seen if natural gas demand for electric generation to replace coal-fired power plant retirements is greater than expected upon the effective date of the Mercury and Air Toxics Standards in April 2015. A higher price forecast for FY 2016–2017 could also be seen if policy or legislative action is taken that would increase the cost of producing or transporting natural gas. Proposals have been made at the national and state levels that may impact the price of or access to natural gas. Additionally, proposed and approved EPA regulations may increase the demand for natural gas.

The evolution of production growth combined with new processing and pipeline infrastructure throughout North America may also necessitate a change to monthly basis differentials in the region as the traditional pipeline flow of gas is transformed.

A definitive step toward any of the above factors could provide a basis for adjusting the natural gas price forecast in the Final Proposal.

Q. Would a change to the natural gas price forecast in the Final Proposal imply that the Natural Gas Price Risk Model did not accurately capture natural gas price risk in the Initial Proposal?

A. No. The Natural Gas Price Risk Model does not estimate the center of the natural gas price risk distribution. Rather, the model is used to estimate variability around the deterministic forecast prices, which are subject to change based on shifts in market fundamentals. *See* Study, § 2.3.1.5.

Section 4: Natural Gas Price Risk

Q. Why do you include natural gas price risk in your analysis of electricity market prices?

A. Because the price of natural gas has a direct impact on the price of electricity for much of the year, variability in the price of natural gas has a direct impact on the variability of electricity prices. In this sense, uncertainty regarding natural gas prices is a direct source of net secondary revenue risk, and hence risk of cost recovery when setting rates. *See* Study, § 2.3.1.5.

Q. Have you made any changes to the Natural Gas Price Risk Model or data used to calibrate the model since BP-14?

A. No changes have been made to the Natural Gas Price Risk Model; however, data has been updated to include daily historical Henry Hub nominal prices from January 1, 2009, to June 30, 2014. In BP-14 we used daily historical Henry Hub nominal prices from January 1, 2009, to June 30, 2012.

Q. Is an autoregressive model appropriate for simulating natural gas prices?

A. Yes. An autoregressive process is a concise way to model a time series variable with a given serial relationship. That is, when we expect subsequent observations of a random variable to be closely related through time, an autoregressive model summarizes the data very efficiently. It also provides a flexible framework for simulating future price

streams. With the parameters from the initial model, simulation of future prices is a simple matter of extrapolation.

Q. What are the results from the natural gas price risk model?

A. Monthly results from the natural gas price risk model are shown in Table 2 in the Study for the 5th, 50th, and 95th percentiles.

Q. Does this conclude your testimony?

A. Yes.

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