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TESTIMONY OF

ERIC W. GRAESSLEY, ALLEGRA J. HODGES,

JAMES H. VANDEN BOS, AND PETER T. WILLIAMS

Witnesses for Bonneville Power Administration

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Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Eric W. Graessley, and my qualifications are contained in BP-18-Q-BPA-13.

A. My name is Allegra J. Hodges, and my qualifications are contained in BP-18-Q-BPA-17.

A. My name is James H. Vanden Bos, and my qualifications are contained in BP-18-Q-BPA-40.

A. My name is Peter T. Williams, and my qualifications are contained in BP-18-Q-BPA-42.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor portions of the Power Market Price Study and Documentation, BP-18-E-BPA-04 (Study). Our testimony also addresses modeling changes to and assumptions regarding BPA's market price and natural gas price forecasts.

Q. In recent rate cases the Power Market Price Study has been combined with the Power Risk Study. Is that still the case?

A. No. For the BP-18 rate case the Power Market Price Study and Documentation (BP-18-E-BPA-04) has been separated from the Power Risk Study and the latter is combined with the Transmission Risk Study (*see* BP-18-E-BPA-05).

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-18 rate period, FY 2018–2019. One forecast assumes that hydro conditions are drawn randomly from 80 historical water years. The other forecast—the "critical water forecast"—uses water conditions from the year 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 Power (PF) Load Shaping rate, among other uses. *See* Study § 1.2. The critical water forecast is used to value the cost of system augmentation. Power and Transmission Risk Study, BP-18-E-BPA-05, § 3.1.2.1.1.

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

A. As in previous rate proposals, we have used 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; Pacific Northwest (PNW), California, and British Columbia hydro generation; hourly regional wind generation; monthly Columbia Generating Station (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 system-wide 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 relied on by hundreds of clients globally to forecast energy prices. As such, forecasts produced by AURORAxmp® provide for a reasonable projection of secondary energy revenue for BPA.

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

A. Yes. First, we have allowed the dispatch cost of renewable generation to be negative. Second, we altered the dispatch cost of hydro to allow for limited hydro energy curtailments. Third, we adjusted the hydro shaping factors in the PNW to counteract diurnal flattening. Fourth, we updated the composition of generic renewable additions in California. Fifth, we included mechanisms to reflect California's carbon pricing. These changes are explained below.

Q. Why have you allowed the dispatch cost of renewables to be negative?

A. Because negative prices have become a regular phenomenon at the Mid-Columbia hub and throughout California, and because we understand the forces driving negative prices, we decided it was appropriate to model negative prices in our analysis of spot market 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.

Q. How do you justify the assumptions used to establish negative dispatch costs of wind and solar resources?

A. We anchored the dispatch cost of wind to the Federal production tax credit (-$23/MWh) because it is both transparent and widely available. In reality, alternative sources of income vary tremendously across time and location for wind resources. Given the

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A. We anchored the dispatch cost of wind to the Federal production tax credit (-$23/MWh) because it is both transparent and widely available. In reality, alternative sources of income vary tremendously across time and location for wind resources. Given the

opaque nature of these arrangements and a corresponding lack of a consistent methodology to replicate and verify such variation throughout the Western Interconnection, a flat dispatch cost is a reasonable proxy for all wind resources' dispatch cost for the BP-18 rate period. Additionally, when spot market prices have been negative over the last three years in California, they have averaged between about -$20/MWh and -$30/MWh. Furthermore, analysis of day-ahead bids in California's market made publicly available by the California Independent System Operator (CAISO) indicates the bulk of subzero bids occurring in the -$10/MWh to -$30/MWh range. While the -$23/MWh estimate may overstate negative dispatch costs of some wind resources, it also understates negative dispatch costs of many wind resources with power purchase agreements well above $23/MWh, as well as largely ignoring the substantial and growing cluster of bids at -$150/MWh in California's day-ahead market. Without better information as to which misrepresentation is more frequent on a locational basis, we believe using a single-level estimate is a reasonable approximation to model the negative price phenomenon. Lacking a widely available and transparent supplemental income figure for solar resources analogous to the Federal production tax credit for wind resources, we rely on the AURORAxmp® default spread between wind and solar resource dispatch costs.

Q. Why did you alter the dispatch cost of hydro generation?

A. If we kept the default dispatch cost, all hydro generation in a particular zone would have to be curtailed (spilled) before any wind or solar resources. Conversely, if we set the dispatch cost of all hydro generation just below that of wind, no hydro generation would be spilled before wind or solar resources. Neither approach provides a satisfactory representation of real-world system dispatch. To address this issue, we estimated the amount of hydro generation that may be spilled, retained the AURORAxmp® default

hydro dispatch cost for this portion of hydro energy, and set the dispatch cost of all remaining hydro energy to -$24/MWh, just below that of wind resources. These assumptions ensure that, when applicable, modeled amounts of spillable hydro generation are curtailed first. As the system moves down the resource supply stack, renewable resources are curtailed and zonal prices become negative; finally, the remaining hydro generation and any must-run resources would be curtailed.

Q. Why did you change the hydro shaping factor?

A. The technique we employed to set aside a portion of hydro energy to be available for spilling required this generation to have a flat diurnal shape. The amounts of spillable hydro generation tend to be substantial relative to overall regional hydro generation. The result is that the ratio of heavy load hour (HLH) to light load hour (LLH) hydro generation is distorted to levels significantly below historical observations and expected system operations, causing inappropriate HLH price increases and LLH price decreases. Altering the hydro shaping factor changes the extent to which the hydro generation algorithm in AURORAxmp® produces shapes that match load patterns and was necessary to counteract the distortion.

Q. Please describe the changes to the composition of generic renewable additions in California.

A. The renewable resource forecasting model relies on the composition and trends (in terms of shares of energy provided by different types of renewable resources) of existing renewable resource builds in each state to project the composition of future generic renewable builds needed to meet renewable portfolio standard (RPS) targets. Analysis of California indicates that available sites to build new wind resources are largely exhausted and that future renewable buildout will rely far more heavily on solar resources. Therefore, we calibrated our model to the standard buildout provided in the California

Public Utilities Commission's RPS calculator, which accounts for the limitation on wind resource additions.

Q. Why do you include California carbon pricing in the model?

A. Including mechanisms to reflect California carbon pricing has a substantial impact on prices in California and subsequently the spreads between Mid-C and California hubs. These spreads are now used to estimate premiums BPA receives when selling surplus energy into California. *See* Power and Transmission Risk Study, BP-18-E-BPA-05, § 4.1.1.2.3.

Q. Why do you assume the price of carbon emissions in California will remain at the auction floor price?

A. Since California's cap and trade program for carbon began, historical auctions have all cleared at, or very close to, the floor price. In addition, moderate to low economic growth in California, coupled with high renewable energy growth dampening the need for emission allowances in the power sector, suggests that demand for allowances will remain below levels necessary for the market to clear at higher prices during the BP-18 rate period.

Q. Were there any other changes to AURORAxmp® for the BP-18 Initial Proposal?

A. Yes. We currently run AURORAxmp® version 12.1.1043 and North American database version 2015-02, which are updated versions of the model and database used in the BP-16 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 BP-18 Final Proposal?

A. Yes. Likely the most substantial change involves resolving a discrepancy between calculated renewable resource additions necessary to meet RPS goals and energy produced by those resources in AURORAxmp®. This discrepancy was discovered late in

the process of producing the Initial Proposal forecast and requires revision of the model used to estimate needed levels and locations of generic RPS resource additions. It also requires further evaluation and possible updates to EPIS default renewable generation shapes and capacity factors. We will also make a correction to EPIS default values for CGS that should increase its output by about 20 aMW.

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

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 § 2.3.1.4.

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 set of future natural gas prices. In other words, this forecast is not necessarily the forecast that has the highest likelihood of being correct. Rather, it is a forecast that has a high likelihood of generating an equal probability of erring above or below future prices. By using the forecast to set median gas 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, lack of gas-fired generation load, or declining economics for LNG exports, supply growth has the potential to outpace demand growth. This could lead to another period of low natural gas prices, such as in 2015–16 and 2012, when prices fell below $3.00/MMBtu.

With new pipeline infrastructure and processing capacity scheduled to come on line in the Northeast U.S., a larger-than-expected flow of natural gas out of the Appalachian Basin could occur if most of these projects are completed on time. Following current trends, it is anticipated that some of these projects will be delayed. If they are not, the additional supply could drive prices below those forecast.

It is possible that a major advance in production technology could further decrease the cost of exploration, drilling, and well stimulation and place downward pressure on the marginal cost of gas. A fundamental change such as this could be cause to adjust the forecast.

Additionally, if the inventory of Drilled but Uncompleted Wells (DUCs) is brought down to normal levels and drilling levels and capital expenditures normalize, but prices have not risen to near the forecast, a reassessment of the expected marginal cost of production and of the forecast may be warranted.

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. A higher price forecast for FY 2018–2019 could be seen if there are delays to infrastructure expansions in the Appalachian Basin that are significantly beyond

expectations. Also, if there are any unexpected policy or legislative actions that would increase the cost of producing or transporting natural gas, prices might be expected to be higher than currently forecast.

If the inventory of DUCs is brought down to normal levels, drilling levels and capital expenditures normalize, and prices have risen to and maintained levels above that of the forecast, a reassessment of the expected marginal cost of production and of the forecast may be warranted.

A definitive shift 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 of prices, which is 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 id.*

Q. Have you made any changes to the Natural Gas Price Risk Model or data used to calibrate the model since BP-16?

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, 2016. In the BP-16 rate case we used daily historical Henry Hub nominal prices from January 1, 2009, to June 30, 2014.

Q. The Natural Gas Price Risk Model is an autoregressive model. 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 Figure 6 in the Study for the 5th, 50th, and 95th percentiles.

Q. Does this conclude your testimony?

A. Yes.