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2003 Safety-Net Cost Recovery Adjustment Clause Initial Proposal

Study

Chapter 4 – Secondary Revenue Forecast

SN-03-E-BPA-01

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BONNEVILLE
POWER ADMINISTRATION

CHAPTER 4: SECONDARY REVENUE FORECAST

4.1 Introduction

4.1.1 Definitions and Purposes. This chapter presents BPA's secondary revenue forecast for its SN CRAC power rate case. The secondary revenue forecast estimates the amount of revenue BPA expects to make in marketing its surplus energy. BPA used the AURORA model to estimate the prices BPA expects to receive in the surplus energy market. AURORA calculates the variable cost of the marginal resource in a competitively priced energy market. In competitive market pricing, the marginal cost of production is equivalent to the market-clearing price. Market-clearing prices are important factors in determining BPA's bulk power revenues. Therefore, the marginal clearing price estimates inform BPA's forecast of secondary revenues in the rate case. Chapter 6 of this Study, Risk Analysis, explains the use of AURORA prices in determining the secondary revenue forecast.

4.1.2 AURORA Model Framework. AURORA assumes a competitive pricing structure as the fundamental mechanism underlying the determination of wholesale electric energy prices during the term of this analysis. Two fundamental inferences for energy pricing follow from the economic theory of market pricing. First, the price in any hour will approximate the variable cost of the marginal generating resource. Second, the long-term average price will gravitate toward the full cost of a new resource.

As noted above, the inference on hourly prices follows directly from economic market pricing theory. Economic theory concludes that a firm will continue to produce additional goods or services as long as the revenue from the sale of those units covers the marginal cost. A competitive market will produce up to the quantity where the amount consumers are willing to pay for marginal consumption is equal to the marginal cost of production. Therefore, the market-clearing price is equal to the cost to produce the marginal unit for consumption. For the electricity market, the hourly market-clearing price translates to the variable cost from the marginal electric generator.

In the long-term, when the amount of capital is not fixed, the average price will move toward the full cost of a new resource. When prices are high enough to justify additional investment, the average investment cost will be lower than the average price. Therefore, new resources will bring down the price. When the long-term average price outlook is lower than the average cost of a new resource, new resources will not be built. In this case, demand growth will move prices up the supply curve until new resource investment is profitable.

Since long-term prices will gravitate toward the cost of new resources, the assumptions concerning the cost of a new resource will have an important impact on the long-term price forecast. It is assumed that the bulk of new electric power generation will be combined-cycle combustion turbines (CCCT). Another important assumption is the load forecast. This assumption will affect how quickly prices move up the supply curve and reach the point where investment in new resources is profitable.

Economic theory also concludes that until prices reach the level where new resource investment is profitable, excess capacity will decline. A decline in excess capacity will tend to exacerbate price increases in those periods where capacity has relatively less surplus: the peak pricing months and heavy load hour periods. The average levels of monthly prices and the heavy and light load hour prices for each month are given in Section 4.4 of this chapter.

4.2 Methodology

4.2.1 Overview. The principal tool used in this analysis is an electric energy market model called AURORA. AURORA is owned and licensed by EPIS, Incorporated. Production costing is a subset of AURORA's functions. Production cost models are widely used in the electric power industry. Production cost models follow a general structure and AURORA is consistent with this structure.

To describe AURORA's methodology it is helpful to distinguish between two main aspects of modeling the electric energy market: the short-term determination of the hourly market-clearing price and the long-term optimization of the resource portfolio.

4.2.2 Hourly Price Determination. The hourly market-clearing price is based upon a fixed set of resources dispatched in least cost order to meet demand. The hourly price is set equal to the variable cost of the marginal resource. AURORA sets the market-clearing price using assumptions on demand levels (load) and supply costs. The supply side is defined by the cost and operating characteristics of individual electric generating plants, including resource capacity, heat rate, and fuel price.

AURORA recognizes the effect that transmission capacity and prices have on the ability to move generation output between areas. AURORA recognizes 13 areas within the Western Electricity Coordinating Council (WECC, formally called the WSCC), largely defined by the transmission grid.

4.2.3 Long-Term Resource Optimization. The long-term resource optimization feature within AURORA allows generating resources to be added or retired based on economic profitability. Economic profitability is measured as the net present value of revenue minus the net present value of costs. A potential new resource that is economically profitable will be added to the resource database. An existing resource that is not economically profitable will be retired from the resource database.

In reality, the market-clearing price (hence the profitability of a resource) and the resource portfolio are interdependent. The market-clearing price will affect the revenues any particular resource will receive, and consequently which resources are added and retired. In parallel, changes in the resource portfolio will change the supply cost structure and will therefore affect the market-clearing price. AURORA uses an iterative process to address this interdependency.

AURORA's iterative process uses a preliminary price forecast to evaluate existing resources and potential new resources in terms of economic profitability. If an existing resource is not profitable, it becomes a candidate for retirement. Alternatively, if a potential new resource is economically profitable, it is a candidate to be added to the resource portfolio. In the first step of the iterative process, a small set of new resources is drawn from those with the greatest profitability and added to the resource base. Similarly, a small set of the most unprofitable existing resources is retired. This modified resource portfolio is used in the next step in the iterative process to derive a revised market-clearing price forecast. The modified price will then drive a new iteration of resource changes. AURORA will continue the iterative solution of the resources portfolio and the market-clearing price until the difference in price between the last two iterations reaches a minimum and the iterative process converges to a stable solution.

4.2.4 Application of AURORA for the Secondary Revenue Forecast. For the secondary revenue forecast, AURORA was run in a probabilistic mode. When running the probabilistic forecast, BPA altered hydro conditions, load conditions, and natural gas price conditions. The expected values of these inputs are found in Section 4.3 of this chapter. The methodology and resulting variations around the inputs are found in Chapter 6 of this Study, Risk Analysis. The Risk Analysis Study provided the variations in the inputs that were used to supply AURORA. AURORA was run for 3,000 games with monthly average HLH and LLH prices forecasted for the remainder of the rate period. The resulting prices were then used in RiskMod to derive the probabilistic secondary revenue forecast.

As stated in the testimony of Oliver, *et al.*, SN-03-E-BPA-08, BPA decremented the loads in Oregon, Washington, and Northern Idaho by 2,500 aMW to reflect the fact that BPA does not market power in a market that has an exact hourly marginal clearing price. Instead, BPA markets power in a bilateral market in which every party does not receive the highest hourly marginal clearing price. To decrement the loads in Oregon, Washington, and Northern Idaho in RiskMod by 2,500 aMW, BPA lowered the expected value load forecast for those areas by 2,500 aMW.

4.3 Assumptions

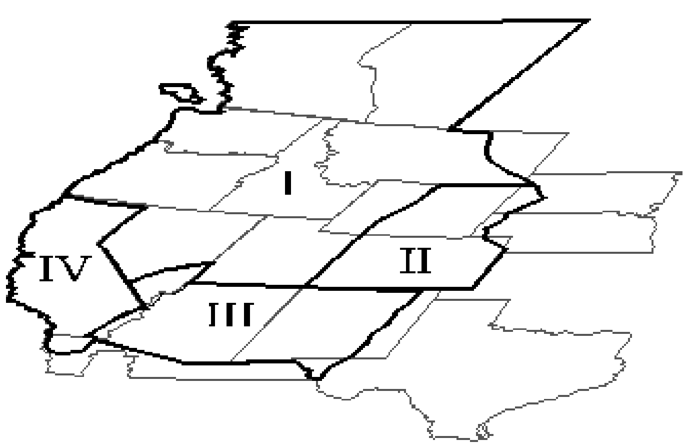
4.3.1 Overview. There are three primary assumptions that are relevant to the secondary revenue forecast: the load forecast, the natural gas price forecast, and the assumptions about hydro conditions. The load forecast determines where on the supply curve the marginal clearing price is determined. Natural gas prices will generally determine the variable cost of the resource on the margin that sets the marginal clearing price. Hydroelectric generation conditions determine the amount of hydroelectric generation that can be used to meet loads and thus add to the location on the supply curve in which the marginal clearing price is determined. Consequently, the assumptions on the load forecast, natural gas prices, and hydro conditions are described in detail this section.

A number of other relevant assumptions are discussed in the following sections. Remaining data and assumptions that are required to run AURORA are listed in the Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 4.

4.3.2 Load Forecast. The load forecast for AURORA consists of four parts: the base-year load forecast; the annual average growth rate; monthly load shape factors; and hourly load shape factors. The base year load forecast determines the starting level for the loads. The annual average growth rate increases the loads over time. The monthly load shape factors shape the annual loads into monthly loads. The hourly load shape factors then shape the monthly loads into hourly loads.

4.3.2.1 Base-Year Load Forecast. For the base-year load forecast input to AURORA, BPA relied on the WECC 10-Year Coordinated Plan Summary (2000-2009) load forecast. The WECC forecasts loads for four regions: the Northwest Power Pool Area, the California–Mexico Power Area, the Rocky Mountain Power Area; and the Arizona–New Mexico–Southern Nevada Power Area. Figure 4-1 represents these areas:

Figure 4-1: 2002 WECC Regions



Where: I = Northwest Power Pool Area

II = Rocky Mountain Power Area

III = Arizona–New Mexico–Southern Nevada Power Area

IV = California–Mexican Power Area

The four WECC regions were converted into 13 AURORA areas for BPA's forecasts. Table 4-1 represents the 13 AURORA areas:

Table 4-1: AURORA Areas

AREA NUMBER	AREA NAME	SHORT AREA NAME
1	Oregon/Washington/IdahoNorth	OWI
2	Northern California	NoCA
3	Southern California	SoCA
4	British Columbia	BC
5	Idaho South	IDSo
6	Montana	MT
7	Wyoming	WY
8	Colorado	CO
9	New Mexico	NM
10	Arizona/NevadaSouth	AZNV
11	Utah	UT
12	Nevada North	NVNo
13	Alberta	AB

The methodology used to convert the WECC regional loads can be seen in the following example. With the Northwest Power Pool Area, the loads in the original AURORA database for OWI, BC, IDSo, MT, UT, NVNo, and AB were summed to produce an aggregate total load. The loads for OWI, BC, IDSo, MT, UT, NVNo, and AB were each divided by the aggregate total load to develop individual percentages. The individual percentages were then applied to the aggregate WECC regional load forecast for the Northwest Power Pool Area 2000 load forecast for AURORA areas OWI, BC, IDSo, MT, UT, NVNo, and AB. This procedure was then repeated for each of the WECC regions to derive each AURORA area 2000 base-load forecast. For this chapter, the PNW is the synonymous with the OWI, IDSo and MT areas.

4.3.2.2 Annual Average Growth Rate. BPA used an average annual growth rate from the WECC 10-Year Coordinated Plan Summary 2001-2010. BPA used these WECC regional growth rates to reflect its prediction that loads will grow at different rates in the different WECC regions. BPA assumed very minimal load growth for PNW loads for the 2001 and 2002 time frame. This was based on the reduced amount of direct service industrial load that BPA serves. Table 4-2 shows the WECC annual growth rates used in the Secondary Revenue Forecast:

Table 4-2: Load Forecast Annual Average Growth Rate in Percents

Area	NWPA	RMPA	AZ/NM/SO NV	CA-MX
2002	1.9	3.1	3.6	2.6
2003	1.7	3.2	3.0	2.7
2004	1.7	2.5	2.1	2.7
2005	2.0	2.1	3.0	2.7
2006	1.8	2.1	2.8	2.7

BPA applied the annual average growth rate to the base load forecast to determine the load forecast over time.

4.3.2.3 Monthly and Hourly Load Shaping Factors. BPA used the default AURORA load shaping factors for converting the annual load forecast into a monthly load forecast. AURORA multiplies the monthly shaping factor by the annual load forecast to derive the monthly load forecast. BPA also used the default hourly load shaping factors provided for converting the monthly load forecast into an hourly load forecast.

4.3.3 Natural Gas Prices

4.3.3.1 Methodology. The natural gas price forecast used in BPA's surplus revenue forecast includes a natural gas price for each of the AURORA areas. The first step of the natural gas price forecast is a forecast of prices at Henry Hub. Henry Hub is the major pricing and trading hub for North American natural gas. The next step forecasts the price differential (basis) between Henry Hub and three western United States natural gas hubs: Sumas, Opal, and Ignacio. Each of these hubs represents a price from a distinct production area. Sumas is representative of the Western Canadian Sedimentary Basin, Opal is representative of the Rocky Mountain basins, and Ignacio is representative of the San Juan Basin. The final forecasting steps match each western hub to an AURORA area and then forecasts the difference between the relevant western hub price and price of natural gas delivered to an AURORA area.

4.3.3.2 Assumptions and Results. BPA's forecast of Henry Hub prices draws on an internal analysis of market fundamentals and compares BPA's analysis to a NYMEX futures price for natural gas at Henry Hub. BPA's price forecast references the most current NYMEX pricing available for the SN CRAC study: January 28, 2003. This NYMEX futures price series shows a price spike of nearly \$5.00/MMBtu in 2003, followed by a decline to \$3.84/MMBtu in 2006.

NYMEX prices for 2003 are consistent with BPA's short-term price expectations. BPA set its Henry Hub forecast equal to the NYMEX futures contracts for this year. However, BPA's gas price forecasts for 2004 and 2005 were reduced \$0.25/MMBtu from NYMEX prices. At the time the SN CRAC forecast was completed, gas prices were in the midst of a significant price spike. When prices are spiking there may be an over-reaction in futures market pricing that goes beyond demand and supply fundamentals. BPA forecasts prices slightly below NYMEX in 2004 and 2005. By 2006, NYMEX futures prices fall to a level that is more consistent with BPA's outlook. BPA's Henry Hub forecast was set equal to NYMEX futures prices in 2006. The following Graph 4-1 and Table 4-3 show historical Henry Hub prices, BPA's Henry Hub price forecast, and the January 28, 2003, NYMEX futures prices.

Graph 4-1: Natural Gas Prices at Henry Hub (Nominal $/MMBtu)

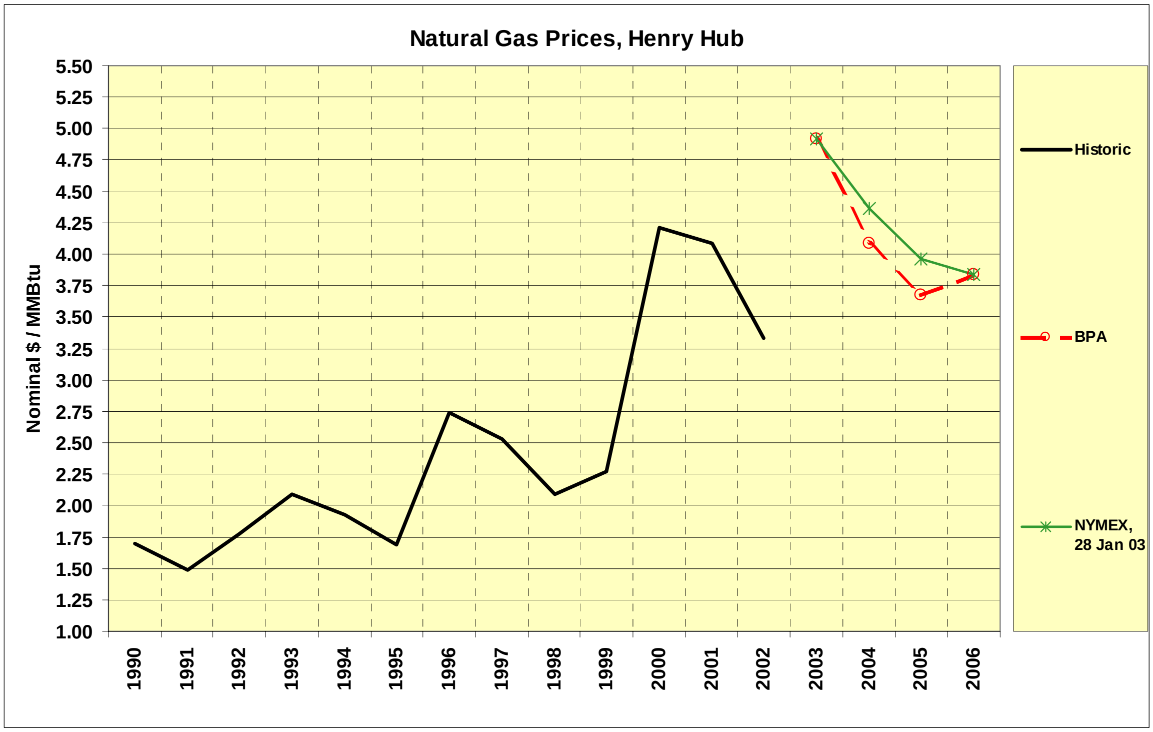


Table 4-3: Henry Hub Natural Gas Prices

Henry Hub Natural Gas Prices ($/MMBtu)												
	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Nominal $												
Historic	1.69	2.74	2.53	2.09	2.27	4.21	4.08	3.33				
Forecast									4.91	4.08	3.67	3.84
Real 2000$												
Historic	1.84	2.93	2.65	2.17	2.31	4.21	3.99	3.17				
Forecast									4.57	3.71	3.25	3.32

The next step in developing BPA's natural gas price forecast calculates forecasted price differentials from Henry Hub to the three western pricing hubs. These price differential forecasts are based on historical pricing differentials and expectations for future pipeline developments. Increases of pipeline capacity out of a production basin will diminish the basis as supply bottlenecks are relieved and basin prices more closely approximate continental averages. BPA's natural gas price forecast assumes an increase in pipeline capacity out of the Rocky Mountain basins in 2004 due to the Kern River pipeline expansion. Therefore, the basis from Opal declines sharply in 2004. The basis from Ignacio also declines in 2004 due to some smaller pipeline additions and some feedback from the Kern expansion. The basis and the resulting prices for each western hub are shown in Table 4-4 below.

Table 4-4: Hub Gas Prices and Basis to Henry (Real 2000$/MMBtu)

Henry Hub Price	Western Hubs					
	Basis			Price		
	Sumas	Opal	Ignacio	Sumas	Opal	Ignacio
4.57	-0.50	-1.35	-0.55	4.07	3.22	4.02
3.71	-0.50	-0.45	-0.30	3.21	3.26	3.41
3.25	-0.50	-0.45	-0.30	2.75	2.80	2.95
3.32	-0.50	-0.45	-0.30	2.82	2.87	3.02

The final steps in BPA's natural gas forecast match each western pricing hub to an AURORA area and then forecast a price differential between the relevant hub and the AURORA area. The pricing differentials between each hub and the AURORA areas were drawn from the Northwest Power Planning Council's Draft Fifth Power Plan. BPA reviewed this information and it is consistent with BPA's analysis. The western pricing hubs, their matching AURORA areas, and the price differentials are shown in the following Table 4-5.

Table 4-5: Hubs, AURORA Areas and Basis (Real 2000$/MMBtu)

Western Hub	AURORA Area	Price Differential
Sumas	Pacific Northwest	0.23
Sumas	Western Canada	0.20
Sumas	Northern California	0.31
Opal	Idaho	0.35
Opal	Montana	0.33
Opal	Wyoming	0.40
Opal	Utah	0.35
Igancio	Southern California	0.47
Igancio	Colorado	0.36
Igancio	New Mexico	0.33
Igancio	Arizona	0.41
Igancio	Nevada	0.46

The final gas price forecasts for each AURORA area are shown in Table 4-6.

Table 4-6: Gas Price Forecasts for AURORA Areas (Real 2000$/MMBtu)

Aurora Gas Price Forecast Input				
	2003	2004	2005	2006
NW Nat Gas	4.29	3.43	2.98	3.04
N.Cal Nat Gas	4.38	3.52	3.06	3.13
S.Cal Nat Gas	4.49	3.88	3.42	3.49
Can Nat Gas	4.27	3.41	2.95	3.02
Id Nat Gas	3.57	3.61	3.15	3.22
Mt Nat Gas	3.55	3.59	3.13	3.20
Wy Nat Gas	3.62	3.66	3.20	3.27
Co Nat Gas	4.38	3.77	3.31	3.38
NM Nat Gas	4.35	3.74	3.28	3.35
Az Nat Gas	4.43	3.82	3.36	3.43
Ut Nat Gas	3.57	3.61	3.15	3.22
Nv Nat Gas	4.49	3.87	3.42	3.48

4.3.4 Hydroelectric Generation. For the secondary revenue price forecast, AURORA was supplied hydroelectric generation levels for the PNW area from Chapter 2 of this study, Loads and Resources. For the California area, hydroelectric generation conditions were supplied from RiskMod. For the PNW, 50 water years were used for the variation in hydroelectric conditions. For the California area, 18 years of historical hydroelectric generation levels were used for determining hydroelectric generation variability. For the remaining areas, AURORA default values were used. For monthly and hourly shaping factors BPA used the default database. BPA is currently reviewing the monthly shaping factors and may update them for the final study.

4.3.5 Generating Resource Update. BPA added generating resources to be consistent with the most current data available. BPA updated resources that BPA expected to be operating through the 2003 time frame. After 2003, BPA let AURORA determine which resources would be added or deleted within the AURORA database. No new resources were added in the PNW during the 2004-2006 timeframe. A complete listing of all the resources can be found in the Documentation for SN-03 Study, SN-03-E-BPA-02.

4.3.6 Other Assumptions. For the secondary revenue forecast, BPA used AURORA version 5.6.33. AURORA was run sampling every other hour for Monday, Wednesday, Friday, and Sunday for the first and third week of every month. For the assumptions not mentioned above, BPA used the default database supplied with version 5.6.33. These assumptions are contained in the Documentation for SN-03 Study, SN-03-E-BPA-02.

4.4 Results

4.4.1 Price Results. The complete results of the Secondary Price Forecast can be found in the Documentation for SN-03 Study, SN-03-E-BPA-02, Chapter 4. The results are expressed in terms of monthly average heavy load hour and light load hour prices. The following Tables 4-7 and 4-8 represent the prices as well as some summary statistics.

Table 4-7: FY 2003 Price Estimates

HLH	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03
Mean	49.59	51.20	48.83	46.10	39.37	37.75	42.35	44.69	47.35
Median	49.29	50.64	47.99	45.55	40.59	38.99	42.89	43.51	46.52
Maximum	83.48	97.90	99.50	84.09	82.62	96.74	101.65	91.57	109.10
Minimum	31.47	27.02	21.21	19.48	7.30	8.80	15.41	17.96	18.68
Standard Deviation	6.16	9.20	10.31	10.28	13.76	14.89	13.88	10.84	11.39
LLH	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03
Mean	42.10	43.48	40.08	38.55	32.22	26.16	35.60	40.45	44.99
Median	41.88	42.70	39.38	38.19	32.98	26.43	35.99	39.40	44.14
Maximum	62.11	86.42	87.80	73.38	65.89	73.61	86.75	82.51	94.64
Minimum	26.42	20.51	15.93	17.57	10.41	6.54	13.98	17.59	18.09
Standard Deviation	5.24	8.83	9.21	9.02	9.81	9.41	11.76	9.21	10.60

Table 4-8: FY 2004–2006 Price Estimates

HLH	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04
Mean	41.46	46.24	45.08	42.18	38.54	31.60	30.21	23.47	18.21	24.28	33.23	36.53
Median	40.45	45.14	43.66	41.83	37.53	30.87	29.76	23.08	17.20	22.09	32.01	35.81
Maximum	96.09	90.58	102.46	99.43	113.20	74.34	68.01	63.65	63.25	122.00	129.37	83.75
Minimum	17.04	20.44	16.96	7.43	11.56	7.19	9.95	3.44	2.78	6.91	13.75	13.29
Standard Deviation	10.31	10.74	11.66	14.32	12.35	9.58	9.81	11.16	8.47	8.90	10.05	9.63
LLH	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04
Mean	36.78	39.15	39.21	34.14	32.79	27.14	27.13	21.01	14.40	22.23	31.82	37.31
Median	36.02	38.09	37.98	33.86	31.86	26.36	26.63	20.44	14.60	20.33	31.03	36.43
Maximum	82.07	78.49	88.89	85.01	106.27	62.30	59.03	50.23	48.38	53.51	76.55	74.50
Minimum	16.10	17.55	15.20	8.82	12.65	7.54	10.85	3.72	2.75	6.51	13.88	17.33
Standard Deviation	8.78	9.13	10.27	12.72	10.65	7.93	8.09	7.17	6.51	7.50	8.03	8.76
HLH	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05
Mean	37.13	42.88	47.45	41.73	33.30	28.30	27.11	19.30	16.06	26.46	30.69	33.85
Median	36.52	41.88	46.38	41.03	32.70	27.61	25.83	17.94	14.74	23.95	27.56	32.00
Maximum	76.00	83.63	113.36	98.15	76.78	63.96	58.81	66.42	58.39	165.19	203.00	156.95
Minimum	17.13	18.11	17.85	6.99	7.92	7.95	6.76	2.99	2.82	5.17	13.26	13.14
Standard Deviation	8.59	9.12	11.68	13.02	11.44	8.50	8.29	10.60	8.61	12.04	15.19	11.30
LLH	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05
Mean	34.17	37.42	40.49	33.09	28.76	25.16	24.87	18.32	13.53	22.58	27.93	34.21
Median	33.70	36.64	39.54	32.23	27.77	24.32	23.82	17.80	13.72	21.00	27.11	33.40
Maximum	69.05	73.32	89.53	84.98	68.90	55.30	50.61	44.07	40.61	52.67	60.73	75.45
Minimum	15.93	16.11	17.09	3.72	9.28	8.47	9.37	3.08	2.80	4.62	14.92	17.07
Standard Deviation	7.61	7.90	9.85	11.11	9.45	6.90	6.87	6.81	6.69	6.87	6.93	8.07
HLH	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06
Mean	34.51	39.22	44.02	41.59	34.50	29.30	29.76	17.54	17.24	28.98	34.51	35.63
Median	33.73	38.23	42.43	41.47	33.93	28.55	28.82	15.71	16.35	25.81	29.49	33.27
Maximum	74.64	76.15	124.19	112.31	105.89	64.02	62.99	63.52	82.90	251.95	273.26	304.73
Minimum	16.09	18.66	16.96	4.20	6.01	5.02	4.81	2.84	2.85	3.36	11.93	13.21
Standard Deviation	8.00	8.46	11.22	13.78	11.84	8.77	9.06	10.60	10.53	17.56	20.36	14.79
LLH	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06
Mean	31.60	33.92	37.23	33.63	29.60	25.91	26.23	17.32	13.78	23.37	29.34	34.99
Median	31.17	33.26	36.30	33.78	28.71	24.96	25.53	16.67	14.11	22.05	28.47	34.28
Maximum	62.59	64.78	81.51	81.37	84.91	54.42	51.16	46.99	47.14	61.90	61.46	94.84
Minimum	15.38	17.04	14.72	2.99	6.33	5.60	5.19	3.40	2.83	3.86	13.36	16.07
Standard Deviation	7.06	7.35	8.85	11.60	9.53	7.16	6.96	7.42	7.56	7.52	7.20	8.59

4.4.2 Secondary Revenue Results. After the price distributions are generated by AURORA, the prices and corresponding surplus energy or deficit energy amounts are multiplied times the prices to derive estimated surplus sales and power purchase amounts. This occurs in the RiskMod model. The following tables reflect the expected (50th percentile) secondary revenue, power purchases, and net revenue amounts. For FY 2003, actual sales (committed sales) and power purchases (committed purchases) were included in the forecast with transactions completed as of December 31, 2002. The actual sales and purchases will be updated for the final study. Table 4-9 reflects the FY 2003 secondary revenue forecast. For FY 2004-2006, estimated surplus revenues and expenses are reflected in Tables 4-10, 4-11, and 4-12.

Table 4-9: FY 2003 Secondary Revenue Forecast

FY 2003	**Dollars**	**Price**	**AMW**
Committed Sales	$315,995,000	$32.29	1,117
Forecasted Sales	$251,017,000	$39.69	722
Total Sales	$567,012,000	$35.20	1,839
Committed Purchases	$123,866,000	$33.69	420
Forecasted Purchases	$28,351,000	$43.15	75
Total Purchases	$152,217,000	$35.13	495
Net Revenue	$414,795,000	$35.22	1,344

Table 4-10: FY 2004 Secondary Revenue Forecast

FY 2004	**Dollars**	**Price**	**AMW**
Estimated Sales	$541,142,000	$25.32	2,440
Estimated Purchases	$10,572,000	$41.62	29
Net Revenues	$530,570,000	$25.12	2,411

Table 4-11: FY 2005 Secondary Revenue Forecast

FY 2005	**Dollars**	**Price**	**AMW**
Estimated Sales	$558,858,000	$24.64	2,589
Estimated Purchases	$6,278,000	$39.81	18
Net Revenues	$552,580,000	$24.54	2,571

Table 4-12: FY 2006 Secondary Revenue Forecast

FY 2006	Dollars	Price	AMW
Estimated Sales	$533,981,000	$24.17	2,522
Estimated Purchases	$12,443,000	$40.58	35
Net Revenues	$521,538,000	$23.94	2,487

4.4.3 Summary

Due to declining forecasted natural gas prices as well as a return to normal hydroelectric generation levels, BPA expects the weighted average sales price that BPA will receive for surplus power to decline from 2003 levels. However, due to higher amounts of surplus energy to sell into the surplus market, BPA expects to make higher secondary revenues relative to 2003 levels over the FY 2004-2006 timeframe.