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TESTIMONY of

BEN K. KUJALA, SIDNEY L. CONGER, JR., DAVID K. DERNOVSEK, and

ROBERT J. PETTY

Witnesses for Bonneville Power Administration

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5
6 **SUBJECT: MARKET PRICE FORECAST**

7 **Section 1: Introduction and Purpose of Testimony**

8 *Q. Please state your names and qualifications.*

9 A. My name is Ben K. Kujala, and my qualifications are contained in BP-12-Q-BPA-43.

10 A. My name is Sidney L. Conger, Jr., and my qualifications are contained in
11 BP-12-Q-BPA-15.

12 A. My name is David K. Dernovsek, and my qualifications are contained in
13 BP-12-Q-BPA-18.

14 A. My name is Robert J. Petty, and my qualifications are contained in BP-12-Q-BPA-61.

15 *Q. What is the purpose of your testimony?*

16 A. The purpose of our testimony is to sponsor portions of the Power Risk and Market Price
17 Study (Study), BP-12-E-BPA-04, and the Power Risk and Market Price Study
18 Documentation (Documentation), BP-12-E-BPA-04A. Our testimony supports and
19 describes the information, data, and analyses contained in the Study and Documentation.
20

21 **Section 2: Market Price Forecasts**

22 *Q. How many electricity market price forecasts are derived for the Initial Proposal?*

23 A. We derive two electricity market price forecasts for the Initial Proposal: a market price
24 forecast that includes the impact that water volume and timing over 70 historical water
25 years have on Pacific Northwest (PNW) hydro generation, hereafter referred to as the

1 market price run, and a market price forecast in which PNW hydro generation is based on
2 the hydro generation only during the critical water year (1937), hereafter referred to as a
3 critical water run. The latter forecast is used only to estimate system augmentation price
4 risk. Both forecasts account for variability in several other factors, described later in this
5 testimony.

6 *Q. In general, how are these market price forecasts developed?*

7 A. We run the AURORAxmp model in an hourly mode, running 3,500 games. For each of
8 these “games,” variable values for the following risk factors are chosen from probability
9 distributions: natural gas prices; California and PNW load levels; PNW, California, and
10 BC hydroelectric generation levels; transmission path ratings on three different PNW
11 interties; Columbia Generating Station (CGS) generating performance; and PNW wind
12 generation levels. The AURORAxmp market price run contains 3,500 monthly
13 electricity market prices for Heavy Load Hour (HLH), Light Load Hour (LLH),
14 graveyard (hour ending 1am to hour ending 4am), and super-peak (top 8 price hours of
15 the day) time periods for FY 2012-2017. Study, BP-12-E-BPA-04, section 2.3.

16 *Q. Please describe, in general, the AURORAxmp model.*

17 A. AURORAxmp computes market prices using a production cost model. The model uses
18 data on all of the electricity generators in the Western Electricity Coordinating Council
19 (WECC) region. It groups generators into mutually exclusive and exhaustive subsets
20 called “zones,” based on a geographic breakout. The model assigns load to these
21 generators for each hour in the forecast period. The model computes the set of generators
22 that would provide the least-cost dispatch of power to serve that load, using defined
23 constraints such as start-up and shut-down restrictions on thermal generators for each
24 zone. It then applies another set of constraints based on available transmission capacity
25 in the region to calculate whether it would be cost effective to add generators to the least-

1 cost dispatch in one zone and “import” that power to another zone. It repeats the process
2 until each zone has a stable set of dispatched generators. Given this stable set of
3 dispatched generators, the model then calculates a “shadow price” that represents the
4 variable cost of generating power for the generator that would serve the next megawatt of
5 power demand. This shadow price is the forecast for the market price in a given zone,
6 and the generating unit that would supply that power is called the “marginal unit.”

7 *Q. Has BPA used this model in the past for market price forecasts for its rate cases?*

8 *A. Yes. BPA has used this model in all power rate cases since WP-02.*

9 *Q. What are the average annual flat electricity price results of the market price run?*

10 *A. The average annual flat electricity prices in nominal \$/MWh for the market price run, as*
11 *shown on Table 1 attached to this testimony, are \$37.32/MWh for FY 2012 and*
12 *\$42.01/MWh for FY 2013. For the monthly HLH and LLH price results, see the Study,*
13 *Table 2 and Table 3.*

14 *Q. What are the average annual flat electricity price results of the critical water run?*

15 *A. The annual average flat electricity prices in nominal \$/MWh for the critical water run, as*
16 *shown on Table 2 attached to this testimony, are \$41.81 for FY 2012 and \$47.16 for*
17 *FY 2013. For the HLH and LLH prices by month, see the Study, Table 4 and Table 5.*

18
19 **Section 3: Uses of the Market Price Run**

20 *Q. What is the market price run used for in this Initial Proposal?*

21 *A. Due to introduction of the Tiered Rate Methodology, the market price run is used for*
22 *more purposes than in previous rate cases. Two prior purposes remain: determining the*
23 *price for system augmentation power purchases and the price for surplus energy sales and*
24 *balancing power purchases.*

1 For example, the market price run is used in the Generation Inputs Study, BP-12-
2 E-BPA-05, to compute the variable cost component of generation input capacity. The
3 market price run is used in the Power Rates Study, BP-12-E-BPA-01 for:

- 4 (a) Prices for surplus energy sales and balancing power purchases in RAM2010,
- 5 (b) Load Shaping rate,
- 6 (c) Load Shaping True-up rate,
- 7 (d) Resource Shaping rate,
- 8 (e) Resource Support Service rates,
- 9 (f) Shaping the Demand rate,
- 10 (g) PF Tier 2 Balancing Credit,
- 11 (h) PF Unused RHWL Credit,
- 12 (i) Tier 1 PF Equivalent Rates,
- 13 (j) Melded PF Equivalent Rates,
- 14 (k) Balancing Augmentation Credit, and
- 15 (l) NR rate design.

16 Also, it is expected to be used in the REP-12 case for calculating utility average system
17 costs. Finally, it is used in the Study for the risk analysis.

18 *Q. What is the critical water year run used for?*

19 *A.* The critical water electricity price forecast is used to price the system augmentation costs
20 used in the RAM2012 for rate calculation purposes and in the risk analysis to account for
21 system augmentation cost risk.

22 *Q. Does the market price run include the 7(b)(2) period?*

23 *A.* Yes, the market price run includes FY 2014 through 2017 to be used for 7(b)(2) purposes
24 in the separate REP-12 rate proceeding. Study, section 2.4.

25

1 **Section 4: Risks Modeled in the Market Price Forecasts**

2 *Q. What risk factors are reflected in the market price run and critical water run in BP-12?*

3 A. The following risk factors are reflected in the market price forecasts in BP-12:

- 4 • PNW Hydroelectric Generation (except for the critical water run)
- 5 • BC Hydroelectric Generation
- 6 • California Hydroelectric Generation
- 7 • PNW Load
- 8 • California Load
- 9 • Natural Gas Price
- 10 • PNW Hourly Wind Generation
- 11 • Columbia Generating Station (CGS) Generation
- 12 • PNW Hourly Intertie Availability

13 These risks are addressed *passim* in Study section 2.3; models used to support these risk
14 analyses are listed in Study, section 2.2.3.1.

15
16 **Section 4.1: Risks Modeled in BP-12 that were Modeled in WP-10**

17 *Q. Which of these risk factors were reflected in the market price forecasts in WP-10?*

18 A. The following risk factors were reflected in the market price forecasts in WP-10:

- 19 • Natural Gas Price
- 20 • PNW Load
- 21 • California Load
- 22 • PNW Hydroelectric Generation
- 23 • California Hydroelectric Generation

24 WP-10 Risk Analysis and Mitigation Study, WP-10-FS-BPA-04, section 2.

1 *Q. Have the risk simulation models that quantify these risks changed since WP-10?*

2 A. Yes. In addition to updating data, we have made some changes to the risk models, as
3 described later in this section. Also, all the risk simulation models that provide data input
4 into AURORAxmp now have been designed to simulate risk data through the 7(b)(2) rate
5 test period, in addition to the FY 2012-2013 rate period.

6
7 **Section 4.1.1: Natural Gas Price**

8 **Section 4.1.1.1: Natural Gas Price Forecast**

9 *Q. How do you use the natural gas price forecast?*

10 A. The purpose of the natural gas price forecast is to provide monthly natural gas prices that
11 are needed in the Natural Gas Price Risk Model. Study, section 2.3.1.5.

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

13 A. No. The natural gas price forecast is reflected in the electricity market price forecast only
14 through its use as the median monthly prices of the natural gas price risk distribution used
15 when AURORAxmp runs 3,500 games for both the market price run and critical water
16 run.

17 *Q. Is the natural gas price forecast supposed to represent the most likely future natural gas
18 prices?*

19 A. No. The natural gas price forecast represents values that reflect a given conditional
20 probability, rather than the most likely future natural gas prices. That is, for median
21 prices there is a 50 percent probability that prices will be lower than the forecast, and a
22 50 percent probability that prices will be higher than the forecast, given the information
23 available today.

1 Q. *What have you changed since WP-10 regarding the methodology for establishing the*
2 *natural gas prices used in AURORAxmp?*

3 A. We have changed the methodology by adding eight major hubs for gas delivery in the
4 WECC area. In WP-10, there were only three hubs used in AURORAxmp: Opal,
5 representing the Rockies producing basin; Sumas, representing the Western Canadian
6 Sedimentary Basin; and Ignacio, representing the San Juan producing basin. WP-10
7 Market Price Forecast Study, WP-10-FS-BPA-03, section 3.3.1. Due to updates in
8 AURORAxmp by EPIS, eight additional hubs have been added. AECO and Kingsgate
9 represent the producing areas in Canada. Stanfield, OR, represents the intersection
10 between natural gas delivered from the Rockies and Canada. Malin, OR, represents an
11 intermediary point between the Pacific Northwest and California. Finally, PG&E
12 Citygate, SoCal Ehrenberg, SoCal Border, and Topock, Arizona, represent the San Juan
13 basin and associated California demand markets. Study, section 2.3.1.1.

14 Q. *What has changed since WP-10 regarding the overall state of the natural gas market?*

15 A. The most significant change in the natural gas market since the WP-10 Final Proposal is
16 the sharply increased supply from the vast domestic shale gas deposits. Domestic
17 production in the lower 48 states is at an all-time high despite a marked decrease in the
18 number of rigs since 2008, largely due to advances in the use of hydraulic fracturing and
19 horizontal drilling. The large increase in supply has outweighed the modest increase in
20 demand from the country's slow economic recovery. Additionally, the amount of natural
21 gas in storage continues to be at levels above the 5-year moving average. Study,
22 section 2.3.1.2.

1 *Q. Please summarize your natural gas price forecast for FY 2012-13.*

2 A. Our forecast for the annual average of the monthly forecast gas prices at Henry Hub in
3 nominal dollars is \$4.67/MMBtu in FY 2012 and \$5.30/MMBtu in FY 2013. Study,
4 section 2.3.1.3.

5 *Q. What assumptions did you use in developing the natural gas price forecast?*

6 A. We assumed that natural gas prices respond in a normal fashion to changes in supply or
7 demand. That is, any economic or market trends that increase supply or decrease demand
8 should have a downward effect on prices. Similarly, economic or market trends that
9 decrease expected supply or increase expected demand will have an upward effect on
10 prices. Current trends indicate an overabundance of supply as the dominant factor in
11 natural gas markets, pushing prices down toward the marginal cost of production, as well
12 as a lack of incremental demand necessary to provide balance to the market.

13 *Q. Please describe in more detail your assumptions that drive the natural gas price forecast.*

14 A. We assume that the economy continues a slow recovery throughout the remainder of
15 2010 and 2011. During 2010, increased demand by the industrial sector has led a
16 recovery of natural gas demand. Natural gas demand for power generation, residential
17 use, and commercial use has shown a more muted improvement. We assume, however,
18 that any likely additional increase in demand will have little impact on prices due to the
19 overwhelming amount of available supply. Supply will remain high because we see no
20 abatement in production. This is due to the relatively low marginal cost of production in
21 many domestic shale fields, as well as lease agreements that require producers to
22 continue drilling to retain rights to the lease. We also assume that any upward price
23 pressure from a downward trend in production will be at least partially offset by the high
24 levels of gas in storage. Seasonal volatility in gas demand, often a contributing factor to
25 high gas prices, is expected to decrease due to the number of major pipelines currently

1 planned for completion in 2011 and 2012. There are few feasible scenarios that could
2 increase demand to the level needed to rebalance the market. However, we think that the
3 overall result of the above conditions will be sustained low gas prices. Study,
4 section 2.3.1.2.

5 *Q. Please provide current evidence that supports the expectation of a sustained low natural*
6 *gas price environment.*

7 *A.* The state of the natural gas market in 2010 provides ample evidence of the effect of
8 supply on prices. Despite a hotter than average summer in most parts of the country,
9 which increased demand for gas in the power sector due to cooling needs, natural gas
10 prices stayed below \$4.00/MMBtu at Henry Hub and have settled well below this level
11 during the fall of 2010. A better than expected recovery in the industrial sector also
12 failed to buoy prices during recent months. Storage injections during September and
13 October of 2010 were on the high side, further supporting the notion of very high overall
14 storage levels that should naturally blunt any effects of increased demand during the
15 winter months. Finally, rig counts have not shown any sign of decreasing during 2010.
16 Given the amount of production we have seen from the current number of 900+ rigs, it is
17 unlikely that production will curtail in the upcoming months.

18 *Q. What changes in information between now and the Final Proposal would likely result in*
19 *revisions to the natural gas price forecast?*

20 *A.* While the supply and demand outlook is relatively well-defined at this point in time,
21 there are a number of factors that could influence this forecast for the Final Proposal.
22 Currently, producers are trending toward production of oil and natural gas liquids as
23 opposed to dry gas. In addition, many lease agreements that require active drilling are
24 expected to drop off or be renegotiated in the next couple of years. Both of these
25 conditions could result in decreased production, which could lead to higher prices. A

1 marked decrease in gas-only rig counts over the short term is a possible indicator of a
2 future decrease in production, though efficiency increases in rig technology could offset
3 this effect. Nonetheless, given the current overall production and storage levels, a major
4 downward shift in supply would likely be necessary to pressure prices upward.

5 *Q. What else could cause a change to the natural gas price forecast?*

6 A. The natural gas price forecast could change due to a variety of policy actions that could
7 provide upward price support by increasing costs or increasing demand. Increased
8 regulation of hydraulic fracturing or implementation of an excise tax on gas shale output
9 could lead to an increase in the cost of production. Also, adoption of stricter emission
10 regulations, including renewable portfolio standards or a carbon tax, would likely lead to
11 an acceleration of coal plant retirements, which could in turn spur gas demand in the
12 power sector. A definitive step toward any of the above factors could provide a basis for
13 adjusting the natural gas price forecast in the Final Proposal.

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

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

21
22 **Section 4.1.1.2: Natural Gas Price Risk**

23 *Q. Have you made any changes to the Natural Gas Price Risk Model since WP-10?*

24 A. Yes, several changes have been made to the Natural Gas Price Risk Model since the
25 WP-10 Final Proposal. The set of historical monthly natural gas price data used to

1 calculate monthly and annual natural gas price volatilities through time has been updated
2 and the source of these data revised from the natural gas hub at Ignacio, Colorado, to
3 Henry Hub, near Erath, Louisiana. Also, the historical and forecast natural gas prices
4 used in this risk model are now specified in terms of real 2008 dollars rather than the real
5 2005 dollars used in the WP-10 Final Proposal. We modified the forecast-reverting,
6 random-walk equation so that the calibration of the forecast reversion factors is
7 automated, as well as allowing the model to be coded such that it runs strictly in Excel
8 without the use of the @Risk computer software. We now calibrate the forecast
9 reversion factors using the Goal Seek functionality in Excel, which allows for consistent
10 and quick calibration. *Id.*

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

12 A. We incorporate natural gas price risk into our analysis because natural gas price
13 variability affects monthly HLH and LLH market electricity prices.

14 *Q. Why did you revise the source of the data used to calculate monthly and annual natural
15 gas price volatilities from the natural gas hub at Ignacio, Colorado, to Henry Hub, near
16 Erath, Louisiana?*

17 A. We revised the source of the data used to calculate monthly and annual natural gas price
18 volatilities from the natural gas hub at Ignacio, Colorado, to Henry Hub to make our
19 estimates of natural price risk consistent with the primary natural gas hub used to develop
20 the natural gas price forecast.

21 *Q. Please describe the forecast-reverting, random-walk technique used in the analysis of the
22 natural gas price risk.*

23 A. A random walk process produces variability that grows over time. This can result in a
24 larger than desired variance over a forecast horizon. To reduce the variance to a specified
25 level, we use a forecast-reversion factor. See Figure 9 in the Study. We refer to the

1 combination of these two techniques as a forecast-reverting, random-walk technique
2 hereafter.

3 *Q. Please describe how the forecast-reverting, random-walk technique is used to estimate*
4 *natural gas price risk.*

5 A. We model monthly natural gas price risk in the Natural Gas Price Risk Model using a
6 forecast-reverting, random-walk technique. The forecast reversion factors are calibrated
7 such that the simulated volatility in natural gas prices over time is consistent with the
8 volatility reflected in historical natural gas price data. Study, Figure 9.

9 *Q. Why do you use a forecast-reverting, random-walk methodology for modeling monthly*
10 *price risk?*

11 A. This methodology provides us with the flexibility to simulate natural gas prices that can
12 be more volatile in some months than others and that can rise and fall at different rates
13 during and across years. This flexibility is accomplished through the use of monthly and
14 annual forecast reversion factors, coupled with each month having different month-to-
15 month gas price volatilities. Thus, the flexibility associated with the methodology used
16 by the Natural Gas Price Risk Model allows the model to calibrate closely to the
17 attributes of gas price movements in historical data.

18 *Q. You previously used the terms mean-reverting random-walk and mean reversion factors*
19 *in WP-10. Why do you now refer to these as forecast-reverting random-walk and*
20 *forecast reversion factors?*

21 A. We have modified our terminology from mean-reverting and mean reversion factors to
22 forecast-reverting and forecast reversion factors because not all the risk models revert to
23 mean values. In particular, the Natural Gas Price Risk Model reverts to the median of the
24 natural gas price distribution. This is consistent with the deterministic natural gas price
25 forecast being considered the forecast of median prices. Study, Figure 9.

1 Q. *What do you mean when you use the terms “returns” and “volatility” in the Study when*
2 *quantifying natural gas price risk? How are these computed?*

3 A. We derive monthly and annual price volatilities for natural gas prices by computing the
4 standard deviations of all the natural log (*ln*) price ratio changes from one time period to
5 another. These natural log price ratio changes [*ln*(price at time *t* ÷ price at time *t-1*)] are
6 commonly referred to as “returns,” and the standard deviation of these returns is referred
7 to as “volatility.” Study, Figure 9.

8 Q. *In the Study you use the terms “volatility” and “variability” in regard to natural gas*
9 *price risk. Please explain the difference between these two terms.*

10 A. Volatility is specifically defined as the standard deviation values in terms of percentages.
11 For instance, a volatility of 30 percent means that a one standard deviation swing in price
12 is equal to 30 percent of the forecast price. Price variability, as measured by standard
13 deviation, is reflected in dollars and accounts for both the volatility and price level. Price
14 variability increases the higher the volatility and/or the price level.

15 Q. *Why do you compute returns and volatilities in this manner?*

16 A. We estimate monthly and annual price volatilities in this manner so that price movements
17 through time can be modeled using the forecast-reverting, random-walk technique
18 described above.

19 Q. *Why do you estimate historical volatilities using prices in real 2008 dollars?*

20 A. We estimate historical volatilities using prices in real 2008 dollars to remove the effect of
21 inflation over time on the calculation of volatility in the price data. Also, these
22 calculations are consistent with the fact that the natural gas price risk data used in
23 AURORAxmp are in real 2008 dollars. Study, Figure 9.

1 Q. *Why do you use the lognormal probability distribution when simulating natural gas price*
2 *risk?*

3 A. We compared the mean and median prices for the monthly and annual historical Henry
4 Hub natural gas prices from January 1991 through December 2009 and found that the
5 mean prices are greater than the median prices, a characteristic of the lognormal
6 distribution. Documentation, Table 1. The use of lognormal probability distributions for
7 quantifying price risk is a well established practice and also reflects that prices cannot go
8 below \$0.

9 Q. *What are the results from the Natural Gas Price Risk Model?*

10 A. Monthly results from the Natural Gas Price Risk Model are shown in Figure 1 in the
11 Documentation for the 5th, 50th, and 95th percentiles. The monthly natural gas price
12 variability patterns shown in this graph indicate that monthly gas price variability tends to
13 be higher when temperatures are cooler and lower when temperatures are warmer.

14 Q. *Do you make any adjustments to the simulated prices from the Natural Gas Price Risk*
15 *Model?*

16 A. Yes. We make month-specific price level adjustments to the simulated natural gas prices
17 to perfectly align the median monthly simulated gas prices to the monthly median prices
18 in the natural gas price forecast. Study, section 2.3.1.5.

19 Q. *Do the month-specific price level adjustments to the simulated natural gas prices alter*
20 *the price variability?*

21 A. No. The month-specific price level adjustments do not alter the price variability, because
22 each of these price level adjustments is applied to all simulated prices for that month.

23 Q. *Why do you begin simulating natural gas price risk in October of 2010?*

24 A. We turned off natural gas price variability prior to October of 2010 in the Natural Gas
25 Price Risk Model because actual historical data for the months prior to October of 2010

1 existed at the time we began our analysis, so we use the actual data for January through
2 September of 2010.

3
4 **Section 4.1.2: PNW Load**

5 *Q, Have you made any changes to the PNW Load Risk Model since the WP-10 Final*
6 *Proposal?*

7 A. Yes. We have made several changes to the PNW Load Risk Model (see Study,
8 section 2.3.2.4):

- 9 • The set of historical annual load data used to calculate annual load variability
10 through time is expanded to include data for 2006 through 2008.
- 11 • The forecast-reverting, random-walk equation is modified so that the calibration
12 of the forecast reversion factors is automated.
- 13 • The model is implemented such that it runs strictly in Excel without the use of the
14 @Risk computer software.
- 15 • The forecast reversion factors are calculated using the Goal Seek functionality in
16 Excel, which allows for consistent and quick calibration.
- 17 • The base year load and load growth rates now use AURORAxmp default values
18 rather than the previously-used WECC load forecast, which is no longer
19 published.
- 20 • The monthly standard deviation parameters associated with load variability due to
21 weather, which had been derived from data reported in the Marginal Cost Study
22 for the 1996 rate case, are revised. These parameters are now computed from
23 aggregated load data for all the regional Balancing Authorities' loads filed with
24 FERC on Form 714.

- In the WP-10 Final Proposal, the PNW load was decreased in AURORAxmp by 2,500 aMW for each of the 3,500 games. Now there is no such decrement.

Q. *In previous rate cases, you have decremented the loads in the PNW by 2,500 aMW to account for the market structure in the PNW as compared to the manner in which AURORAxmp forecasts the electricity prices. Are you still decrementing the loads in AURORAxmp?*

A. No. While the PNW still has a bilateral contract market, we believe the combination of the continued refinements made by EPIS, the owner and developer of AURORAxmp, to the AURORAxmp model and the continued refinements that we have made, stated earlier in this testimony, result in the AURORAxmp model estimating electricity market prices that better capture the current market environment. Thus, we believe the 2,500 aMW load decrement is not needed at this time.

Q. *Do you still have concerns over some of the electricity market prices that result from AURORAxmp?*

A. Yes. As stated in the policy testimony, Bliven *et al.*, BP-12-E-BPA-11, there is overall concern about the level of net secondary revenues. Also, from a price forecast standpoint, there are still some concerns about the resulting prices from AURORAxmp. Given the reduction in loads throughout the WECC and the addition of thermal generating plants and significant levels of wind generation, we are still concerned over the market dynamics that may occur and that are difficult to model. This concern is supported by some of the past spring runoff periods, when daily prices have been very low, even negative at times. Thus, we intend to explore and may make modifications to the price output of AURORA and/or net secondary revenue for the Final Proposal. These modifications would most likely be to the spring months, when hydroelectric generation levels are high. We are also concerned that, under conditions of very low hydroelectric

1 generation levels, market dynamics could drive prices higher than the model would
2 reflect.

3 *Q. Why do you include PNW load risk in the market price forecast?*

4 A. We include PNW load risk in our analysis because PNW load variability affects monthly
5 PNW HLH and LLH market electricity prices.

6 *Q. Please describe how you model PNW load risk.*

7 A. We model PNW load variability to account for both annual load growth variability and
8 monthly load swings due to weather conditions. We then quantify BPA monthly load
9 variability using the same percentage changes seen in the PNW loads. The forecast-
10 reverting, random-walk technique simulates various load patterns through time to model
11 annual PNW load growth risk. *Id.* Study, section 2.3.2.4.

12 *Q. Please describe how the forecast-reverting, random-walk technique is used to estimate
13 PNW, and indirectly BPA, load growth risk.*

14 A. As with the natural gas price risk model, the forecast-reverting, random-walk technique
15 simulates various annual average load levels through time. The starting point for
16 simulating annual average load in a given year is the annual average load level from the
17 previous year. The forecast-reversion factors are calibrated such that the simulated
18 variability in loads over time is consistent with the variability reflected in historical load
19 data.

20 *Q. What load data do you use to calculate the annual load growth variability values for the
21 PNW?*

22 A. We use Western Electricity Coordinating Council (WECC) load data for the Northwest
23 Power Pool Area from 1985-2008 to calculate the annual load growth variability values
24 for the PNW. Documentation, Table 3.

1 Q. *Why do you use WECC load data for the Northwest Power Pool Area from 1985-2008 to*
2 *calculate the annual load growth variability values for the PNW?*

3 A. We use the WECC data because we believe they are an accurate and representative
4 source of load data for the western United States.

5 Q. *Do you make any adjustments to the historical WECC load data for the Northwest Power*
6 *Pool Area when calculating the annual load growth deviations for the PNW?*

7 A. Yes. Historical annual DSI loads are removed from the historical annual PNW load data
8 before calculating the annual load growth deviations for the PNW. Study,
9 section 2.3.2.4.

10 Q. *Please describe the source of the historical annual DSI loads that are removed from the*
11 *historical annual PNW loads.*

12 A. The source of the historical DSI load data is metered data that includes DSI loads served
13 by both Federal and non-Federal purchases. The DSI load data used are from 1985
14 through 2008. The DSI load data do not include load served by Chelan PUD at the Alcoa
15 aluminum smelter located in Wenatchee, Washington. Study, section 2.3.2.4.

16 Q. *Why are historical annual DSI loads removed from the historical annual PNW load data*
17 *reported by WECC before calculating the annual load growth deviations for the PNW?*

18 A. Historical annual DSI loads are removed from the historical annual PNW load data
19 before calculating the annual load growth deviations for the PNW because we concluded
20 that not removing historical annual DSI loads would overstate annual PNW load
21 variability during FY 2012-2017 substantially more than removing historical annual DSI
22 loads would understate annual PNW load variability during FY 2012-2017.

1 Q. *Is this adjustment that removes DSI load from the calculation of annual load growth*
2 *deviations for the PNW consistent with what was done in the WP-10 Final Proposal?*

3 A. Yes, the adjustment that removes DSI load from the calculation of annual load growth
4 deviations for the PNW is the same method used in the WP-10 Final Proposal. WP-10
5 Risk Analysis and Mitigation Study Documentation, WP-10-FS-BPA-04A, section 2.4.2.

6 Q. *Please describe how you derive estimates of the variability in PNW monthly loads due to*
7 *weather conditions.*

8 A. Monthly PNW load standard deviations due to weather are derived from historical hourly
9 load data filed by every Balancing Authority in the PNW with the FERC on Form 714
10 from 1993 to 2005. The impact of load growth on these data is removed by taking a ratio
11 of the monthly average load to the annual average load and computing the standard
12 deviation of these ratios for each month. Study, section 2.3.2.4.

13 Q. *Did you include Balancing Authority Areas that are partially inside and outside the PNW*
14 *region in the PNW load risk model?*

15 A. Yes. We used 32.4 percent of the load reported by Northwestern and 43.1 percent of the
16 load reported by PacifiCorp. These values are used to be consistent with how the Council
17 defines regional load.

18 Q. *Why is the impact of load growth removed from the estimates of the variability in PNW*
19 *monthly loads due to weather conditions?*

20 A. In the Study, we are explicitly modeling load growth risk in the PNW Load Risk Model.
21 Accordingly, estimates of monthly load variability due to weather need to exclude the
22 impact of load growth so that we do not double-count the impact of load growth and
23 overestimate monthly load variability in this model.

24

1 **Section 4.1.3: California Load**

2 *Q. Have you made any changes to the California Load Risk Model since the WP-10 Final*
3 *Proposal?*

4 A. Yes. We have made the same changes to the California Load Risk Model that we made
5 to the PNW Load Risk Model just described.

6 *Q. Why do you include California load risk in the market price forecast?*

7 A. California load risk is incorporated into our analysis because California load variability
8 affects monthly HLH and LLH electricity market prices in the Pacific Northwest (PNW).
9 California loads affect electricity prices in the PNW because there are high capacity
10 transmission interties that connect California and the PNW region, and loads in
11 California impact the imports and exports to and from the PNW region. Study,
12 section 2.3.2.5.

13 *Q. Please describe how you model the California load risk.*

14 A. We model California load variability to account for both annual load growth variability
15 and monthly load swings due to weather conditions. Annual California load growth risk
16 is modeled to simulate various load patterns through time using a forecast-reverting,
17 random-walk technique in which load growth variability for the PNW and California are
18 interdependent. Study, section 2.3.2.5. The forecast-reverting, random-walk technique is
19 explained in Study, section 4.1.3.

20 *Q. Why do you model load growth variability for the PNW and California as*
21 *interdependent?*

22 A. Load growth variability for the PNW and California are modeled as interdependent
23 because there is a strong relationship between the two regional economies. This is
24 reflected in the high positive correlation (0.982) between historically observed annual
25 California and PNW (less DSI) loads. Documentation, Table 3.

1 *Q. What load data do you use to calculate the annual load growth variability for California?*

2 A. We use WECC load data for the California/Mexico Power Area from 1987-2008 to
3 calculate the annual load growth variability for California. Documentation, Table 3.

4 *Q. Why do you use WECC load data for the California/Mexico Power Area from 1987-2008
5 to estimate the standard deviation of the annual load growth forecast for California?*

6 A. We use the WECC data because we believe it is an accurate and representative source of
7 load data for the western United States. We use load data from 1987-2008. We do not
8 use the load data prior to 1987 because the WECC data for the California/Mexico Power
9 Area prior to 1987 includes loads in Southern Nevada. WECC data for the
10 California/Mexico Power Area from 1987-2008 does not include Southern Nevada.
11 Study, section 2.3.2.5.

12 *Q. Please describe how you derive estimates of the variability in California monthly loads
13 due to weather conditions.*

14 A. Monthly California load standard deviations due to weather are derived from historical
15 hourly load data filed by every Balancing Authority in California with FERC on Form
16 714 from 1993 thru 2005. The impact of load growth on these data is removed by taking
17 a ratio of the monthly average load to the annual average load and computing the
18 standard deviation of these ratios for each month. Study, section 2.3.2.5.

19 *Q. Why is the impact of load growth removed from the estimates of the variability in
20 California monthly loads due to weather conditions?*

21 A. The California Load Risk Model explicitly models load growth risk. Accordingly,
22 estimates of monthly load variability due to weather need to exclude the impact of load
23 growth so that we do not double-count the impact of load growth and overestimate
24 monthly load variability in this model.

1 *Q. Why is load variability due to weather conditions in the PNW and California modeled as*
2 *perfectly dependent within the two California regions (southern and northern California)*
3 *and the three PNW regions (Oregon/Washington, Idaho, and Montana) in AURORAxmp,*
4 *but independent between the California and PNW regions?*

5 A. Perfectly dependent variables have a strong functional relationship. Independent
6 variables have no statistical relationship. Intuitively, neither of these book-end
7 relationships is likely to accurately define the relationship that exists between the weather
8 in the PNW and California. However, we believe that this modeling approach represents
9 a reasonable trade-off between modeling either complete independence or dependence in
10 the PNW and California load variability. One would expect a relatively high positive
11 correlation between load swings due to weather within a region and a relatively modest,
12 but still positive, correlation between PNW and California load variability due to
13 weather. In light of these relationships, we believe our modeling approach provides
14 reasonable estimates of the impact that weather has on electricity market prices.
15

16 **Section 4.1.4: PNW Hydroelectric Generation**

17 *Q. What does PNW hydroelectric generation risk account for in your market price run?*

18 A. PNW hydroelectric generation risk accounts for the impact that historical variation in
19 streamflows has on monthly HLH and LLH electricity market prices.

20 *Q. Please describe how you incorporate PNW hydroelectric generation risk in*
21 *AURORAxmp.*

22 A. The method used for incorporating monthly PNW hydroelectric generation risk in
23 AURORAxmp is to use PNW hydro generation values estimated by the HYDSIM model
24 under streamflow conditions that occurred during 70 historical water years. Study,
25 section 2.3.3.1.

1 *Q. Why do you sequentially sample water years in the market price run?*

2 A. We sequentially sample water years in order to match the logic used in running
3 HYDSIM. For more information on how HYDSIM calculates PNW hydro generation
4 from these historical streamflows, see the Power Loads and Resources Study, BP-12-E-
5 BPA-03, section 3.1.2.1. PNW hydroelectric generation for each of the 70 water years is
6 derived by performing a “continuous hydro regulation study” where hydroelectric
7 generation is calculated sequentially over all 840 months of the 70 water years. In
8 sampling sequentially, AURORAxmp matches the logic of a “continuous hydro
9 regulation study.” Also, selecting hydroelectric generation data in a continuous manner
10 captures the risk associated with various dry, normal, and wet weather patterns that are
11 reflected in the 70 water year record and captures any year-to-year correlations in these
12 patterns.

13 *Q. In what way do you assign a water year from the 70 water year record with a game from
14 the 3,500 games?*

15 A. An index table of randomly sampled numbers ranging from 1929 to 1998 (representing
16 the 70 water years) is used to select, for each game, the amount of PNW hydro generation
17 to be used in AURORAxmp. These numbers are selected by sampling from a discrete
18 uniform distribution that starts at 1929 and ends at 1998. A random sample of 3,500
19 outcomes is pulled from this distribution, and the order in which it is pulled is used to
20 determine which AURORAxmp game is associated with which hydro generation record
21 based on the historical water year represented by the sampled number.

22 *Q. Why do you use the uniform probability distribution to assign water years to the games in
23 the market price run?*

24 A. We selected the uniform probability distribution because it assigns equal probability to
25 each of the 70 water years being sampled. After an initial water year is selected for the

1 first year of the rate period (FY 2012) for a given game, monthly PNW hydroelectric
2 generation data for a sequential set of seven water years are selected from water years
3 1929-1998. When the end of the 70 water years is reached (at the end of water year
4 1998), monthly hydroelectric generation data for water year 1929 are subsequently used.

5 *Q. Why is PNW hydroelectric generation data for the water year 1929 used when the end of*
6 *the 70 water years is reached at the end of water year 1998?*

7 *A.* This ensures that all water years are equally represented in the 3,500 seven-year water
8 sequences.

9
10 **Section 4.1.5: California Hydroelectric Generation**

11 *Q. Why do you include California hydroelectric generation risk in your analysis of*
12 *electricity market prices?*

13 *A.* California hydroelectric generation risk is incorporated into our analysis because it
14 affects monthly HLH and LLH electricity market prices in the Pacific Northwest.
15 California hydro generation affects electricity prices in the PNW because there are high-
16 capacity interties that connect California and the PNW region, and the amount and type
17 of generation in California impacts the imports to and exports from the PNW region.

18 *Q. How have your estimates of California hydroelectric generation risk changed since the*
19 *WP-10 Final Proposal?*

20 *A.* In WP-10, Staff randomly sampled from a set of historical monthly California hydro
21 generation data over 18 water years. These data were not matched with the HYDSIM
22 PNW hydroelectric generation data over the 70 water years due to the difference in the
23 number of observations. Since the conclusion of the WP-10 rate proceeding, Staff
24 collected actual monthly California hydroelectric generation data that span the same 70
25 water years used in HYDSIM. This historical record was translated into capacity factors

1 (energy generated / installed system capacity at the time of the hydro generation) to
2 account for the fact that installed hydroelectric generation capacity in California has
3 changed over time. We describe below how we then adjust these capacity factors to
4 account for the decline in capacity factors over time.

5 *Q. How did you adjust the historical California hydro generation capacity factors?*

6 A. We adjusted the historical California hydro generation capacity factors by removing a
7 downward linear trend in the historical capacity factors. The effect of these adjustments
8 is reductions in the capacity factors calculated for the earlier years in the historical
9 record. We refer to the resulting record as a “trend-adjusted” record. Study,
10 section 2.3.3.3.

11 *Q. Why did you remove the downward linear trend in the historical California hydro
12 generation capacity factors?*

13 A. We made downward linear trend adjustments to the California hydro generation capacity
14 factors because the market price forecast should incorporate a forecast of how the current
15 California hydroelectric system is operated under various hydro conditions. If better sites
16 for generation were developed first, and the modern sites are of lower quality, or
17 generation machines have been added to provide additional capacity with little change in
18 energy output over time, then the historical observations would yield capacity factors that
19 would not reflect modern operations. This downward linear trend adjustment helps
20 mitigate these phenomena.

21 *Q. Why is there no need to make trend adjustments to hydro generation estimates from
22 HYDSIM?*

23 A. There is no need to make the trend adjustments in HYDSIM because HYDSIM takes the
24 historical streamflows and simulates hydro generation based on the modern generation
25 capabilities and operation of the PNW hydroelectric system.

1 *Q. Please describe how California hydroelectric generation risk is used in AURORA_{xmp}.*

2 A. For each game of the 3,500 games, the number selected to represent the water year in the
3 PNW (as described in testimony section 4.1.1) is also used to select the generation from
4 the trend-adjusted California hydro generation data set.

5 *Q. Why do you use the same year in the index table to select the California hydroelectric
6 generation and the PNW hydroelectric generation from HYDSIM?*

7 A. We use the same number selected to represent the water year in the PNW to select the
8 generation from the trend-adjusted CA hydro generation data set to model the
9 relationship between the hydroelectric generation in these two regions.

10
11 **Section 4.2: Risks Added to the Market Price Forecast in BP-12**

12 *Q. What additional risks do you account for in development of the market price forecast in
13 this Initial Proposal?*

14 A. We account for the following additional risks in the market price forecast for this Initial
15 Proposal:

- 16 • BC Hydroelectric Generation;
- 17 • PNW Hourly Wind Generation;
- 18 • CGS Generation; and
- 19 • PNW Hourly Intertie Capacity Availability.

20
21 **Section 4.2.1: BC Hydroelectric Generation**

22 *Q. Why do you include BC hydroelectric generation risk in your analysis of electricity
23 market prices?*

24 A. BC hydroelectric generation risk is incorporated into our analysis because it affects
25 monthly HLH and LLH electricity market prices in the PNW. BC hydro generation

1 affects electricity prices in the PNW because there are high capacity-transmission
2 interties that connect BC and the PNW region, and the amount and type of generation in
3 BC impacts the imports and exports to and from the PNW region.

4 *Q. Please describe how you quantify BC hydroelectric generation risk.*

5 A. Staff collected actual historical monthly BC hydroelectric generation data that span the
6 same time period as the 70 water years used in HYDSIM. Study, section 2.3.3.2. These
7 data are adjusted in the same manner as the California hydroelectric generation described
8 in testimony section 4.1.5.

9 *Q. How did you adjust the historical BC hydro generation capacity factors?*

10 A. We adjusted the historical BC hydro generation capacity factors by removing an upward
11 linear trend in the historical capacity factors. These adjustments increase the capacity
12 factors calculated for the earlier years in the historical record. Study, section 2.3.3.2.

13 *Q. Why did you remove the upward linear trend in the historical the BC hydro generation
14 capacity factors?*

15 A. We made upward linear trend adjustments to the BC hydro generation capacity factors
16 because the market price forecast should incorporate a forecast of how the current BC
17 hydroelectric system is operated under various hydro conditions. If the dams on the
18 upper Columbia River resulted in higher capacity factors for BC hydroelectric generation
19 when they went into service than the BC hydroelectric generation that existed before
20 these dams were built, then these higher capacity factors would raise the overall capacity
21 factor of the BC hydroelectric system. Using this higher system capacity factor more
22 accurately reflects current BC hydroelectric generation.

1 *Q. Please describe how BC hydroelectric generation risk is used in AURORAxmp.*

2 A. For each game of the 3,500 games, the number selected to represent the water year in the
3 PNW (as described in testimony section 4.1.1) is also used to select the generation from
4 the trend-adjusted BC hydro generation data set. Study, section 2.3.3.2.

5
6 **Section 4.2.2: PNW Hourly Wind Generation**

7 *Q. Why do you include PNW wind generation risk in your analysis of electricity market*
8 *prices?*

9 A. We include the variability in PNW wind generation in our analysis because wind
10 generation affects the HLH and LLH market prices estimated in AURORAxmp. Wind
11 generation affects electricity prices in the PNW because wind generation is modeled as a
12 must-run resource and displaces other generators in the market. Study, section 2.3.4.

13 *Q. Why do you model PNW wind generation risk on an hourly basis?*

14 A. We model PNW wind generation risk on an hourly basis because the dispatch logic in
15 AURORAxmp accounts for startup and shutdown constraints for some thermal resources
16 when considering what resources are dispatched. Under certain conditions, these
17 constraints may result in a decision to leave a thermal plant in operation even if the
18 hourly shadow price calculated by AURORAxmp is less than the variable cost of
19 operation for that thermal plant. Without capturing the high variability of the shadow
20 price that results from hourly variation in wind generation, AURORAxmp may
21 inappropriately decide to supply more power from base load units with less flexibility
22 rather than thermal units with more flexibility. This in turn affects the electricity price,
23 because it changes the composition of the resource stack meeting the load in any given
24 hour.

1 *Q. What methodology do you use to model the PNW wind fleet generation variability?*

2 A. The method used is a k-nearest-neighbor (kNN) method, also referred to as a local
3 bootstrap. Study, section 2.3.4.1. The kNN method uses a historically observed time
4 series of data and samples from it with replacement. The selection of the next
5 observation is based on matching the pattern of the observations prior to the selected
6 observation to the previously sampled observations. Unlike a more traditional bootstrap
7 situation, this is done repetitively with a representation of time carried throughout the
8 sampling process. When the sampled record reaches a desired length, in this case a year
9 or 8784 hours, the process restarts. Multiple sampled synthetic time series are created in
10 this manner to produce the variability within a time period as well as across time.

11 *Q. A common approach used to estimate wind generation risk is to sample wind speed
12 estimates from a Weibull probability distribution and convert the wind speed estimates
13 into wind generation through a power curve. Why did you select the kNN method
14 instead?*

15 A. The Weibull distribution requires specification of a location at which the power will be
16 estimated. Wind speed measurements at that location are used to estimate the
17 distributional parameters. While this is a standard way of estimating power generation at
18 a specific location, it is difficult to generalize the method to an entire region. The kNN
19 method, on the other hand, takes the actual observed generation of the PNW wind fleet as
20 an input. This information is readily available and accounts for maintenance and planned
21 or unplanned outages experienced by the wind plants as well as the wind speeds
22 experienced fleet wide.

23

1 **Section 4.2.3: CGS Generation**

2 *Q. Why do you include CGS generation risk in your analysis of electricity market prices?*

3 A. We include CGS generation risk in our analysis because CGS generation affects HLH
4 and LLH market prices in the PNW. CGS generation affects electricity prices in the
5 PNW because a portion of the power generated by CGS is must-run, and the remaining
6 portion of the generation is produced at a low variable cost. Thus, CGS generation is
7 likely to displace more-expensive resources in the regional resource stack.

8 *Q. Please describe how you model the CGS generation risk.*

9 A. We model CGS generation risk in the CGS Generation Risk Model through a process that
10 involves sampling values from uniform probability distributions and substituting the
11 sampled values into a mathematical equation to simulate variability in CGS output.
12 Study, section 2.3.5.1.

13 *Q. Why do you model CGS generation risk in this manner?*

14 A. We model CGS generation risk in this manner because this methodology allows us to
15 calibrate the results from the mathematical equation such that, when all the simulations
16 are run, the average of the monthly simulated generation values is the same as the
17 expected monthly generation values reported in the Power Loads and Resources Study,
18 BP-12-E-BPA-03, section 3.1.3. Also, we selected this methodology because the
19 frequency distribution of CGS generation produced from the equation is negatively
20 skewed, with the median value (the value at the 50th percentile) being higher than the
21 average. The shape of the simulated frequency distribution of generation reflects that
22 thermal plants such as CGS typically operate at generation levels higher than the average
23 generation level. This is because the average generation level is driven down by
24 occasional forced outages that result in monthly generation values that can be
25 substantially lower than the typical monthly generation level. This modeling approach is

1 the same as that used in the WP-10 Final Proposal. WP-10 Risk Analysis and Mitigation
2 Study Documentation, WP-10-FS-BPA-04A, section 2.4.6.
3

4 **Section 4.2.4: PNW Hourly Intertie Capacity Availability**

5 *Q. Why does the BP-12 Initial Proposal include risk in the hourly intertie capacity*
6 *availability in the electricity market price forecast?*

7 A. AURORAxmp uses the availability of transmission capacity to determine whether or not
8 power can be transferred among zones as imports or exports. Study, section 2.3.7. If
9 initial model calculations indicate that the shadow price in one zone is less than the
10 shadow price in a neighboring zone and the modeled price of transmitting power from
11 one zone to the next is less than that difference, then the model will export the power
12 from the zone with the lower price to the zone with the higher price as long as adequate
13 transmission capacity is available. Such transfers cause the shadow price in the zone that
14 is exporting the power to increase while the shadow price in the zone that is importing the
15 power decreases. If the intertie capacity availability does not vary, the dispatch logic for
16 thermal plant operations can change, as explained in section 4.2.2. The combination of
17 transmission capacity availability with the wind generation risk allows the model to
18 emulate the decisions faced by thermal generation when there are highly volatile prices
19 within the month.
20

1 **Section 5: Non Risk-Based Updates to the Electricity Market Price Forecast**

2 **Section 5.1: WECC-Wide Renewable Portfolio Standards (RPS) Generation Additions**

3 *Q. Why do you include a forecast of WECC-wide RPS generation additions in the electricity*
4 *market price forecast?*

5 A. The addition of renewable generation in the PNW affects the shadow prices estimated by
6 AURORAxmp by adding additional resources to the generation stack. The addition of
7 renewable generation outside the region affects the exports to and imports from other
8 zones in the model. This in turn also impacts the shadow prices calculated in the model.

9 *Q. Is the inclusion of the WECC-wide RPS generation additions modeled as a risk?*

10 A. No. The inclusion of the WECC-wide RPS generation additions is not modeled as a risk.
11 These generation additions are included as a deterministic forecast that is integrated into
12 AURORAxmp.

13 *Q. What sources do you use for this forecast of RPS-driven generation additions?*

14 A. We use a combination of the Northwest Power and Conservation Council's RPS
15 additions forecast from the Sixth Power Plan and the wind generation forecast in the
16 Generation Inputs Study, BP-12-E-BPA-05.

17 *Q. Why do you use the forecast of RPS-driven generation additions from these two sources?*

18 A. We use the Council's Sixth Power Plan estimates for RPS-based construction outside the
19 region because the Council is a reputable regional source and the forecast has been
20 through a public review process. We use the wind generation forecast from the
21 Generation Inputs Study (section 2.3.2) to be consistent with other studies in the Initial
22 Proposal and to capture the generation being built within the region to serve RPS
23 requirements outside the region. Because the Generation Inputs Study presents a forecast
24 of only wind generation connected to BPA's Balancing Authority, we also include the
25 minimal forecast for the PNW region in the Council's Sixth Power Plan.
26

1 **Section 6: Potential Final Proposal Updates**

2 *Q. Are there potential general updates to the inputs and assumptions used in the Market*
3 *Price run and Critical Water run for the Final Proposal?*

4 A. Yes. The following are potential updates that may be made for the Final Proposal.

- 5 • If EPIS releases a new North American database, it may be used in the Final
6 Proposal.
- 7 • If EPIS releases a new version of AURORAxmp, it may be used in the Final
8 Proposal.
- 9 • The projected wind capacities for the BPA zone will be updated to match the
10 forecast from the Generation Inputs Study used in the Final Proposal.
- 11 • The natural gas price forecast may be revised to reflect an updated outlook based
12 on newer information, as described in section 4 of this testimony.
- 13 • We may update the RPS generation build forecast based on updated information.
- 14 • We will examine the recent shift in AURORAxmp from using natural gas prices
15 at Sumas as the basis for natural gas pricing for regional generators to using
16 natural gas prices at the added Stanfield natural gas hub.
- 17 • If a new PNW hydroelectric generation forecast is available from HYDSIM for
18 the rate period, it will be used in the final electricity market price forecast.
- 19 • We will monitor and account for changes to large new or existing resources and
20 transmission lines.
- 21 • Many of our models use historical data as an input. To the extent that new
22 historical data are available, we will update our models for the Final Proposal.
- 23 • We will also use any updated forecast information from other related final studies.

24 *Q. Are there specific updates that you anticipate at this time?*

25 A. Yes. In the WP-10 Final Study we used a floor price for natural gas of \$1.75/MMBtu, in
26 real 2005 dollars, in the Natural Gas Price Risk Model. WP-10 Risk Analysis and

1 Mitigation Documentation, WP-10-FS-BPA-04A, section 2.4.5.1. This floor value
2 prevented the monthly simulated natural gas prices in this model from falling below
3 \$1.75/MMBtu; this floor price was based on historical natural gas price data at Ignacio,
4 Colorado. Since the conclusion of the WP-10 rate proceeding, the Natural Gas Price Risk
5 Model has been revised to simulate natural gas prices at Henry Hub. The data in the
6 model have also been converted into real 2008 dollars. We did not reevaluate this floor
7 price for the Initial Proposal. The \$1.75/MMBtu floor price was carried forward without
8 accounting for the transition from prices in real 2005 dollars to real 2008 dollars. Thus,
9 our current model effectively has a floor price of \$1.75/MMBtu in real 2008 dollars when
10 simulating natural gas price risk at Henry Hub. Study, section 2.3.1.5. We intend to
11 reevaluate this floor price for the BP-12 Final Study. Also, we plan to update the
12 historical natural gas price volatilities used when simulating natural gas price risk to
13 correct for a minor formula error.

14 *Q. For the Final Study, do you expect any changes to the modeling in AURORAxmp due to*
15 *the recent election season in California?*

16 *A. Potentially we will add assumptions to reflect carbon pricing as a result of the recent*
17 *election in California and any resulting impact on AB-32, a California bill that establishes*
18 *a cap-and-trade system for carbon emissions from electricity generators. In the Initial*
19 *Proposal, we assumed there would be no carbon cost reflected in PNW market prices for*
20 *electricity. If AB-32 is considered likely to go into effect during FY 2012-2013, then it is*
21 *likely that there would be a cost associated with carbon emissions in California.*
22 *Accordingly, we may change the settings in AURORAxmp to model the cost of*
23 *emissions of generators in California and also add to imported power a cost for carbon.*

24 *Q. Does this conclude your testimony?*

25 *A. Yes.*

Section 7: Tables

Table 1: Prices for AURORAxmp Market Price Run (Nominal \$/MWh)

A	B	C
Hours	FY 2012	FY 2013
HLH	\$42.31	\$47.68
Flat	\$37.32	\$42.01
LLH	\$30.99	\$34.78

Table 2: Prices for AURORAxmp Critical Water Run (Nominal \$/MWh)

A	B	C
Hours	FY 2012	FY 2013
HLH	\$46.82	\$52.87
Flat	\$41.81	\$47.16
LLH	\$35.45	\$39.88