RISK ANALYSIS DOCUMENTATION
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RISK ANALYSIS DOCUMENTATION

INTRODUCTION

The Federal Columbia River Power System (FCRPS), operated on behalf of the ratepayers of the Pacific Northwest (PNW) by the Bonneville Power Administration (BPA) and other Federal agencies, faces many uncertainties during the remainder of the Fiscal Year (FY) 2002-2006 rate period. Among these uncertainties are variable hydro conditions and volatile market prices. In order to provide sufficient assurance, *i.e.*, a high probability, that BPA will have made all its payments to the U.S. Treasury by the end of the rate period, BPA performs a Risk Analysis.

In this Risk Analysis, BPA identifies key risks, models their relationships, and then analyzes their impacts on net revenues (revenues less expenses). BPA subsequently evaluates the impact that certain risk mitigation measures have on reducing its net revenue risk so that BPA can develop rates that cover all its costs and provide sufficient assurance, *i.e.*, a high probability, that BPA will have made all its payments to the U.S. Treasury by the end of the rate period. To accomplish this task, it is necessary to quantify and then mitigate BPA's key operating risks. The first step in this process is the Risk Analysis.

The Risk Analysis focuses upon operating risks - variations in economic conditions, load, and generation resource capability – and their impact on BPA's revenues and expenses. These operating risks are modeled in RiskMod. RiskMod is a computer simulation model that calculates firm and surplus energy revenues, balancing power purchase expenses, Fish Cost Contingency Fund (FCCF) credits, and 4(h)(10)(C) credits under various load, resource, and market price conditions to estimate BPA's operational net revenue risk.

The output from RiskMod yields a distribution of net revenue deviations that are input into the ToolKit Model. The ToolKit Model uses the net revenue data to test the effectiveness of implementing various risk mitigation measures in order to provide sufficient assurance, *i.e.*, a high probability, that BPA will have made all its payments to the U.S. Treasury by the end of the rate period.

RiskMod uses the simulation methodology in the @RISK computer software package to assess the impacts of a distribution of risk factors on net revenues. RiskMod quantifies the operating risks associated with loads and resources performance for California, the PNW, and the Federal system, in addition to those risks associated with natural gas prices.

This chapter describes the operation of RiskMod and its quantification of operating risks. Chapter 7 of this Study Documentation describes how the results of the Risk Analysis are used in the ToolKit Model.

6. OPERATIONAL RISK ANALYSIS MODEL (RISKMOD)

6.1 RiskMod

The RiskMod Model is comprised of a set of risk simulation models collectively referred to as RiskSim; a set of computer programs that manages data referred to as Data Manager; and RevSim, a model that calculates net revenues. Variations in monthly loads, resources, and natural gas prices are simulated in RiskSim. Monthly electricity prices for the simulated loads, resources, and natural gas prices are estimated by the AURORA Model. *See* Chapter 4 of the Study. The Data Manager facilitates the format and movement of data that flow to and from RiskSim, RevSim, and AURORA. RevSim uses risk data from RiskSim, electricity prices from AURORA, load and resource data from the Loads and Resources Study (*see* Chapter 2 of the Study), various revenues and rates from the Revenue Forecast (s*ee* Chapter 5 of the Study), and expenses from the Revenue Recovery (*see* Chapter 3 of the Study) to estimate net revenues.

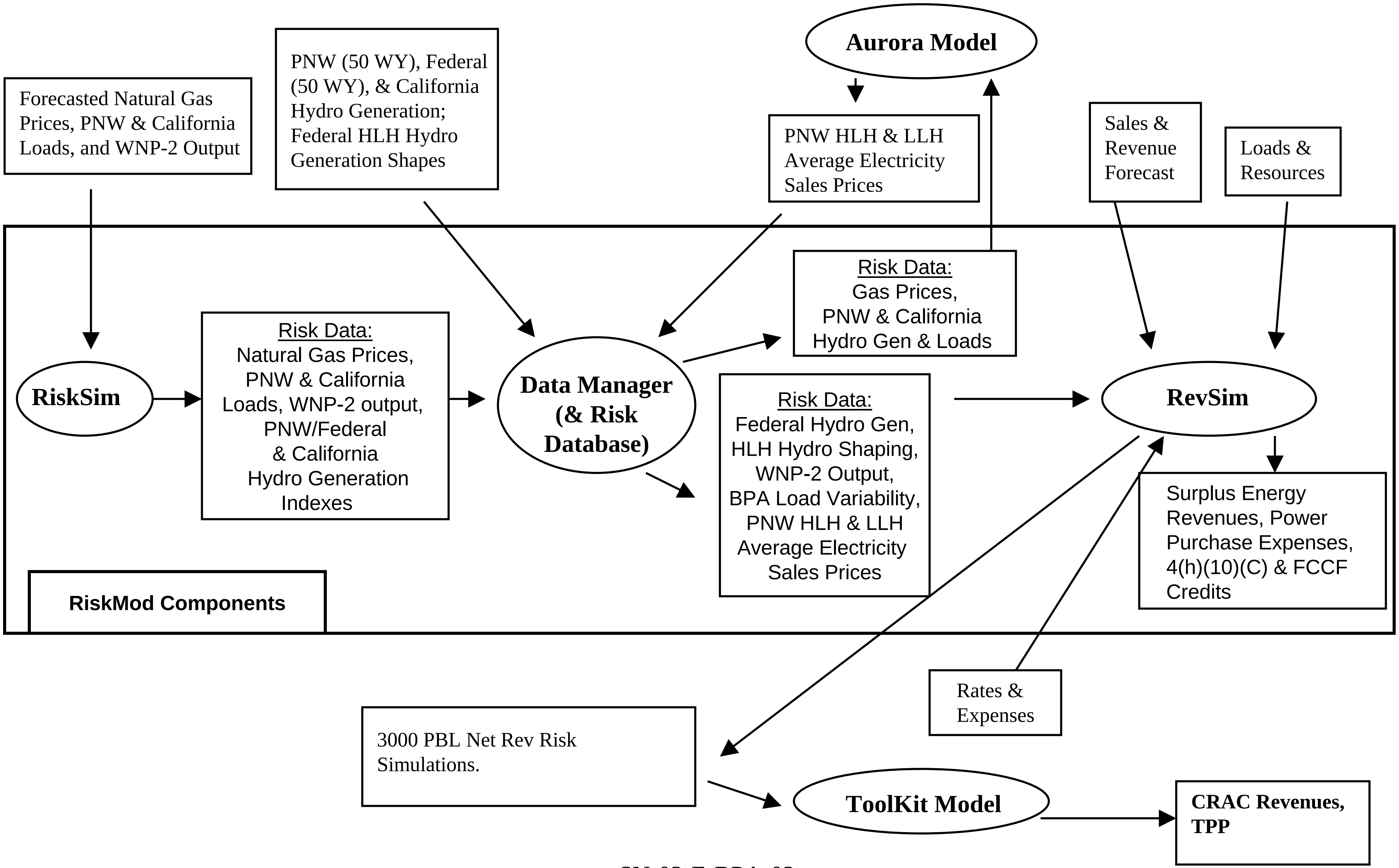
Annual average surplus energy revenues, purchased power expenses, section 4(h)(10)(C) credits, and FCCF credits calculated by RevSim are used in the Revenue Forecast. Net revenues estimated for each simulation by RevSim are input into the ToolKit Model to calculate CRAC revenues. The processes and interactions between RiskMod and other models and studies are depicted in Graph 6.1.

6.2 Risk Simulation Models (RiskSim)

To quantify the effects of operational risks, BPA has developed risk simulation models that combine logic, econometrics, and probability distributions to quantify the ordinary operational risks that BPA faces. Econometric modeling techniques are used to capture the dependency of values through time. Parameters for the probability distributions are developed from historical data. The values sampled from each probability distribution reflect their relative likelihood of occurrence and are deviations from the base case values used in the AURORA Model and the Revenue Forecast. *See* Chapters 4 and 5 of the Study.

The monthly output from these risk simulation models were accumulated into a computer file to form a risk database which contains values lower than, higher than, or equal to the forecasted values used in the AURORA Model and the Revenue Forecast. *Id.* Loads, resources, and natural gas price risk data for each simulation were input into the AURORA Model to estimate monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) electricity prices. The prices estimated by AURORA were then downloaded into the risk database and a consistent set of loads, resources, and electricity prices were used to calculate net revenues in RevSim. The risk

Graph 6-1: RiskMod Risk Analysis Information Flow



models are run for 3000 simulations to produce monthly risk data for FY 2003-2006 for this rate filing.

6.3 @RISK Computer Software

The risk simulation models developed to quantify operational risks were developed in the @RISK computer software package. This software is an add-in computer package to Microsoft Excel and is available from Palisade Corporation. @RISK allows statisticians to develop models incorporating uncertainty in a spreadsheet environment. Uncertainty is incorporated by specifying the type of probability distribution that best reflects the risk, providing the necessary parameters required for developing the probability distribution, and letting @RISK sample values from the probability distributions based on the parameters provided. The values sampled from the probability distributions reflect their relative likelihood of occurrence. The parameters required for appropriately capturing risk are not developed in @RISK, but are developed in analyses external to @RISK.

6.4 Operational Risk Factors

In the course of doing business, BPA manages risks that are unique to operating a hydro system as large as the FCRPS. The variation in hydro generation due to the volume of water supply from one year to the next can be substantial. BPA also faces other traditional operational risks that increase BPA's risk exposure, including the following: load variability due to load growth and weather; nuclear plant (CGS) performance; and variability in electricity prices due to load, resource, and natural gas price variability. The following is a discussion of the major risk factors included in RiskMod.

6.5 PNW and Federal Hydro Generation Risk Factors

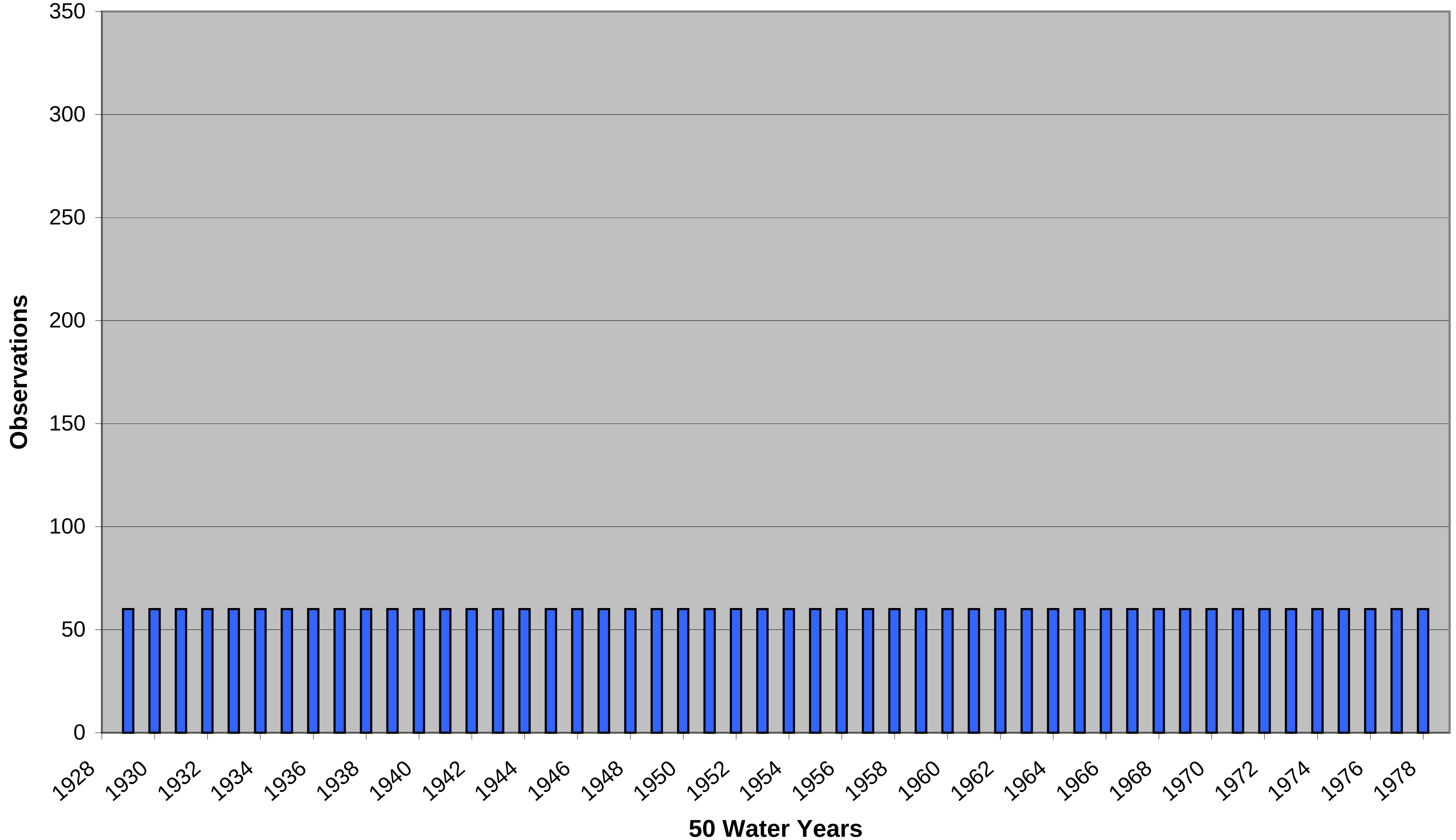
Federal hydro generation risk was incorporated into RiskMod to account for the impact that various Federal hydro generation levels and HLH and LLH hydro generation shaping capability have on the quantity of energy that BPA has to buy and sell during HLH and LLH periods. PNW hydro generation risk is incorporated into the Risk Analysis to account for the impact that various PNW hydro generation levels have on monthly HLH and LLH electricity prices estimated by the AURORA Model. PNW and Federal hydro generation risk are incorporated into the Risk Analysis in different ways for FY 2004-2006 than FY 2003.

6.5.1 Modeling FY 2004-2006 Hydro Risk. For FY 2004-2006, Federal and PNW hydro generation risk were accounted for in the Risk Analysis by inputting into RiskMod and AURORA monthly Federal and PNW hydro generation data for each of the historical 50 water years (1929-1978) developed from running a continuous study in the HydroSim Model. *See* Hydro Regulation component of the Loads and Resources Study (Chapter 2 of the Study), regarding HydroSim, continuous study, and 50 water years. The term "continuous study" refers to calculating hydro generation data sequentially over all 600 months of the 50 water year period. Developing hydro generation data in such a continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 50 water year period. For FY 2004, additional hydro generation adjustments were made to each of the 50 water year data from the continuous study for FY 2004 to reflect the outlook that storage levels on the Federal Columbia River Power System are not expected to refill in FY 2003. *See* Chapter 2 of the Study, regarding FY 2004 hydro generation adjustments.

A consistent set of monthly Federal and PNW hydro generation data for hydro operations in FY 2004 are randomly sampled, by water year, from tables containing hydro generation values for each of the 50 water years for 12 months of the year (50 X 12 tables). The 50 X 12 tables were derived from 50 X 14 tables by averaging hydro generation data for the first and second half of April and August. The ability of the FCRPS to shape average monthly hydro generation into HLH hydro generation, for each water year, is incorporated into RiskMod by selecting from a 50 X 12 table of HLH ratios produced by the Hourly Operating and Scheduling Simulator (HOSS) Model. *See* Chapter 2 of the Study, regarding HOSS. The HLH ratios used are based on the water year sampled for hydro generation and these ratios reflect the portion of average energy that can be shaped into heavy load hours. Given the HLH ratios from HOSS, LLH ratios are calculated in RevSim. *See* Chapter 2 of this Study Documentation, for tables of FY 2004-2006 Federal and PNW hydro generation data, along with HLH ratios from HOSS and hydro generation adjustments for FY 2004.

6.5.2 Sampling FY 2004 – FY 2006 Hydro Generation. Federal and PNW hydro generation variability is modeled in the Risk Analysis by randomly sampling, in the @RISK computer software, each of the 50 water years (1929-1978) and using the associated hydro generation data in the same continuous manner that the data are developed by HydroSim when performing a continuous study. The random selection of the initial water year (for FY 2004) is accomplished by sampling real values ranging from 1929-1978 from a uniform probability distribution in a risk simulation model and subsequently converting each number to the nearest integer values (whole numbers). Given the initial water year, the corresponding monthly Federal and PNW hydro generation data and the HOSS HLH hydro generation ratios for that water year are selected for the first year (FY 2004). The uniform probability distribution was selected for modeling hydro generation risk because it appropriately assigns equal probability to each of the 50 water years being sampled. Graph 6.2 reports the number of times that each of the 50 water years were sampled from a uniform probability distribution for 3000 simulations. As shown in this graph, each of the 50 water years was sampled 60 times.

Graph 6.2: Number o-Times PNW and Federal Hydro Generation for the 50 Water Years were Sampled for FY's 2004-06 Based on 3000 Sampled Values



After an initial water year is selected for FY 2004 for a given simulation, hydro generation data for a sequential set of three water years, starting with the water year selected for FY 2004, are selected from water years 1929-1978. When the end of the 50 water years is reached (at the end of water year 1978), monthly hydro generation data for water year 1929 is subsequently used. Thus, if a simulation starts with water year 1977, the simulation will use water years 1977 and 1978, as well as water year 1929, for a total of three sequential water years. This approach was used so that each of the 50 water years was sampled an equal number of times. Using Federal and PNW hydro generation data in this continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 50 water years of hydro generation data.

6.5.3 Modeling FY 2003 Hydro Risk. For FY 2003, Federal and PNW hydro generation risk were accounted for in the Risk Analysis by inputting into RiskMod and AURORA monthly Federal and PNW hydro generation data for each of the historical 50 water years (1929-1978) developed from running a refill study in the HydroSim Model. *See* Hydro Regulation component of the Loads and Resources Study (Chapter 2 of the Study), regarding HydroSim, refill study, and 50 water years. The term “refill study” refers to calculating hydro generation data based on updated information about reservoir levels. Developing hydro generation data in such this manner provides more accurate data regarding near-term hydro generation risk.

Consistent sets of monthly Federal and PNW hydro generation data for hydro operations in FY 2003 from the refill study are sampled from tables containing hydro generation values for each of the 50 water years for 12 months of the year (50 X 12 tables). The 50 X 12 tables were derived from 50 X 14 tables by averaging hydro generation data for the first and second half of April and August. The ability of the FCRPS to shape average monthly hydro generation into HLH hydro generation, for each water year, is incorporated into RiskMod by selecting from a 50 X 12 table of HLH ratios produced by the HOSS Model. The HLH ratios used are based on the water year sampled for hydro generation and these ratios reflect the portion of average energy that can be shaped into heavy load hours. Given the HLH ratios from HOSS, LLH ratios are calculated in RevSim. *See* Chapter 2 of this Study Documentation, for tables of FY 2003 Federal and PNW hydro generation data, along with HLH ratios from HOSS.

For FY 2003, the hydro generation data for each of the 50 water years were probability-weighted in RiskMod so that the sampled hydro generation data yielded results consistent with the 2003 January-July runoff volume forecast (February Early Bird) of 74.8 million acre feet (MAF) by the Northwest River Forecast Center. *See* Hydro Regulation component of the Loads and Resources Study (Chapter 2 of the Study) and Chapter 2 of this Study Documentation, for tables of FY 2003 Federal and PNW hydro generation data, along with the associated probability weights.

6.5.4 Sampling FY 2003 Hydro Generation. FY 2003 Federal and PNW hydro generation variability is modeled in the Risk Analysis using the @Risk computer software. This task was accomplished by developing a discrete probability distribution in @Risk that reflected the probability of the Jan-Jul streamflow amounts (in MAF) for each of the 50 water years occurring in FY 2003, consistent with the 2003 January-July runoff volume forecast (February Early Bird) of 74.8 million acre feet (MAF) by the Northwest River Forecast Center. The probabilities of various hydro generation amounts was determined by sampling values from 1929 to 1978 (50 WY) at their respective probability weights from the discrete probability distribution and selecting the corresponding monthly Federal and PNW hydro generation data and the HOSS HLH hydro generation ratios for each water year. Under this approach, several of the water years had probability weights of zero.

The discrete probability distribution was selected for modeling hydro generation risk for FY 2003 because it easily and accurately accommodates the exact probability weights associated with the 2003 January-July runoff volume forecast. Graph 6.3 reports the number of times that each of the 50 water years were sampled for FY 2003 from the discrete probability distribution for 3000 simulations.

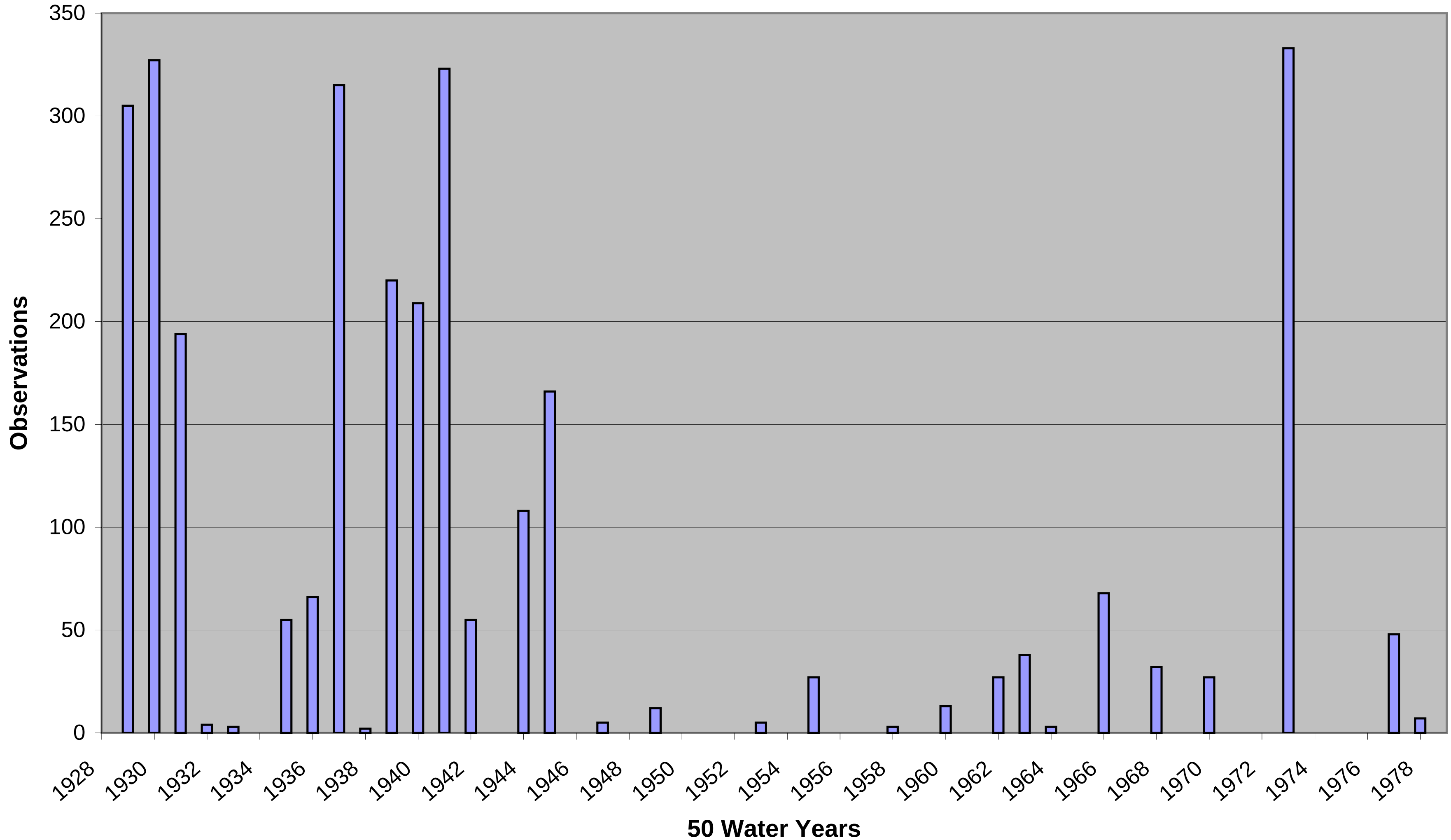
6.5.5 Use of PNW Hydro Generation Risk in AURORA. Variability in PNW hydro generation is incorporated into the AURORA Model by calculating (via the Data Manager), from monthly PNW hydro generation data for each of the 50 water years, PNW annual energy to capacity ratios (using the total capacity value for all of the PNW in the AURORA Model), calculating PNW monthly to annual hydro generation ratios, and inputting this data into the AURORA Model. *See* Chapter 4 of the Study, regarding the AURORA Model. These sets of ratios are used by AURORA to calculate first the annual, and then the monthly hydro generation for each of the three regions (Oregon/Washington, Idaho, Montana) for the PNW in AURORA. This process results in the sum of the hydro generation for the three regions in AURORA being equal to the PNW hydro generation.

6.6 PNW and BPA Loads Risk Factors

PNW load uncertainty is incorporated into the Risk Analysis to account for the impact that PNW load uncertainty has on monthly HLH and LLH electricity prices--which impacts BPA's surplus energy revenues and power purchase expenses. This impact is accounted for by inputting into the AURORA Model various PNW load values and having it estimate the associated HLH and LLH electricity prices. *See* Chapter 4 of the Study, regarding the AURORA Model.

BPA load uncertainty is incorporated into the Risk Analysis to account for the impact that monthly PF load variability has on PF revenues, surplus energy revenues, and power purchase expenses. This impact is accounted for by inputting into RevSim various monthly load variability values that modify the amount of PF loads served by BPA.

Graph 6.3: Number of Times PNW and Federal Hydro Generation for the 50 Water Years were Sampled Using WY Weights for FY 2003 Based on 3000 Sampled Values



6.6.1 PNW and BPA Load Variability. Only monthly PNW load variability is modeled in the PNW Load Risk Model. BPA monthly load variability is derived such that the same percentage changes in PNW loads are used to quantify BPA load variability.

The PNW Load Risk Model is designed to incorporate forecasted monthly load data from the AURORA Model such that, when no risk is being simulated, the forecasted monthly loads match the sum of the forecasted loads for the three regions (Oregon/Washington, Idaho, and Montana) that comprise the PNW in the AURORA Model. This process results in the simulated loads reflecting variability in loads relative to the forecasted loads used in AURORA. *See* Chapter 4 of the Study, regarding the AURORA Model.

Variability in monthly BPA loads is derived from simulated PNW loads by dividing simulated loads by forecasted PNW loads to obtain ratios that are values relative to 1.00 (when the simulated loads equal the forecasted loads). For instance, a value of 1.05 translates into a 5 percent increase in PNW loads and into a 5 percent increase in BPA loads.

PNW (and indirectly BPA) load variability is modeled in the PNW Load Risk Model such that annual load growth variability and monthly load swings due to weather conditions are both accounted for in one PNW load variability factor. This task is accomplished by first simulating annual load growth for years from 2003-2006 and then, subsequently, simulating the impact of monthly load swings due to weather on the simulated monthly loads that include load growth.

6.6.2 PNW and BPA Annual Load Growth Risk. PNW (and indirectly BPA) annual load growth risk is modeled using a random-walk technique. This quantitative method simulates various annual average load levels through time with the starting point for simulating annual average load in a given year being the annual average load level from the previous year. Under this method, simulated annual average loads randomly increase and decrease through time from the annual average load level of the prior year with the results including outcomes that represent periods of strong load growth, weak load growth, and vacillating positive and negative load growth.

Input data from the AURORA Model used in the PNW Load Risk Model are the following: (1) annual average 2002 PNW load; (2) forecasted annual load growth for 2003-2006; and (3) monthly load shaping factors (values relative to 1.00) that were derived for use in AURORA by dividing historical monthly loads by historical annual average loads. *See* Chapter 4 of the Study, regarding the AURORA Model. Inputting the data used by the AURORA Model allows the PNW Load Risk Model to replicate the forecasted monthly PNW loads in AURORA.

Load growth variability is incorporated into the PNW Load Risk Model by sampling values from standard normal distributions (normal distributions with a mean of zero and a standard deviation of one) in @RISK, multiplying the sampled values by an annual load growth standard deviation, and adding the simulated positive and negative values to the annual load level of the prior year. The values sampled from the standard normal distribution are in terms of the number of positive or negative standard deviations. Variability in monthly loads due to load growth risk is derived by multiplying variable annual loads by deterministic monthly load shape factors. The annual load growth standard deviation used in the PNW Load Risk Model is 2.4 percent, which was derived from WSCC load data from 1982-1998 for the Northwest Power Pool Area. The source of this data was a publication by the WSCC titled, 10-Year Coordinated Plan Summary 1999-2008, Planning and Operation for Electric System Reliability, Western Systems Coordinating Council, October 1999, at 60. The historical WSCC load data and the annual load growth standard deviation calculations by BPA are reported in Tables 6-1 and 6-2.

6.6.3 PNW and BPA Load Risk Due to Weather Conditions. Monthly PNW (and indirectly BPA) load variability due to weather conditions is quantified by first sampling values from

Table 6.1: Historical WSCC Load Data (Calendar Year)

	Thousands of GWh						aMW				
Year	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WSCC Total		Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WSCC Total
1982	234.8	31.28	42.72	188.0	496.8		26,804	3,571	4,877	21,461	56,712
1983	235.3	31.81	44.08	188.0	499.2		26,861	3,631	5,032	21,461	56,985
1984	250.9	33.09	46.70	205.2	535.9		28,642	3,777	5,331	23,425	61,175
1985	257.3	35.40	50.64	209.7	553.0		29,372	4,041	5,781	23,938	63,132
1986	253.4	34.82	51.46	216.3	556.0		28,927	3,975	5,874	24,692	63,468
1987	262.4	35.36	**63.42**	**214.6**	575.8		29,954	4,037	7,240	24,498	65,728
1988	280.2	37.03	**67.48**	**223.3**	608.0		31,986	4,227	7,703	25,491	69,408
1989	291.4	38.02	**71.25**	**229.1**	629.8		33,265	4,340	8,134	26,153	71,892
1990	301.1	38.49	**74.54**	**236.7**	650.8		34,372	4,394	8,509	27,021	74,296
1991	305.2	38.44	**75.71**	**230.6**	650.0		34,840	4,388	8,643	26,324	74,195
1992	307.6	39.99	**77.90**	**236.7**	662.2		35,114	4,565	8,893	27,021	75,592
1993	312.8	40.55	**80.42**	**235.6**	669.4		35,708	4,629	9,180	26,895	76,412
1994	316.3	42.05	**86.05**	**243.7**	688.1		36,107	4,800	9,823	27,820	78,550
1995	318.3	43.42	**87.66**	**240.5**	689.9		36,336	4,957	10,007	27,454	78,753
1996	334.2	43.92	**94.72**	**248.7**	721.5		38,151	5,014	10,813	28,390	82,368
1997	332.1	47.08	**98.53**	**256.9**	734.6		37,911	5,374	11,248	29,326	83,860
1998	342.9	48.07	**97.36**	**254.6**	742.9		39,144	5,487	11,114	29,064	84,809

Note: For the reason describe below, California load growth variability was calculated using data from 1987-98.

Prior to 1997, the Southern Nevada reporting-area data were included in the California sub-area data.
The Arizona-New Mexico-Southern Nevada Power Area and California-Mexico Power Area data, prior to 1987,
have not been adjusted for the Southern Nevada reporting-area change

Table 6.2: PNW and California Annual Load Variability Computations

Year	Northwest Power Pool Area	Change From Prior Year 1982-98		Year	California Mexico Power Area	Change From Prior Year 1987 98
1982	26,804			1987	24,498	
1983	26,861	0.002		1988	25,491	0.041
1984	28,642	0.066		1989	26,153	0.026
1985	29,372	0.026		1990	27,021	0.033
1986	28,927	-0.015		1991	26,324	-0.026
1987	29,954	0.036		1992	27,021	0.026
1988	31,986	0.068		1993	26,895	-0.005
1989	33,265	0.040		1994	27,820	0.034
1990	34,372	0.033		1995	27,454	-0.013
1991	34,840	0.014		1996	28,390	0.034
1992	35,114	0.008		1997	29,326	0.033
1993	35,708	0.017		1998	29,064	-0.009
1994	36,107	0.011				
1995	36,336	0.006				
1996	38,151	0.050				
1997	37,911	-0.006				
1998	39,144	0.033				
	Avg	**0.024**			**Avg**	**0.016**
	StDev	**0.024**			**StDev**	**0.024**
	Min	**-0.015**			**Min**	**-0.026**
	Max	**0.068**			**Max**	**0.041**

standard normal distributions in @RISK, then multiplying the sampled values by monthly PNW load standard deviations, and finally adding the resulting positive and negative values to the simulated loads after load growth.

The monthly PNW load standard deviations are derived from utility-specific, monthly historical daily load standard deviations and 2005 forecasted loads for PNW utilities used as input data in PMDAM when performing the MCA in the 1996 rate case (*see* MCA Study Documentation, WP-96-FS-BPA-04A, Part 2 of 2; pages 305 and 257). This derivation is accomplished by calculating composite, load-weighted, monthly load standard deviations from utility-specific, daily load standard deviations (for the 12 months of the year) and annual average load data.

6.6.4 Derivation of PNW/BPA Monthly Load Variability Due to Weather Conditions. BPA assumes, for rate setting purposes, that daily weather patterns over the course of a month are independent and that each day of a given month has the same daily load standard deviation. Accordingly, BPA used the following statistical equation to derive monthly load standard deviations from daily load standard deviations for each month. The statistical equation for calculating the standard deviation for the average of "n" number of independent random variables is the following:

$$\sigma_{\bar{x}} = \frac{\sigma_x}{\sqrt{n}}$$

Where:

$\underline{\sigma_x}$ is the standard deviation for all independent random variables

$\overline{}$
n is the number of independent random variables

In the case of BPA's analysis, the number of independent random variables is the number of days in a month and the standard deviation for all the independent random variables is the daily load standard deviations for each month. The PNW monthly load standard deviations for each month are derived by inserting values for the number of days in each month and the daily load standard deviations for each month into the equation above.

Table 6-3 contains the calculations performed to derive PNW monthly load standard deviations from daily load standard deviations for each month. These monthly load standard deviations are input into the PNW Load Risk Model to quantify monthly load variability due to weather. Table 6.4 contains a copy of the PNW Load Risk Model. Results from this risk model are shown in Graph 6.4 for the 5^{th}, 50^{th}, and 95^{th} percentiles.

6.6.5 Use of Simulated PNW Loads in AURORA. The HLH and LLH electricity prices associated with changes in PNW monthly loads are estimated in the AURORA Model by inputting PNW load data simulated by the PNW Load Risk Model. This process involves calculating (via the Data Manager) monthly load ratios (monthly loads divided by the annual average loads) from monthly and annual load data simulated by the PNW Load Risk Model and then inputting the monthly ratios and annual average energy loads into the AURORA Model for each simulation. *See* Chapter 4 of the Study, regarding the AURORA Model. These data are input into AURORA to calculate annual and monthly loads for each of the three PNW regions (Oregon/Washington, Idaho, and Montana) in AURORA. This process results in the sum of the loads for the three PNW regions in AURORA being equal to the simulated PNW loads from the PNW Load Risk Model.

Table 6.3: Derivation of Load-Weighted, Monthly Load Standard Deviations for PNW

PNW

		Loads CY 2005	Daily Load Standard Deviations											
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PGE	PGEFRM	2057	0.10	0.10	0.08	0.09	0.08	0.08	0.11	0.08	0.09	0.09	0.09	0.10
PP&L	PPLFRM	2462	0.12	0.13	0.10	0.13	0.12	0.10	0.16	0.11	0.12	0.12	0.12	0.13
OIOU	OIOFRM	2772	0.07	0.09	0.05	0.07	0.06	0.07	0.08	0.06	0.07	0.06	0.07	0.07
GPUB	GPUFRM	2827	0.08	0.08	0.07	0.08	0.09	0.07	0.08	0.07	0.08	0.09	0.08	0.09
BPA	BPAFRM	3740	0.09	0.09	0.06	0.07	0.06	0.05	0.06	0.06	0.07	0.08	0.09	0.10
OIOU	PSPL	2673	0.09	0.10	0.07	0.10	0.08	0.06	0.07	0.06	0.07	0.09	0.09	0.09
GPUB	COPOSN	1499	0.09	0.08	0.06	0.08	0.08	0.08	0.14	0.04	0.07	0.07	0.07	0.10
BPA	DSIFRM	1061	0.02	0.01	0.01	0.02	0.01	0.02	0.01	0.01	0.05	0.01	0.01	0.01
BPA	DSI2Q	2122	0.02	0.01	0.01	0.02	0.01	0.02	0.01	0.01	0.05	0.01	0.01	0.01
BPA	DSINFM	0	0.02	0.01	0.01	0.02	0.01	0.02	0.01	0.01	0.05	0.01	0.01	0.01
Total PNW		**21213**												

		Loads CY 2005	Daily Load Variances											
			Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
PGE	PGEFRM	2057	0.0100	0.0100	0.0064	0.0081	0.0064	0.0064	0.0121	0.0064	0.0081	0.0081	0.0081	0.0100
PP&L	PPLFRM	2462	0.0144	0.0169	0.0100	0.0169	0.0144	0.0100	0.0256	0.0121	0.0144	0.0144	0.0144	0.0169
OIOU	OIOFRM	2772	0.0049	0.0081	0.0025	0.0049	0.0036	0.0049	0.0064	0.0036	0.0049	0.0036	0.0049	0.0049
GPUB	GPUFRM	2827	0.0064	0.0064	0.0049	0.0064	0.0081	0.0049	0.0064	0.0049	0.0064	0.0081	0.0064	0.0081
BPA	BPAFRM	3740	0.0081	0.0081	0.0036	0.0049	0.0036	0.0025	0.0036	0.0036	0.0049	0.0064	0.0081	0.0100
OIOU	PSPL	2673	0.0081	0.0100	0.0049	0.0100	0.0064	0.0036	0.0049	0.0036	0.0049	0.0081	0.0081	0.0081
GPUB	COPOSN	1499	0.0081	0.0064	0.0036	0.0064	0.0064	0.0064	0.0196	0.0016	0.0049	0.0049	0.0049	0.0100
BPA	DSIFRM	1061	0.0004	0.0001	0.0001	0.0004	0.0001	0.0004	0.0001	0.0001	0.0025	0.0001	0.0001	0.0001
BPA	DSI2Q	2122	0.0004	0.0001	0.0001	0.0004	0.0001	0.0004	0.0001	0.0001	0.0025	0.0001	0.0001	0.0001
BPA	DSINFM	0	0.0004	0.0001	0.0001	0.0004	0.0001	0.0004	0.0001	0.0001	0.0025	0.0001	0.0001	0.0001
Total PNW		**21213**												
Number of Days Per Month			31	28	31	30	31	30	31	31	30	31	30	31
Weighted Daily Load Variances			**0.0072**	**0.0080**	**0.0043**	**0.0069**	**0.0058**	**0.0045**	**0.0085**	**0.0044**	**0.0062**	**0.0065**	**0.0068**	**0.0082**
Weighted Daily Load Standard Deviations			**0.0849**	**0.0894**	**0.0654**	**0.0829**	**0.0758**	**0.0669**	**0.0921**	**0.0661**	**0.0784**	**0.0807**	**0.0822**	**0.0903**
Monthly Load Standard Deviations			**0.0153**	**0.0169**	**0.0118**	**0.0151**	**0.0136**	**0.0122**	**0.0165**	**0.0119**	**0.0143**	**0.0145**	**0.0150**	**0.0162**

Table 6.4: PNW Load --sk Model for 2003 - 2006

PNW Load Variability

PNW Load Growth Uncertainty:

Forecasted Calendar Year (2002) Annual Average PNW Loads	21,221
Forecasted PNW Load Growth for 2002; Source: Aurora	0.00%
Forecasted PNW Load Growth for 2003; Source: Aurora	1.70%
Forecasted PNW Load Growth for 2004; Source: Aurora	1.73%
Forecasted PNW Load Growth for 2005; Source: Aurora	1.97%
Forecasted PNW Load Growth for 2006; Source: Aurora	1.80%
Load Growth Std Dev; Source: PMDAM	2.40%

Estimated Base Case Loads		*Std Normal Dist*
CY 2002	21,221	*0.0*
CY 2003	21,582	*0.0*
CY 2004	21,955	*0.0*
CY 2005	22,388	*0.0*
CY 2006	22,791	*0.0*

Load Growth Dev from any specified forecasted load level	
CY 2002	*21221*
CY 2003	*21582*
CY 2004	*21955*
CY 2005	*22388*
CY 2006	*22791*

PNW Load Variability Due to Load Growth Uncertainty

Calendar Year 2003

	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	Average
Average Annual PNW Loads (Average Energy in aMW)	21582	21582	21582	21582	21582	21582	21582	21582	21582	21582	21582	21582	
PNW Monthly Load Shapes (Source: AURORA)	1.138	1.108	1.010	0.940	0.921	0.935	0.959	0.942	0.911	0.940	1.063	1.139	
Simulated Monthly PNW Loads (Average Energy in aMW)	24565	23909	21802	20290	19885	20174	20687	20320	19667	20280	22951	24572	21,592 aMW

PNW Load Variability Due to Load Growth and Weather Uncertainty

	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	
PNW Loads after Load Growth (Average Energy in aMW)	24565	23909	21802	20290	19885	20174	20687	20320	19667	20280	22951	24572	21,592 aMW
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations in PMDAM)	1.53%	1.69%	1.18%	1.51%	1.36%	1.22%	1.65%	1.19%	1.43%	1.45%	1.50%	1.62%	
Random PNW Loads (Average Energy in aMW)	*24,565*	*23,909*	*21,802*	*20,290*	*19,885*	*20,174*	*20,687*	*20,320*	*19,667*	*20,280*	*22,951*	*24,572*	21,592 aMW

Table 6.4: PNW Load Risk Model for 2004 (Continued)

PNW Load Variability

PNW Load Variability Due to Load Growth Uncertainty

	Calendar Year 2004												
	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	Average
Average Annual PNW Loads (Average Energy in aMW)	21955	21955	21955	21955	21955	21955	21955	21955	21955	21955	21955	21955	
PNW Monthly Load Shapes (Source: AURORA)	**1.138**	**1.108**	**1.010**	**0.940**	**0.921**	**0.935**	**0.959**	**0.942**	**0.911**	**0.940**	**1.063**	**1.139**	
Simulated Monthly PNW Loads (Average Energy in aMW)	24990	24323	22179	20641	20229	20523	21045	20671	20007	20630	23348	24997	**21,965 aMW**

PNW Load Variability Due to Load Growth and Weather Uncertainty

	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	
PNW Loads after Load Growth (Average Energy in aMW)	24990	24323	22179	20641	20229	20523	21045	20671	20007	20630	23348	24997	**21,965 aMW**
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations ir	1.53%	1.69%	1.18%	1.51%	1.36%	1.22%	1.65%	1.19%	1.43%	1.45%	1.50%	1.62%	
Random PNW Loads (Average Energy in aMW)	***24,990***	***24,323***	***22,179***	***20,641***	***20,229***	***20,523***	***21,045***	***20,671***	***20,007***	***20,630***	***23,348***	***24,997***	**21,965 aMW**

Table 6.4: PNW Load Risk Model for 2005 (Continued)

PNW Load Variability

PNW Load Variability Due to Load Growth Uncertainty

Calendar Year 2005	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	Average
Average Annual PNW Loads (Average Energy in aMW)	22388	22388	22388	22388	22388	22388	22388	22388	22388	22388	22388	22388	
PNW Monthly Load Shapes (Source: AURORA)	**1.138**	**1.108**	**1.010**	**0.940**	**0.921**	**0.935**	**0.959**	**0.942**	**0.911**	**0.940**	**1.063**	**1.139**	
Simulated Monthly PNW Loads (Average Energy in aMW)	25482	24802	22616	21048	20627	20928	21460	21079	20401	21037	23808	25490	**22,398 aMW**

PNW Load Variability Due to Load Growth and Weather Uncertainty

	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	
PNW Loads after Load Growth (Average Energy in aMW)	25482	24802	22616	21048	20627	20928	21460	21079	20401	21037	23808	25490	**22,398 aMW**
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations ir	1.53%	1.69%	1.18%	1.51%	1.36%	1.22%	1.65%	1.19%	1.43%	1.45%	1.50%	1.62%	
Random PNW Loads (Average Energy in aMW)	***25,482***	***24,802***	***22,616***	***21,048***	***20,627***	***20,928***	***21,460***	***21,079***	***20,401***	***21,037***	***23,808***	***25,490***	**22,398 aMW**

Table 6.4: PNW Load Risk Model for 2006 (Continued)

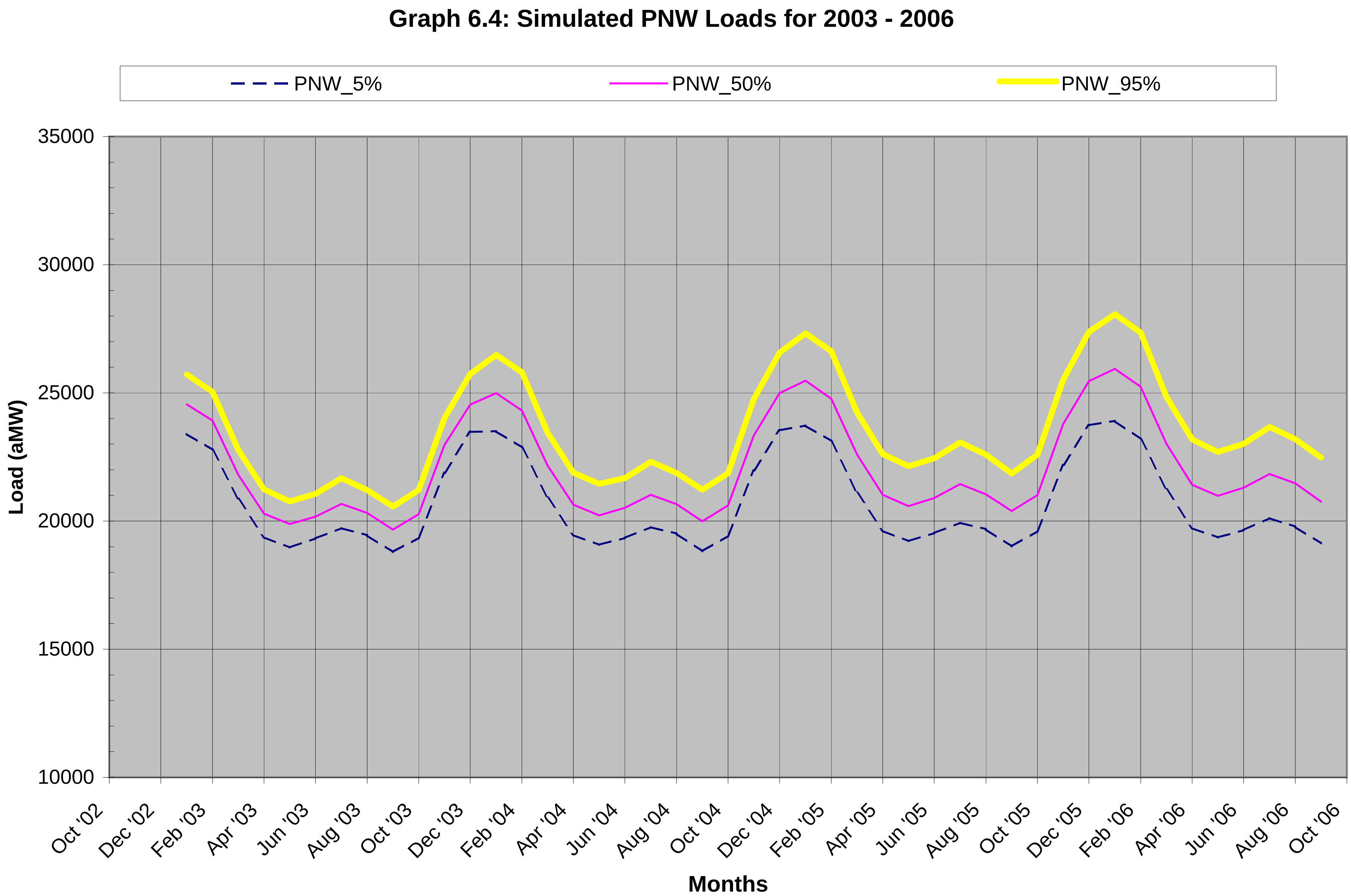
PNW Load Variability

PNW Load Variability Due to Load Growth Uncertainty

Calendar Year 2006	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	Average
Average Annual PNW Loads (Average Energy in aMW)	22791	22791	22791	22791	22791	22791	22791	22791	22791	22791	22791	22791	
PNW Monthly Load Shapes (Source: AURORA)	**1.138**	**1.108**	**1.010**	**0.940**	**0.921**	**0.935**	**0.959**	**0.942**	**0.911**	**0.940**	**1.063**	**1.139**	
Simulated Monthly PNW Loads (Average Energy in aMW)	25941	25248	23024	21426	20999	21304	21846	21458	20768	21415	24236	25948	**22,801 aMW**

PNW Load Variability Due to Load Growth and Weather Uncertainty

	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	
PNW Loads after Load Growth (Average Energy in aMW)	25941	25248	23024	21426	20999	21304	21846	21458	20768	21415	24236	25948	**22,801 aMW**
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations i	1.53%	1.69%	1.18%	1.51%	1.36%	1.22%	1.65%	1.19%	1.43%	1.45%	1.50%	1.62%	
Random PNW Loads (Average Energy in aMW)	***25,941***	***25,248***	***23,024***	***21,426***	***20,999***	***21,304***	***21,846***	***21,458***	***20,768***	***21,415***	***24,236***	***25,948***	**22,801 aMW**


Graph 6.4: Simulated PNW Loads for 2003 - 2006
PNW_5%
PNW_50%
PNW_95%
Load (aMW)
35000
30000
25000
20000
15000
10000
Oct '02
Dec '02
Feb '03
Apr '03
Jun '03
Aug '03
Oct '03
Dec '03
Feb '04
Apr '04
Jun '04
Aug '04
Oct '04
Dec '04
Feb '05
Apr '05
Jun '05
Aug '05
Oct '05
Dec '05
Feb '06
Apr '06
Jun '06
Aug '06
Oct '06
Months

6.7 California Hydro Generation Risk Factor

California hydro generation risk is incorporated into the Risk Analysis to account for the impact that variability in California hydro generation has on monthly HLH and LLH electricity prices--which impacts BPA's surplus energy revenues and power purchase expenses.

6.7.1 Modeling Hydro Risk. California hydro generation risk for FY 2003-2006 is incorporated into the Risk Analysis by sampling 18 years of historical monthly California hydro generation data and estimating the associated monthly HLH and LLH electricity prices in the AURORA Model. *See* Chapter 4 of the Study, regarding the AURORA Model. The historical monthly California hydro generation data used to incorporate risk were collected from reports published by the Energy Information Administration (EIA) for 1980-1997, which are reported in Table 6.5.

6.7.2 Sampling Hydro Generation. California hydro generation risk is modeled in RiskMod by randomly sampling, in the @RISK computer software, values from 1 to 18 (which represent each of the 18 hydro generation years) and using the associated hydro generation data in a continuous manner like that used for the 50 water year analysis. The random selection of the initial hydro generation year (for FY 2003) is accomplished by sampling real values ranging from 1 to 18 from a uniform probability distribution in a risk simulation model and subsequently converting each number to the nearest integer value (whole numbers). Given the sampled hydro generation year, the corresponding monthly California hydro generation data for that year are selected for FY 2003.

Graph 6.5 reports the number of times that each of the 18 years of hydro generation data were sampled from a uniform probability distribution for 3000 simulations. The uniform probability distribution was selected for use in the risk simulation model because it appropriately assigns

Table 6.5: California Hydro Generation for 1980 - 1997

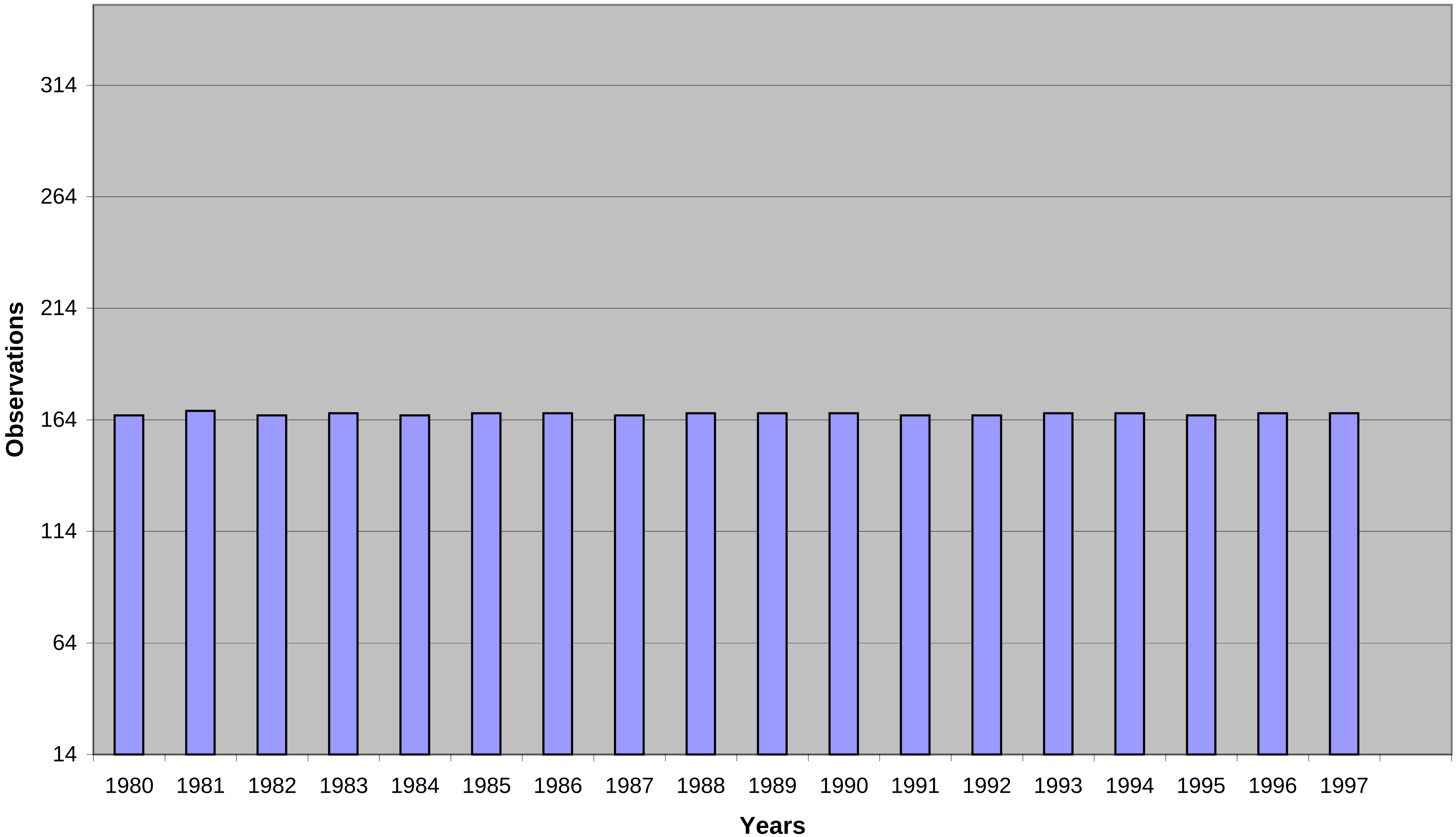
	FY	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
1	1980	2983	2486	3179	5011	5351	6007	5438	5128	4957	5087	4858	4418
2	1981	3210	3132	3142	2450	2701	2894	3471	3633	3931	4043	3667	3243
3	1982	2179	3167	5336	5649	5884	6243	6757	6800	6332	5809	5587	5146
4	1983	4036	4933	5649	5778	6903	7276	7075	7563	7547	6945	6302	5601
5	1984	4668	5338	6956	6786	5430	5250	5222	5110	5375	5517	5235	4501
6	1985	3261	3315	3950	3195	3594	3522	4176	4366	3943	4501	3962	3476
7	1986	3114	3276	3062	3215	4975	6784	5851	5423	5701	5621	4812	4721
8	1987	3750	3274	2710	2011	2342	2446	3118	3230	3322	3923	3548	3081
9	1988	2422	1951	2214	2327	2115	2392	2764	2792	3524	4238	3687	2779
10	1989	1677	1858	1887	1421	2060	3349	4318	4313	4557	5048	4415	3149
11	1990	2605	2665	2454	1995	1671	2656	3128	3164	3428	4081	3712	2692
12	1991	2522	1828	1626	1267	1146	1626	1978	2293	3711	3992	3398	2879
13	1992	2157	1664	1776	1478	1767	1991	2369	3071	2978	3106	2559	2078
14	1993	1687	1424	1704	2403	3463	5177	5785	6293	6650	5819	5071	3604
15	1994	2878	2515	2703	1767	1708	2409	2713	3226	3860	3989	3599	2403
16	1995	1875	1465	2203	3738	5443	6431	7339	7484	7507	6694	6121	4915
17	1996	3853	2910	2591	3013	5684	6597	6871	6954	6089	5442	4883	3688
18	1997	3003	2926	5204	5597	5923	5171	4896	5321	5489	5245	4796	3838

Source: Energy Information Administration (EIA) - Electric Power Monthly, Table 11. Electric Utility Hydroelectric Net Generation by Census Division and State, 1980 - 1997 equal probability to each of the 18 years of data being sampled. The average number of times that each hydro generation year could have been sampled for 3000 simulations is 166.7 (3000/18). These results in Graph 6.5 indicate that all years, except for 1981, were sampled either 166 or 167 times. The hydro generation data for 1981 were sampled 168 times.

After the initial year is selected for FY 2003 for a given simulation, hydro generation data for a sequential set of four years of data, starting with the hydro generation year selected for FY 2003, are selected from 1 through 18. When the end of the data is reached (at the end of 18), monthly hydro generation data for hydro generation year 1 is subsequently used. Thus, if a simulation starts with hydro generation data for hydro generation year 17, the simulation will use hydro generation data for years 17 and 18, as well as years 1 and 2, for a total of four sequential years of hydro generation data. This approach was used so that each of the 18 years of California hydro generation data were sampled an equal number of times. Using historical California hydro generation data in this continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 18 years of hydro generation data.

6.7.3 Use of California Hydro Generation Risk in AURORA. Variability in California hydro generation is incorporated into the AURORA Model by calculating (via the Data Manager), from monthly California hydro generation data for 18 years, California annual energy-to-capacity ratios (using the total hydro capacity value for all of California in the AURORA Model), and calculating California monthly to annual hydro generation ratios. These data are input into the AURORA Model. *See* Chapter 4 of the Study, regarding the AURORA Model. These sets of ratios are used by AURORA to calculate the annual and then the monthly hydro generation for each of the two California regions (northern and southern California) in AURORA. This process results in the sum of the hydro generation for the two California regions in AURORA being equal to the historical monthly California hydro generation.

Graph 6.5: Number of Times California Hydro Generation for 18 Years were Sampled Based on 3000 Sampled Values



6.8 California Loads Risk Factor

California load uncertainty is incorporated into the Risk Analysis to account for the impact that California load uncertainty has on monthly HLH and LLH electricity prices, which impacts BPA's surplus energy revenues and power purchase expenses. This impact is accounted for by inputting into the AURORA Model various California load values and having it estimate the associated HLH and LLH electricity prices. *See* Chapter 4 of the Study, regarding the AURORA Model.

The California Load Risk Model is designed to incorporate forecasted monthly load data from the AURORA Model such that, when no risk is being simulated, the forecasted monthly loads match the sum of the forecasted loads for the two regions (southern and northern California) that comprise California in the AURORA Model. This process results in the simulated loads reflecting variability in loads relative to the forecasted loads used in AURORA. *Id.*
California load variability is modeled in the California Load Risk Model such that annual load growth variability and monthly load swings due to weather conditions are both accounted for in one California load variability factor. This task is accomplished by first simulating annual load growth for years from 2003-2006 and then, subsequently, simulating the impact of monthly load swings due to weather on the simulated monthly loads that include load growth.

6.8.1 Annual California Load Growth Risk. Annual California load growth risk is modeled using a random-walk technique. This quantitative method simulates various annual average load levels through time with the starting point for simulating the annual average load in a given year being the annual average load level from the previous year. Under this method, simulated annual average loads randomly increase and decrease through time from the annual average load level of the prior year with the results including outcomes that represent periods of strong load growth, weak load growth, and vacillating positive and negative load growth.

Input data from the AURORA Model used in the California Load Risk Model are the following: (1) annual average 2002 California loads; (2) forecasted annual load growth for 2003–2006; and (3) monthly load shaping factors (values relative to 1.00) that were derived for use in AURORA by dividing historical monthly loads by historical annual average loads. *See* Chapter 4 of the Study, regarding the AURORA Model. Inputting the data used by the AURORA Model allows the California Load Risk Model to replicate the forecasted monthly California loads in AURORA.

Load growth variability is incorporated into the California Load Risk Model by sampling values from standard normal distributions (normal distributions with a mean of 0 and a standard deviation of 1) in @RISK, multiplying the sampled values by an annual load growth standard deviation, and adding the simulated positive and negative values to the annual load level of the prior year. The values sampled from the standard normal distribution are in terms of the number of positive or negative standard deviations and they are identical to the values sampled from the standard normal distributions used to estimate load growth risk for the PNW. By using this approach, positive/negative load growth due to the economy in California is directly linked with positive/negative load growth in the PNW due to the economy. Variability in monthly loads due to load growth variability is derived by multiplying variable annual loads by deterministic monthly load shape factors. The annual load growth standard deviation used in the California Load Risk Model is 2.4 percent, which was derived from WSCC load data from 1987-1998 for the California/Mexico Power Area. The source of this data was a publication by the WSCC titled, 10-Year Coordinated Plan Summary 1999-2008, Planning and Operation for Electric System Reliability, Western Systems Coordinating Council, October 1999, at 60. The historical WSCC load data and the annual load growth standard deviation calculations by BPA are reported in Tables 6.1 and 6.2.

6.8.2 California Load Risk Due to Weather Conditions. Monthly California load variability due to weather conditions is quantified by first sampling values from standard normal distributions in @RISK, then multiplying the sampled values by monthly load standard deviations, and finally adding the resulting positive and negative values to the simulated loads after load growth.

The monthly California load standard deviations are derived from utility-specific, monthly historical daily load standard deviations and 2005 forecasted loads for California utilities used as input data in PMDAM when performing the MCA in the 1996 rate case (*see* MCA Study Documentation, WP-96-FS-BPA-04A, Part 2 of 2; pages 305 and 256). This derivation is accomplished by calculating composite, load-weighted, monthly load standard deviations from utility specific, daily load standard deviations (for the 12 months of the year) and annual average load data.

6.8.3 Derivation of California Monthly Load Variability Due to Weather Conditions. BPA assumes, for Rate setting purposes, that daily weather patterns over the course of a month are independent and that each day of a given month has the same daily load standard deviation. Accordingly, BPA used the following statistical equation to derive monthly load standard deviations from daily load standard deviations for each month. The statistical equation for calculating the standard deviation for the average of "n" number of independent random variables is the following:

$$\sigma_{\bar{x}} = \frac{\sigma_x}{\sqrt{n}}$$

Where:

$\underline{\sigma_x}$ is the standard deviation for all independent random variables

$\bar{n}$ is the number of independent random variables

In the case of BPA's analysis, the number of independent random variables is the number of days in a month and the standard deviation for all the independent random variables is the daily load standard deviations for each month. The California monthly load standard deviations for each month are derived by inserting values for the number of days in each month and the daily load standard deviations for each month into the equation above.

Daily California load standard deviations for each month and the resulting California monthly load standard deviations are reported in Table 6.6. These monthly load standard deviations are input into the California Load Risk Model to quantify monthly load variability due to weather in RiskSim. Table 6.7 contains a copy of the California Load Risk Model**.** Results from this risk model are shown in Graph 6.6 for the 5^{th}, 50^{th}, and 95^{th} percentiles.

6.8.4 Use of Simulated California Loads in AURORA. The HLH and LLH electricity prices associated with changes in California monthly loads are estimated in the AURORA Model by inputting California load data simulated by the California Load Risk Model. *See* Chapter 4 of the Study, regarding the AURORA Model. This process involves calculating (via the Data Manager) monthly load ratios (monthly loads divided by the annual average loads) from monthly and annual load data simulated by the California Load Risk Model and then inputting the monthly ratios and annual average energy loads into the AURORA Model for each simulation. These data are input into AURORA to calculate annual and monthly loads for each of the two California regions (southern and northern California) in AURORA. This process results in the sum of the loads for the two California regions in AURORA being equal to the simulated California loads from the California Load Risk Model.

Table 6.6: Derivation of Load-Weighted, Monthly Load Standard Deviations for California

California

		Loads CY 2005	Daily Load Standard Deviations											
			Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
SCE	SCEFRM	11497	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.11	0.09	0.09	0.09
SCE	AAAFRM	423	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.11	0.09	0.09	0.09
SCE	BCRVFM	420	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.11	0.09	0.09	0.09
SCE	DWRFRM	910	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.09	0.11	0.09	0.09	0.09
LADWP	LADFRM	3366	0.09	0.09	0.10	0.10	0.10	0.11	0.12	0.11	0.12	0.11	0.10	0.09
SDG&E	SDEFRM	2319	0.07	0.08	0.07	0.07	0.08	0.09	0.09	0.09	0.10	0.08	0.07	0.07
OSC	BGPFRM	442	0.09	0.08	0.09	0.09	0.10	0.10	0.11	0.10	0.11	0.10	0.09	0.09
OSC	IIDOFM	474	0.09	0.08	0.09	0.09	0.10	0.10	0.11	0.10	0.11	0.10	0.09	0.09
PG&E	PG&FRM	10987	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	NCPFRM	393	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	REDFRM	130	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	SNCFRM	305	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	MIDFRM	275	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	TIDFRM	200	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
ONC	SMUFRM	1271	0.07	0.07	0.07	0.07	0.09	0.09	0.09	0.08	0.09	0.07	0.07	0.07
Total Cal		**33412**												

		Loads CY 2005	Daily Load Variances											
			Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
SCE	SCEFRM	11497	0.0081	0.0081	0.0081	0.0081	0.0100	0.0100	0.0100	0.0081	0.0121	0.0081	0.0081	0.0081
SCE	AAAFRM	423	0.0081	0.0081	0.0081	0.0081	0.0100	0.0100	0.0100	0.0081	0.0121	0.0081	0.0081	0.0081
SCE	BCRVFM	420	0.0081	0.0081	0.0081	0.0081	0.0100	0.0100	0.0100	0.0081	0.0121	0.0081	0.0081	0.0081
SCE	DWRFRM	910	0.0081	0.0081	0.0081	0.0081	0.0100	0.0100	0.0100	0.0081	0.0121	0.0081	0.0081	0.0081
LADWP	LADFRM	3366	0.0081	0.0081	0.0100	0.0100	0.0100	0.0121	0.0144	0.0121	0.0144	0.0121	0.0100	0.0081
SDG&E	SDEFRM	2319	0.0049	0.0064	0.0049	0.0049	0.0064	0.0081	0.0081	0.0081	0.0100	0.0064	0.0049	0.0049
OSC	BGPFRM	442	0.0081	0.0064	0.0081	0.0081	0.0100	0.0100	0.0121	0.0100	0.0121	0.0100	0.0081	0.0081
OSC	IIDOFM	474	0.0081	0.0064	0.0081	0.0081	0.0100	0.0100	0.0121	0.0100	0.0121	0.0100	0.0081	0.0081
PG&E	PG&FRM	10987	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	NCPFRM	393	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	REDFRM	130	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	SNCFRM	305	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	MIDFRM	275	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	TIDFRM	200	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
ONC	SMUFRM	1271	0.0049	0.0049	0.0049	0.0049	0.0081	0.0081	0.0081	0.0064	0.0081	0.0049	0.0049	0.0049
Total Cal		**33412**												
Number of Days Per Month			31	28	31	30	31	30	31	31	30	31	30	31
Weighted Daily Load Variances			**0.0066**	**0.0066**	**0.0068**	**0.0068**	**0.0090**	**0.0093**	**0.0096**	**0.0079**	**0.0106**	**0.0071**	**0.0068**	**0.0066**
Weighted Daily Load Standard Deviations			**0.0811**	**0.0815**	**0.0823**	**0.0823**	**0.0948**	**0.0965**	**0.0980**	**0.0887**	**0.1028**	**0.0845**	**0.0823**	**0.0811**
Monthly Load Standard Deviations			**0.0146**	**0.0154**	**0.0148**	**0.0150**	**0.0170**	**0.0176**	**0.0176**	**0.0159**	**0.0188**	**0.0152**	**0.0150**	**0.0146**

Table 6.7: California Load Risk Model for 2003 - 2006

California Load Variability

California Load Growth Uncertainty:

Forecasted Calendar Year (2002) Annual Average California Loads	31,960
Forecasted California Load Growth for 2002; Source: Aurora	0.00%
Forecasted California Load Growth for 2003; Source: Aurora	2.70%
Forecasted California Load Growth for 2004; Source: Aurora	2.68%
Forecasted California Load Growth for 2005; Source: Aurora	2.72%
Forecasted California Load Growth for 2006; Source: Aurora	2.70%
Load Growth Std Dev; Source: PMDAM	2.40%

Estimated Base Case Loads		*Std Normal Dist - Using the Same as PNW*
CY 2002	31,960	*0.0*
CY 2003	32,823	*0.0*
CY 2004	33,703	*0.0*
CY 2005	34,619	*0.0*
CY 2006	35,554	*0.0*

Load Growth Dev from any specified forecasted load level	
CY 2002	*31960*
CY 2003	*32823*
CY 2004	*33703*
CY 2005	*34619*
CY 2006	*35554*

California Load Variability Due to Load Growth Uncertainty

Calendar Year 2003

	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	Average
Average Annual California Loads (Average Energy in aMW)	32823	32823	32823	32823	32823	32823	32823	32823	32823	32823	32823	32823	
California Monthly Load Shapes (Source: AURORA)	0.953	0.933	0.919	0.925	0.955	1.063	1.125	1.167	1.075	0.971	0.943	0.961	
Simulated Monthly California Loads (Average Energy in aMW)	31292	30636	30176	30373	31357	34900	36934	38310	35292	31882	30964	31555	32,806 aMW

California Load Variability Due to Load Growth and Weather Uncertainty

	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	
California Loads (Average Energy in aMW); (From California Load Growth Worksheet)	31292	30636	30176	30373	31357	34900	36934	38310	35292	31882	30964	31555	32,806 aMW
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations in PMDAM)	1.46%	1.54%	1.48%	1.50%	1.70%	1.76%	1.76%	1.59%	1.88%	1.52%	1.50%	1.46%	
Random California Non-Fed Loads (Average Energy in aMW)	*31,292*	*30,636*	*30,176*	*30,373*	*31,357*	*34,900*	*36,934*	*38,310*	*35,292*	*31,882*	*30,964*	*31,555*	32,806 aMW

Table 6.7: California Load Risk Model for 2004 (Continued)

California Load Variability

California Load Variability Due to Load Growth Uncertainty

Calendar Year 2004

	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	Average
Average Annual California Loads (Average Energy in aMW)	33703	33703	33703	33703	33703	33703	33703	33703	33703	33703	33703	33703	
California Monthly Load Shapes (Source: AURORA)	**0.953**	**0.933**	**0.919**	**0.925**	**0.955**	**1.063**	**1.125**	**1.167**	**1.075**	**0.971**	**0.943**	**0.961**	
Simulated Monthly California Loads (Average Energy in aMW)	32130	31457	30985	31187	32197	35835	37924	39337	36238	32736	31794	32400	**33,685 aMW**

California Load Variability Due to Load Growth and Weather Uncertainty

	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	
California Loads (Average Energy in aMW); (From California Load Growth Worksheet)	32130	31457	30985	31187	32197	35835	37924	39337	36238	32736	31794	32400	**33,685 aMW**
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations	1.46%	1.54%	1.48%	1.50%	1.70%	1.76%	1.76%	1.59%	1.88%	1.52%	1.50%	1.46%	
Random California Non-Fed Loads (Average Energy in aMW)	***32,130***	***31,457***	***30,985***	***31,187***	***32,197***	***35,835***	***37,924***	***39,337***	***36,238***	***32,736***	***31,794***	***32,400***	**33,685 aMW**

Table 6.7: California Load Risk Model for 2005 (Continued)

California Load Variability

California Load Variability Due to Load Growth Uncertainty

Calendar Year 2005

	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	Average
Average Annual California Loads (Average Energy in aMW)	34619	34619	34619	34619	34619	34619	34619	34619	34619	34619	34619	34619	
California Monthly Load Shapes (Source: AURORA)	**0.953**	**0.933**	**0.919**	**0.925**	**0.955**	**1.063**	**1.125**	**1.167**	**1.075**	**0.971**	**0.943**	**0.961**	
Simulated Monthly California Loads (Average Energy in aMW)	33004	32313	31828	32035	33073	36810	38956	40407	37224	33626	32658	33282	**34,601 aMW**

California Load Variability Due to Load Growth and Weather Uncertainty

	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	
California Loads (Average Energy in aMW); (From California Load Growth Worksheet)	33004	32313	31828	32035	33073	36810	38956	40407	37224	33626	32658	33282	**34,601 aMW**
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations	1.46%	1.54%	1.48%	1.50%	1.70%	1.76%	1.76%	1.59%	1.88%	1.52%	1.50%	1.46%	
Random California Non-Fed Loads (Average Energy in aMW)	***33,004***	***32,313***	***31,828***	***32,035***	***33,073***	***36,810***	***38,956***	***40,407***	***37,224***	***33,626***	***32,658***	***33,282***	**34,601 aMW**

Table 6.7: California Load Risk Model for 2006 (Continued)

California Load Variability

California Load Variability Due to Load Growth Uncertainty

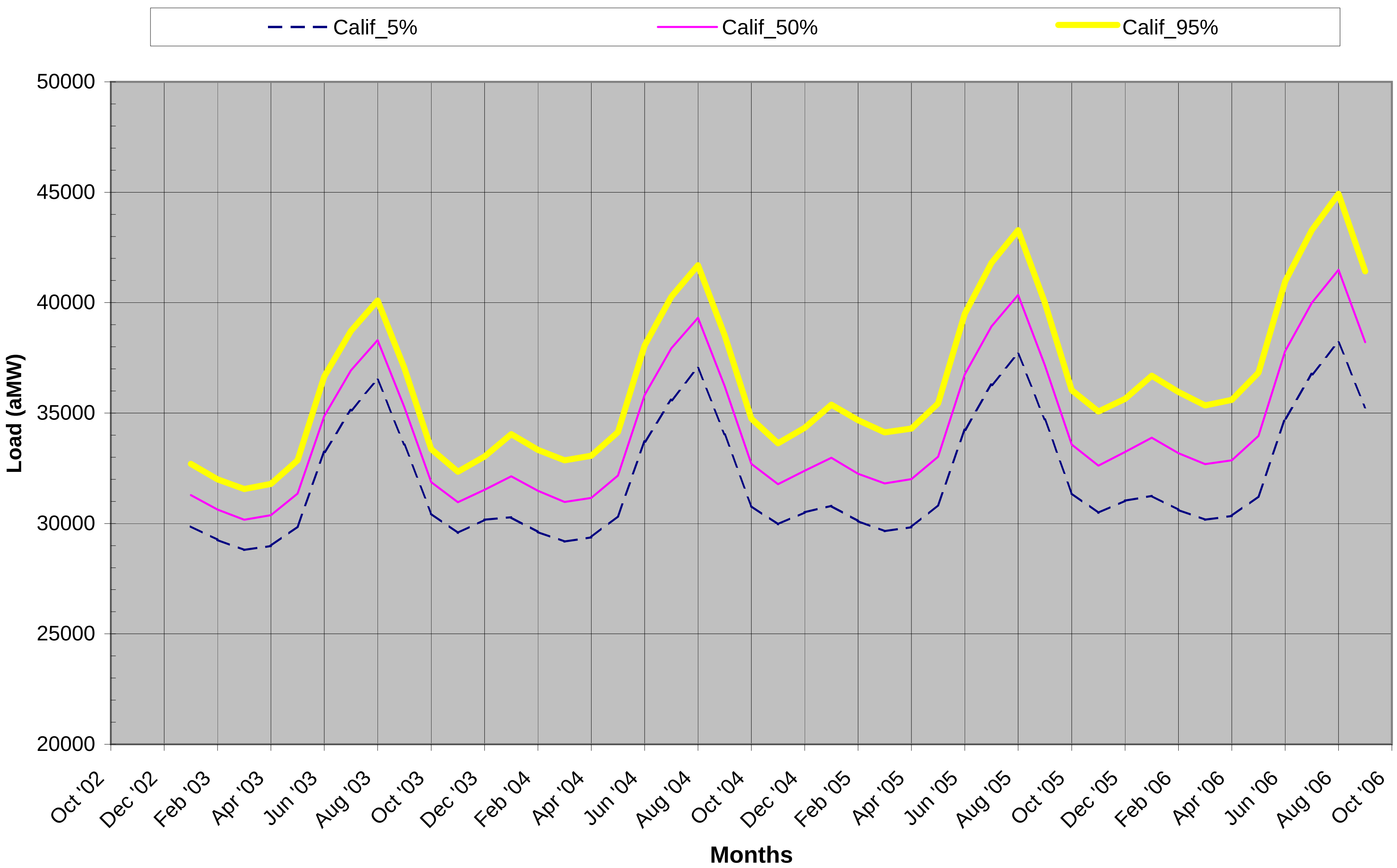
Calendar Year 2006

	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	Average
Average Annual California Loads (Average Energy in aMW)	35554	35554	35554	35554	35554	35554	35554	35554	35554	35554	35554	35554	
California Monthly Load Shapes (Source: AURORA)	**0.953**	**0.933**	**0.919**	**0.925**	**0.955**	**1.063**	**1.125**	**1.167**	**1.075**	**0.971**	**0.943**	**0.961**	
Simulated Monthly California Loads (Average Energy in aMW)	33896	33185	32687	32900	33966	37804	40007	41498	38229	34534	33540	34180	**35,536 aMW**

California Load Variability Due to Load Growth and Weather Uncertainty

	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06	Oct '06	Nov '06	Dec '06	
California Loads (Average Energy in aMW); (From California Load Growth Worksheet)	33896	33185	32687	32900	33966	37804	40007	41498	38229	34534	33540	34180	**35,536 aMW**
Monthly Load Standard Deviation (Derived, Via Simulation, from Daily Load Standard Deviations	1.46%	1.54%	1.48%	1.50%	1.70%	1.76%	1.76%	1.59%	1.88%	1.52%	1.50%	1.46%	
Random California Non-Fed Loads (Average Energy in aMW)	***33,896***	***33,185***	***32,687***	***32,900***	***33,966***	***37,804***	***40,007***	***41,498***	***38,229***	***34,534***	***33,540***	***34,180***	**35,536 aMW**

Graph 6.6: Simulated California Loads for 2002 - 2006



6.9 Natural Gas Price Risk Factor

Variability in natural gas prices is incorporated into the Risk Analysis to account for the impact that natural gas price risk has on monthly HLH and LLH electricity prices--which impacts BPA's surplus energy revenues and power purchase expenses. This impact is accounted for by inputting into the AURORA Model the simulated real monthly natural gas prices from the Natural Gas Price Risk Model and having AURORA estimate the associated nominal monthly HLH and LLH electricity prices for each simulation. *See* Chapter 4 of the Study, regarding the AURORA Model.

The Natural Gas Price Risk Model is designed to simulate various gas price patterns through time. The modeling method used to simulate gas price patterns through time is a mean-reverting, random-walk technique. The random-walk technique simulates monthly natural gas prices through time with the starting point for simulating the natural gas price in a given month being the monthly natural gas price from the prior month. Under this method, simulated monthly natural gas prices randomly increase and decrease through time from the natural gas price of the prior month. The mean-reverting technique causes simulated natural gas prices to tend to revert to the mean, or forecasted, prices, as prices move further from forecasted prices (either higher or lower).

6.9.1 Inputs into the Natural Gas Price Risk Model. The Natural Gas Price Risk Model is designed to simulate variable natural gas prices based on natural gas prices used in the AURORA Model. *See* Chapter 4 of the Study, regarding the AURORA Model. To accomplish this task, forecasted average annual delivered natural gas prices (in real $) to southern California for 2003-2006 and monthly gas price shape data (values relative to 1.00) from AURORA are input into the Natural Gas Price Risk Model. *Id.* With this data, the deterministic forecasted monthly prices in AURORA are calculated in the Natural Gas Price Risk Model by multiplying the annual average natural gas prices by the monthly gas price shapes. *Id.*

Additional information input into the Natural Gas Price Risk Model are minimum and maximum delivered gas price constraints (in real $) and monthly standard deviations for natural gas prices calculated from historical monthly spot market gas prices in terms of price movements from one month to the next month. Minimum and maximum delivered gas price constraints used in the Natural Gas Risk Model are $1.50/MMBTU (Million British Thermal Units) and $20.00/MMBTU. These price constraints are determined based on BPA's professional judgment.

Historical monthly spot market gas prices used to calculate the standard deviations for month-to-month price movements are for Ignacio, Colorado from January 1989 through December 2002. Monthly price variability is estimated in terms of month-to-month price changes so that price movements through time could be modeled using the random-walk technique. The month-to-month price changes were measured in terms of taking the natural logarithm of the ratio between each monthly price and the prior monthly price. The monthly price variability was computed by taking the standard deviation of these natural logarithm values. This approach allowed natural gas price risk to be reflected in a normal probability distribution of natural log values, and once these natural log values were sampled, they were then converted into a lognormal probability distribution of normal (non-logged) values by taking the antilog of the natural log values.

6.9.2 Modeling Natural Gas Price Variability. Statistical parameters needed to quantify risk in probability distributions in the Natural Gas Price Risk Model are developed from the Ignacio price data. This quantification allows the variability in the historical natural gas price data for Ignacio to be incorporated into the Natural Gas Price Risk Model. This process is performed in the following manner: (1) the changes in gas prices from one month to the next month for all months from January 1989 through December 2002 are calculated by dividing each monthly price by the prior monthly price and taking the natural logarithm; (2) the lognormal price changes according to month are accumulated; and (3) the standard deviation for all lognormal price changes for each month are calculated. This process results in standard deviations being calculated from 14 price deltas for all months of the year except for January (which is derived from a set of 13 price deltas). Table 6.8 contains the historical Ignacio monthly spot market natural gas prices and the calculations used to derive these statistical parameters.

The monthly standard deviations and the largest allowable monthly standard deviation values were input into truncated standard normal probability distributions in @RISK. A truncated standard normal distribution is a normal distribution having a mean of zero, a standard deviation of one, and a specified maximum and minimum value that sets an upper and lower bound on the values that can be sampled. In the @RISK computer software, this information is entered into a truncated normal probability distribution as follows:

RiskTNormal(Mean = 0, Standard deviation = 1, Min value = , Max value =).
(Where RiskTNormal = truncated normal probability distribution in @RISK)

Under this methodology, the positive and negative values sampled from the truncated standard normal distributions are the number of standard deviations of a random price movement. The number of standard deviations sampled from the monthly truncated standard normal distributions in the Natural Gas Price Risk Model are multiplied by the monthly standard deviations and the antilog of these natural logarithm price changes are multiplied times the simulated natural gas price for the prior month to derive each subsequent monthly price.

Table 6.8: Statistical Parameter Calculations for Natural Gas Price Risk Model

Ignacio Monthly Spot Gas Prices ($/MMBTU)

	1	2	3	4	5	6	7	8	9	10	11	12	Annual
Year	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Average**
1989	2.22	2.13	2.03	2.16	2.16	2.09	2.11	2.09	2.00	1.97	2.13	2.86	**2.16**
1990	3.27	2.27	1.80	1.81	1.78	1.82	1.78	1.75	1.73	2.13	2.42	2.30	**2.07**
1991	1.97	1.42	1.24	1.29	1.25	1.22	1.24	1.32	1.50	1.52	2.01	2.01	**1.50**
1992	1.47	1.33	1.41	1.60	1.69	1.76	1.85	2.11	2.50	2.45	2.41	2.47	**1.92**
1993	2.30	1.97	2.39	2.25	2.10	1.95	2.06	2.21	2.32	2.12	2.22	2.30	**2.18**
1994	2.07	2.38	2.14	1.96	1.84	1.70	1.77	1.76	1.48	1.45	1.66	1.77	**1.83**
1995	1.41	1.22	1.21	1.25	1.27	1.26	1.11	1.33	1.39	1.30	1.35	1.38	**1.29**
1996	1.30	1.31	1.26	1.24	1.21	1.40	1.86	2.01	1.66	1.96	2.82	3.72	**1.81**
1997	3.73	2.56	1.69	1.81	2.00	2.07	2.14	2.37	2.75	2.90	3.09	2.26	**2.45**
1998	2.08	2.02	2.16	2.27	2.02	1.76	1.97	1.85	1.78	1.78	2.00	1.83	**1.96**
1999	1.82	1.69	1.56	1.83	2.07	2.09	2.08	2.46	2.45	2.59	2.32	2.29	**2.10**
2000	2.26	2.43	2.61	2.77	3.07	4.36	3.74	3.45	4.16	4.55	5.16	7.72	**3.86**
2001	8.08	5.62	4.76	4.55	3.49	2.64	2.41	2.52	1.81	2.07	2.16	2.23	**3.53**
2002	2.02	2.04	2.59	2.53	2.40	2.23	2.45	2.34	2.31	2.66	3.24	3.71	**2.54**
Min	1.30	1.22	1.21	1.24	1.21	1.22	1.11	1.32	1.39	1.30	1.35	1.38	1.29
Avg	**2.57**	**2.17**	**2.06**	**2.09**	**2.03**	**2.02**	**2.04**	**2.11**	**2.14**	**2.23**	**2.47**	**2.74**	**2.10**
Max	8.08	5.62	4.76	4.55	3.49	4.36	3.74	3.45	4.16	4.55	5.16	7.72	3.86
Stdev	**1.72**	**1.09**	**0.92**	**0.85**	**0.65**	**0.77**	**0.62**	**0.54**	**0.78**	**0.87**	**0.97**	**1.67**	**0.636**

Ignacio Month-to-Month Spot Gas Price Deltas ($/MMBTU)

1989		-0.05	-0.05	0.07	0.00	-0.03	0.01	-0.01	-0.04	-0.02	0.08	0.29
1990	0.14	-0.37	-0.23	0.00	-0.02	0.02	-0.02	-0.02	-0.01	0.21	0.13	-0.05
1991	-0.16	-0.33	-0.13	0.04	-0.03	-0.02	0.02	0.06	0.12	0.01	0.28	0.00
1992	-0.31	-0.10	0.06	0.13	0.05	0.04	0.05	0.13	0.17	-0.02	-0.02	0.02
1993	-0.07	-0.15	0.19	-0.06	-0.07	-0.08	0.05	0.07	0.05	-0.09	0.05	0.03
1994	-0.10	0.14	-0.11	-0.09	-0.06	-0.08	0.04	-0.01	-0.17	-0.02	0.13	0.06
1995	-0.22	-0.14	-0.01	0.03	0.02	-0.01	-0.12	0.18	0.05	-0.07	0.04	0.02
1996	-0.07	0.01	-0.04	-0.02	-0.02	0.15	0.28	0.08	-0.19	0.16	0.36	0.28
1997	0.00	-0.38	-0.42	0.07	0.10	0.03	0.03	0.10	0.15	0.05	0.07	-0.31
1998	-0.08	-0.03	0.07	0.05	-0.11	-0.14	0.11	-0.06	-0.04	0.00	0.12	-0.09
1999	-0.01	-0.07	-0.08	0.16	0.12	0.01	-0.01	0.16	0.00	0.05	-0.11	-0.01
2000	-0.01	0.07	0.07	0.06	0.10	0.35	-0.15	-0.08	0.19	0.09	0.13	0.40
2001	0.05	-0.36	-0.17	-0.05	-0.27	-0.28	-0.09	0.04	-0.33	0.13	0.04	0.03
2002	-0.10	0.01	0.24	-0.02	-0.05	-0.07	0.09	-0.05	-0.01	0.14	0.20	0.14
Average	**-0.07**	**-0.12**	**-0.04**	**0.03**	**-0.02**	**-0.01**	**0.02**	**0.04**	**-0.01**	**0.05**	**0.11**	**0.06**

Table 6.8: (Continued)

Ignacio Month-to-Month Spot Gas Price Deltas from Average ($/MMBTU)

	Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	1989		0.08	0.00	0.04	0.01	-0.03	-0.01	-0.05	-0.04	-0.06	-0.03	0.23
	1990	0.21	-0.24	-0.19	-0.02	0.00	0.03	-0.05	-0.06	0.00	0.16	0.02	-0.11
	1991	-0.08	-0.20	-0.09	0.01	-0.01	-0.01	0.00	0.02	0.13	-0.03	0.17	-0.06
	1992	-0.24	0.02	0.10	0.10	0.07	0.05	0.03	0.09	0.17	-0.07	-0.12	-0.04
	1993	0.00	-0.03	0.24	-0.09	-0.05	-0.07	0.03	0.03	0.05	-0.14	-0.06	-0.03
	1994	-0.03	0.26	-0.06	-0.12	-0.04	-0.08	0.02	-0.05	-0.17	-0.06	0.03	0.00
	1995	-0.15	-0.02	0.03	0.01	0.03	0.00	-0.14	0.13	0.05	-0.11	-0.07	-0.04
	1996	0.01	0.14	0.00	-0.05	0.00	0.15	0.26	0.03	-0.18	0.12	0.26	0.22
	1997	0.07	-0.25	-0.37	0.04	0.12	0.04	0.01	0.06	0.16	0.01	-0.04	-0.37
	1998	-0.01	0.09	0.11	0.02	-0.10	-0.13	0.09	-0.10	-0.04	-0.05	0.01	-0.15
	1999	0.07	0.05	-0.04	0.14	0.14	0.02	-0.03	0.12	0.00	0.01	-0.22	-0.07
	2000	0.06	0.20	0.11	0.04	0.12	0.36	-0.17	-0.12	0.19	0.04	0.02	0.34
	2001	0.12	-0.24	-0.12	-0.07	-0.25	-0.27	-0.11	0.00	-0.33	0.09	-0.06	-0.03
	2002	-0.03	0.13	0.28	-0.05	-0.04	-0.07	0.07	-0.09	-0.01	0.10	0.09	0.08
Avg		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Stdev of Deltas		**0.115**	**0.172**	**0.170**	**0.071**	**0.100**	**0.142**	**0.107**	**0.083**	**0.148**	**0.090**	**0.118**	**0.178**

The mean-reversion methodology was modeled using an algorithm and a set of monthly mean reversion decay parameters (decay parameters) that adjust the value of the mean in each of the monthly truncated standard normal distributions from the typical constant of zero. The mean-reversion methodology was modeled as follows:

Simulated monthly price changes = RiskTNormal (Monthly mean-reversion decay parameters * (1 - Simulated mean-reversion ratios), 1 - Maximum monthly standard deviation, + Maximum monthly standard deviation) * monthly standard deviations

Where

RiskTNormal = Truncated normal probability distribution in @RISK with
Mean = Monthly mean-reversion decay parameters * (1- Simulated mean-reversion ratios)
Standard deviation = 1
Minimum value = - Maximum standard deviation
Maximum value = + Maximum standard deviation
And

Monthly mean-reversion decay parameters = Calibrated monthly price decay values
Simulated mean-reversion ratios = Simulated prior month price / Forecasted prior month price

6.9.3 Calibrating Natural Gas Price Variability. The final step in the modeling process is the derivation of monthly decay parameters to better calibrate the natural gas price variability simulated by the Natural Gas Price Risk Model to the historical variability reflected in the Ignacio natural gas price data. This calibration process involves running RiskMod and modifying the monthly decay parameters. The calibration of the decay values is performed in the following manner: (1) run the model; (2) calculate monthly and annual price standard deviations from the simulated data and compare the results to monthly and annual price standard deviations for the historical data; and (3) revise the decay values to test how well the monthly and annual variability of the simulated prices for a set of monthly decay values approximate the monthly and annual variability in the historical gas price data.

BPA used the statistical approach of minimizing the sum of residuals squared to help objectively determine the relative merits of one set of monthly decay values versus another. The sum of residuals squared is calculated by squaring the difference between each historical monthly natural gas price standard deviation and each simulated monthly natural gas price deviation and summing these squared differences. The lower the sum of residuals squared, the better the simulated monthly gas price variability approximates the historical monthly gas price variability. In addition to calculating the sum of residuals squared on monthly data, a set of decay values was also subjectively assessed to see how closely the annual variability of the simulated natural gas prices approximates the annual variability in the historical natural gas price data. Table 6.9 contains the results from the final calibration simulation.

The use of decay parameters, coupled with each month having different month-to-month gas price standard deviations, allows the Natural Gas Price Risk Model the flexibility to simulate that natural gas prices are more volatile in some months than others and that gas prices rise and fall at different rates during the year. Thus, the flexibility associated with the methodology utilized in the Natural Gas Price Risk Model allows the model to closely calibrate to the attributes of gas price movements in the historical data.

Table 6-10 contains a copy of the Natural Gas Price Risk Model. Results from this risk model are shown in Graph 6-7 for the 5th, 50th, and 95th percentiles.

Table 6.9: Simulated Delivered Natural Gas Prices to Southern California for 2004 (Real$/MMBTU)

Simulation #	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg	
1	5.9540	4.8917	4.3385	4.2492	4.3975	5.1930	4.7200	4.3569	4.6803	3.6886	4.2156	5.2289	4.66	
2	5.4276	3.9528	3.7665	3.7073	3.9018	3.5921	3.4475	3.0442	3.3698	3.7666	4.0752	3.9682	3.83	
3	4.8365	3.1286	3.6948	3.6741	2.9740	3.2155	2.8954	2.7470	2.5558	2.9112	3.0923	4.2800	3.33	
4	4.7548	2.6113	1.9391	2.3643	2.6465	2.6837	2.4701	2.4513	2.6788	2.7753	3.0381	3.9466	2.86	
5	5.4874	6.1046	3.0609	3.2499	4.0534	3.5369	3.5906	3.6091	4.1750	4.3752	4.3842	4.1357	4.15	
6	3.5836	4.0085	3.7056	4.0594	3.8287	3.6738	3.1950	3.2006	3.4455	3.5930	3.8428	6.3917	3.88	
7	4.8616	4.3471	4.0469	4.0105	3.8561	2.7983	2.4281	2.1451	2.3626	3.2092	3.6424	4.2603	3.50	
8	3.2214	2.8485	3.6114	3.9567	3.1849	3.4037	3.7106	3.7716	4.3095	4.7503	4.8503	4.1573	3.81	
9	4.5728	2.8870	2.2680	2.7172	2.4287	2.1438	2.1268	2.2511	1.8427	2.2872	3.0613	3.9136	2.71	
10	4.7687	3.9642	4.5544	4.5441	4.5549	4.5427	4.0004	3.5831	5.1057	5.0809	5.1198	6.6547	4.71	
						⋮								
290	4.2978	2.1418	2.2956	2.6824	2.8603	3.0500	3.1934	3.8071	3.9593	4.5182	4.6051	5.5034	3.58	
291	4.9708	5.4711	4.6273	4.5936	3.7848	3.7891	3.1360	3.6652	3.0932	3.1431	3.0432	3.0676	3.87	
292	4.7265	3.3480	3.3321	3.8085	4.3814	5.4128	4.2441	3.9666	3.8888	3.6405	3.7470	4.0699	4.05	
293	4.0655	3.8102	3.2331	3.2807	3.2461	2.9606	3.1226	2.9190	2.7481	3.4162	3.0553	3.9846	3.32	
294	6.5582	4.6776	4.3145	4.2275	4.1561	4.3790	3.5483	3.5408	3.2646	3.2283	3.5356	4.5687	4.17	
295	3.7334	1.5000	1.5000	1.7014	1.6935	1.8198	1.5446	1.6821	2.5846	2.9487	3.2782	4.0515	2.34	
296	5.7921	4.5172	3.5084	3.8170	4.0243	3.7013	3.5850	3.2809	3.0107	3.5230	3.9753	4.2593	3.92	
297	3.7751	2.3700	1.9135	2.1804	2.1713	2.3135	2.2683	2.5064	3.4450	3.6454	4.0991	4.9675	2.97	
298	5.1452	3.4883	2.0791	2.5599	2.8025	2.3064	2.2815	2.8145	2.8137	3.0978	3.5938	4.6537	3.14	
299	4.0283	2.4738	2.3922	2.5634	2.8681	3.2495	3.3625	3.3220	3.0839	3.3659	3.8456	4.0371	3.22	
300	4.5537	3.9130	3.6844	3.5452	4.1875	4.1466	4.1716	4.5133	4.2476	3.7738	3.8465	5.3160	4.16	
Avg	**5.05**	**4.03**	**3.54**	**3.64**	**3.47**	**3.58**	**3.42**	**3.50**	**3.60**	**3.87**	**4.11**	**4.60**	**3.87**	**SIM**
Max	**9.02**	**7.41**	**6.26**	**5.95**	**5.68**	**6.67**	**5.69**	**5.72**	**6.32**	**8.38**	**8.13**	**7.42**	**5.53**	**SIM**
Min	**2.35**	**1.50**	**1.50**	**1.67**	**1.59**	**1.50**	**1.50**	**1.65**	**1.68**	**1.99**	**2.13**	**2.54**	**1.95**	**SIM**

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
Mean Reversion Rate	**1.00**	**2.00**	**2.50**	**2.00**	**2.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	**1.00**	
Simulation Stdev	**1.120**	**1.114**	**0.918**	**0.818**	**0.720**	**0.817**	**0.763**	**0.768**	**0.837**	**0.843**	**0.865**	**0.980**	**0.636**
Historical Data Stdev	**1.718**	**1.088**	**0.916**	**0.847**	**0.647**	**0.774**	**0.616**	**0.540**	**0.779**	**0.871**	**0.967**	**1.674**	**0.636**
Sim Less Hist Stdev	**-0.598**	**0.026**	**0.002**	**-0.030**	**0.073**	**0.043**	**0.147**	**0.228**	**0.058**	**-0.028**	**-0.102**	**-0.694**	**0.001**
Residual ^2	**0.3577**	**0.0007**	**0.0000**	**0.0009**	**0.0053**	**0.0019**	**0.0217**	**0.0519**	**0.0034**	**0.0008**	**0.0104**	**0.4812**	**0.0000**
Sum of Squares	**935.75**												**0.001**

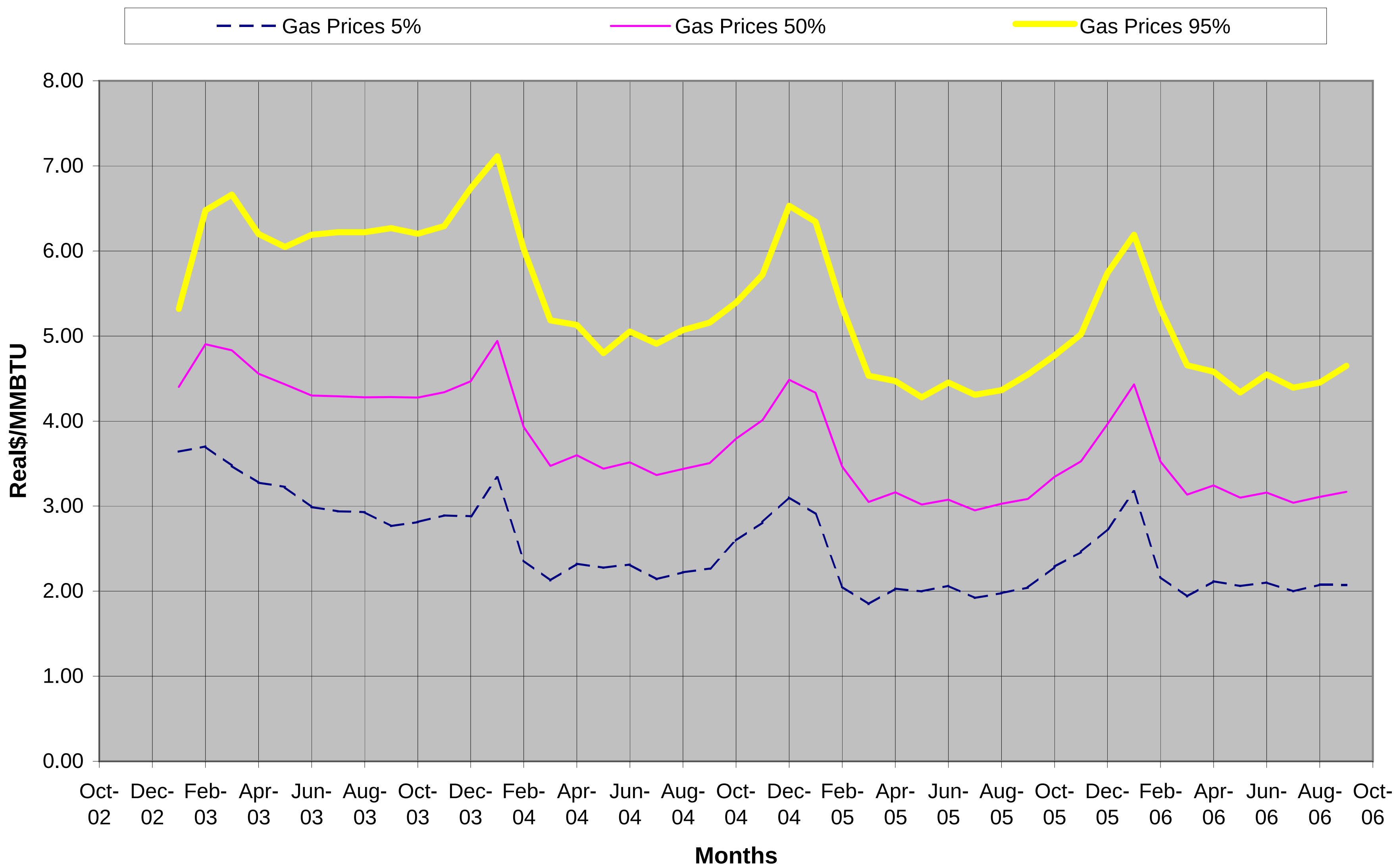
Table 6.10: Natural Gas Price Risk Model

S. California Real Delivered Prices from AURORA	Base Case	Minimum	Maximum	Sim Unconstrained	Sim Constrained
CY 2003 Avg	4.49	1.50	20.00	4.49	4.49
CY 2004 Avg	3.88	1.50	20.00	3.88	3.88
CY 2005 Avg	3.42	1.50	20.00	3.42	3.42
CY 2006 Avg	3.49	1.50	20.00	3.49	3.49
CY02-06 Avg	3.82	1.50	20.00	3.82	3.82

	Expected Price ($/MMBTU)	Standard Normal Truncated Distribution N(var mean, 1); Includes Max and Min Std Devs	Monthly Volatility	Price Risk ($/MMBTU)	Standard Normal Distribution Mean Adjustor (Causes Mean Reversion)	Monthly Log Standard Deviation	Mean Reversion Decay Parameters (Use Values >=1)	Maximum and Minimum Standard Deviations	Monthly Gas Price Shapes	Expected Price ($/MMBTU)	Minimum Price ($/MMBTU)	Maximum Price ($/MMBTU)	Unconstrained Simulated Prices ($/MMBTU)	Constrained Simulated Prices ($/MMBTU)
Initial Value					*1.00*									
Jan-03	4.40	0.00	0.12	4.40	1.00	0.115	1.00	4.00	0.98	4.40	1.50	20.00	4.40	4.40
Feb-03	4.89	0.00	0.17	4.89	1.00	0.172	2.00	4.00	1.09	4.89	1.50	20.00	4.89	4.89
Mar-03	4.85	0.00	0.17	4.85	1.00	0.170	2.50	4.00	1.08	4.85	1.50	20.00	4.85	4.85
Apr-03	4.58	0.00	0.07	4.58	1.00	0.071	2.00	4.00	1.02	4.58	1.50	20.00	4.58	4.58
May-03	4.49	0.00	0.10	4.49	1.00	0.100	2.00	4.00	1.00	4.49	1.50	20.00	4.49	4.49
Jun-03	4.36	0.00	0.14	4.36	1.00	0.142	1.00	4.00	0.97	4.36	1.50	20.00	4.36	4.36
Jul-03	4.36	0.00	0.11	4.36	1.00	0.107	1.00	4.00	0.97	4.36	1.50	20.00	4.36	4.36
Aug-03	4.36	0.00	0.08	4.36	1.00	0.083	1.00	4.00	0.97	4.36	1.50	20.00	4.36	4.36
Sep-03	4.31	0.00	0.15	4.31	1.00	0.148	1.00	4.00	0.96	4.31	1.50	20.00	4.31	4.31
Oct-03	4.31	0.00	0.09	4.31	1.00	0.090	1.00	4.00	0.96	4.31	1.50	20.00	4.31	4.31
Nov-03	4.40	0.00	0.12	4.40	1.00	0.118	1.00	4.00	0.98	4.40	1.50	20.00	4.40	4.40
Dec-03	4.53	0.00	0.18	4.53	1.00	0.178	1.00	4.00	1.01	4.53	1.50	20.00	4.53	4.53
Jan-04	5.01	0.00	0.12	5.01	1.00	0.115	1.00	4.00	1.29	5.01	1.50	20.00	5.01	5.01
Feb-04	4.00	0.00	0.17	4.00	1.00	0.172	2.00	4.00	1.03	4.00	1.50	20.00	4.00	4.00
Mar-04	3.57	0.00	0.17	3.57	1.00	0.170	2.50	4.00	0.92	3.57	1.50	20.00	3.57	3.57
Apr-04	3.69	0.00	0.07	3.69	1.00	0.071	2.00	4.00	0.95	3.69	1.50	20.00	3.69	3.69
May-04	3.53	0.00	0.10	3.53	1.00	0.100	2.00	4.00	0.91	3.53	1.50	20.00	3.53	3.53
Jun-04	3.61	0.00	0.14	3.61	1.00	0.142	1.00	4.00	0.93	3.61	1.50	20.00	3.61	3.61
Jul-04	3.45	0.00	0.11	3.45	1.00	0.107	1.00	4.00	0.89	3.45	1.50	20.00	3.45	3.45
Aug-04	3.53	0.00	0.08	3.53	1.00	0.083	1.00	4.00	0.91	3.53	1.50	20.00	3.53	3.53
Sep-04	3.61	0.00	0.15	3.61	1.00	0.148	1.00	4.00	0.93	3.61	1.50	20.00	3.61	3.61
Oct-04	3.88	0.00	0.09	3.88	1.00	0.090	1.00	4.00	1.00	3.88	1.50	20.00	3.88	3.88
Nov-04	4.11	0.00	0.12	4.11	1.00	0.118	1.00	4.00	1.06	4.11	1.50	20.00	4.11	4.11
Dec-04	4.58	0.00	0.18	4.58	1.00	0.178	1.00	4.00	1.18	4.58	1.50	20.00	4.58	4.58
Jan-05	4.41	0.00	0.12	4.41	1.00	0.115	1.00	4.00	1.29	4.41	1.50	20.00	4.41	4.41
Feb-05	3.52	0.00	0.17	3.52	1.00	0.172	2.00	4.00	1.03	3.52	1.50	20.00	3.52	3.52
Mar-05	3.15	0.00	0.17	3.15	1.00	0.170	2.50	4.00	0.92	3.15	1.50	20.00	3.15	3.15
Apr-05	3.25	0.00	0.07	3.25	1.00	0.071	2.00	4.00	0.95	3.25	1.50	20.00	3.25	3.25
May-05	3.11	0.00	0.10	3.11	1.00	0.100	2.00	4.00	0.91	3.11	1.50	20.00	3.11	3.11
Jun-05	3.18	0.00	0.14	3.18	1.00	0.142	1.00	4.00	0.93	3.18	1.50	20.00	3.18	3.18
Jul-05	3.04	0.00	0.11	3.04	1.00	0.107	1.00	4.00	0.89	3.04	1.50	20.00	3.04	3.04
Aug-05	3.11	0.00	0.08	3.11	1.00	0.083	1.00	4.00	0.91	3.11	1.50	20.00	3.11	3.11
Sep-05	3.18	0.00	0.15	3.18	1.00	0.148	1.00	4.00	0.93	3.18	1.50	20.00	3.18	3.18
Oct-05	3.42	0.00	0.09	3.42	1.00	0.090	1.00	4.00	1.00	3.42	1.50	20.00	3.42	3.42
Nov-05	3.63	0.00	0.12	3.63	1.00	0.118	1.00	4.00	1.06	3.63	1.50	20.00	3.63	3.63
Dec-05	4.04	0.00	0.18	4.04	1.00	0.178	1.00	4.00	1.18	4.04	1.50	20.00	4.04	4.04

	Expected Price ($/MMBTU)	Standard Normal Truncated Distribution N(var mean, 1); Includes Max and Min Std Devs	Monthly Volatility	Price Risk ($/MMBTU)	Standard Normal Distribution Mean Adjustor (Causes Mean Reversion)	Monthly Log Standard Deviation	Mean Reversion Decay Parameters (Use Values >=1)	Maximum and Minimum Standard Deviations	Monthly Gas Price Shapes	Expected Price ($/MMBTU)	Minimum Price ($/MMBTU)	Maximum Price ($/MMBTU)	Unconstrained Simulated Prices ($/MMBTU)	Constrained Simulated Prices ($/MMBTU)
Jan-06	4.50	0.00	0.12	4.50	1.00	0.115	1.00	4.00	1.29	4.50	1.50	20.00	4.50	4.50
Feb-06	3.59	0.00	0.17	3.59	1.00	0.172	2.00	4.00	1.03	3.59	1.50	20.00	3.59	3.59
Mar-06	3.21	0.00	0.17	3.21	1.00	0.170	2.50	4.00	0.92	3.21	1.50	20.00	3.21	3.21
Apr-06	3.32	0.00	0.07	3.32	1.00	0.071	2.00	4.00	0.95	3.32	1.50	20.00	3.32	3.32
May-06	3.18	0.00	0.10	3.18	1.00	0.100	2.00	4.00	0.91	3.18	1.50	20.00	3.18	3.18
Jun-06	3.25	0.00	0.14	3.25	1.00	0.142	1.00	4.00	0.93	3.25	1.50	20.00	3.25	3.25
Jul-06	3.11	0.00	0.11	3.11	1.00	0.107	1.00	4.00	0.89	3.11	1.50	20.00	3.11	3.11
Aug-06	3.18	0.00	0.08	3.18	1.00	0.083	1.00	4.00	0.91	3.18	1.50	20.00	3.18	3.18
Sep-06	3.25	0.00	0.15	3.25	1.00	0.148	1.00	4.00	0.93	3.25	1.50	20.00	3.25	3.25
Oct-06	3.49	0.00	0.09	3.49	1.00	0.090	1.00	4.00	1.00	3.49	1.50	20.00	3.49	3.49
Nov-06	3.70	0.00	0.12	3.70	1.00	0.118	1.00	4.00	1.06	3.70	1.50	20.00	3.70	3.70
Dec-06	4.12	0.00	0.18	4.12	1.00	0.178	1.00	4.00	1.18	4.12	1.50	20.00	4.12	4.12

Graph 6.7: Simulated Real Delivered Natural Gas Prices for Southern California (2003 - 2006)



6.9.4 Use of Simulated Natural Gas Prices in AURORA. The price impacts associated with changes in natural gas prices are estimated in the AURORA model by inputting real monthly gas price data simulated by the Natural Gas Price Risk Model. *See* Chapter 4 of the Study, regarding the AURORA Model. From each simulation of monthly southern California natural gas prices (in real $), annual gas prices and monthly gas price ratios (monthly gas prices divided by annual gas prices) are derived. From this data, simulated monthly and annual gas prices are derived for each of the 13 regions that represent the Western Systems Coordinating Council (WSCC) region in AURORA. This task is accomplished by adding deterministic positive/negative annual average price basis differences for each of the remaining 12 regions in AURORA to the simulated annual average delivered natural gas prices for southern California to get annual average natural gas prices for all 13 regions. Monthly natural gas prices for each of the remaining 12 regions are derived by using the simulated monthly gas price ratios for Southern California to yield monthly natural gas prices for all 13 regions. *See* Chapter 4 of the Study, regarding the AURORA Model.

6.10 CGS Nuclear Plant Performance Risk Factor

CGS Nuclear Plant generation risk is incorporated into the Risk Analysis to account for the impact that changes in CGS performance have on the amount of BPA's surplus energy revenues and power purchase expenses. CGS Nuclear Plant generation risk is modeled using the following equation:

CGS Output = (CGS capacity * H * RiskUniform(0,1))/(1+(H - 1)*RiskUniform(0,1)), where

CGS capacity = the maximum amount of output that can be produced by CGS;
H = calibration factor;

RiskUniform(0,1) = a uniform probability distribution in @RISK that samples real values between 0 and 1.

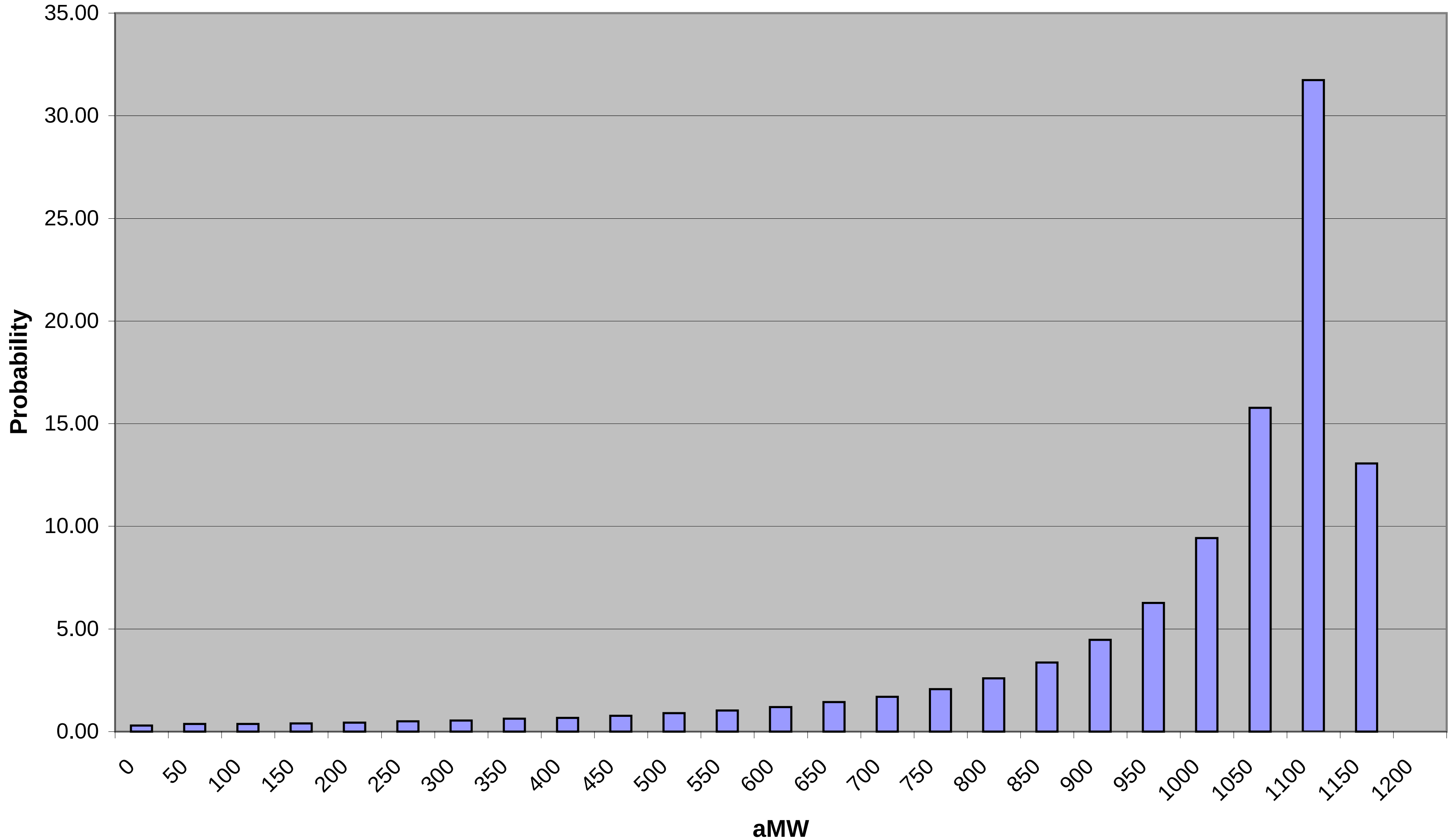
Inputs into the CGS Nuclear Plant Risk Model consist of the forecasted peak capability of CGS (1,162 MW) and expected monthly energy output reported in the Loads and Resources Study (*see* Chapter 2 of the Study). The calibration factor (H) is derived by running risk simulations and modifying the factor until the expected monthly CGS output values from the risk simulations are equal to the expected monthly values reported in the Loads and Resources Study. *Id.*

Using this equation, monthly CGS output varies from zero to peak output capability as values sampled from uniform probability distributions vary from zero to one. Although the values ranging from zero to one sampled from the uniform probability distributions are symmetrical, the frequency distribution of CGS output produced from the equation is negatively skewed with the median value (the value at the 50^{th} percentile) being higher than the average. The shape of the frequency distribution reflects that thermal plants (including CGS) typically operate at output levels higher than average output levels, but the average output is driven down by occasional forced outages in which monthly output can be substantially lower than the typical monthly output. The simulated frequency distribution for CGS output for October 2003 is shown in Graph 6.8.

6.11 Data Management Procedures

Various computer applications facilitate the movement of data between the Risk Input Data Base and RiskSim, AURORA, and RevSim. These computer applications are collectively referred to as Data Management Procedures. Of the Data Management Procedures, the principal computer program is referred to as the "Data Manager." However, other computer code (embedded in other modules of RiskMod) are components of the Data Management Procedures. This

Graph 6.8: Simulated CGS Output Distribution for October 2003

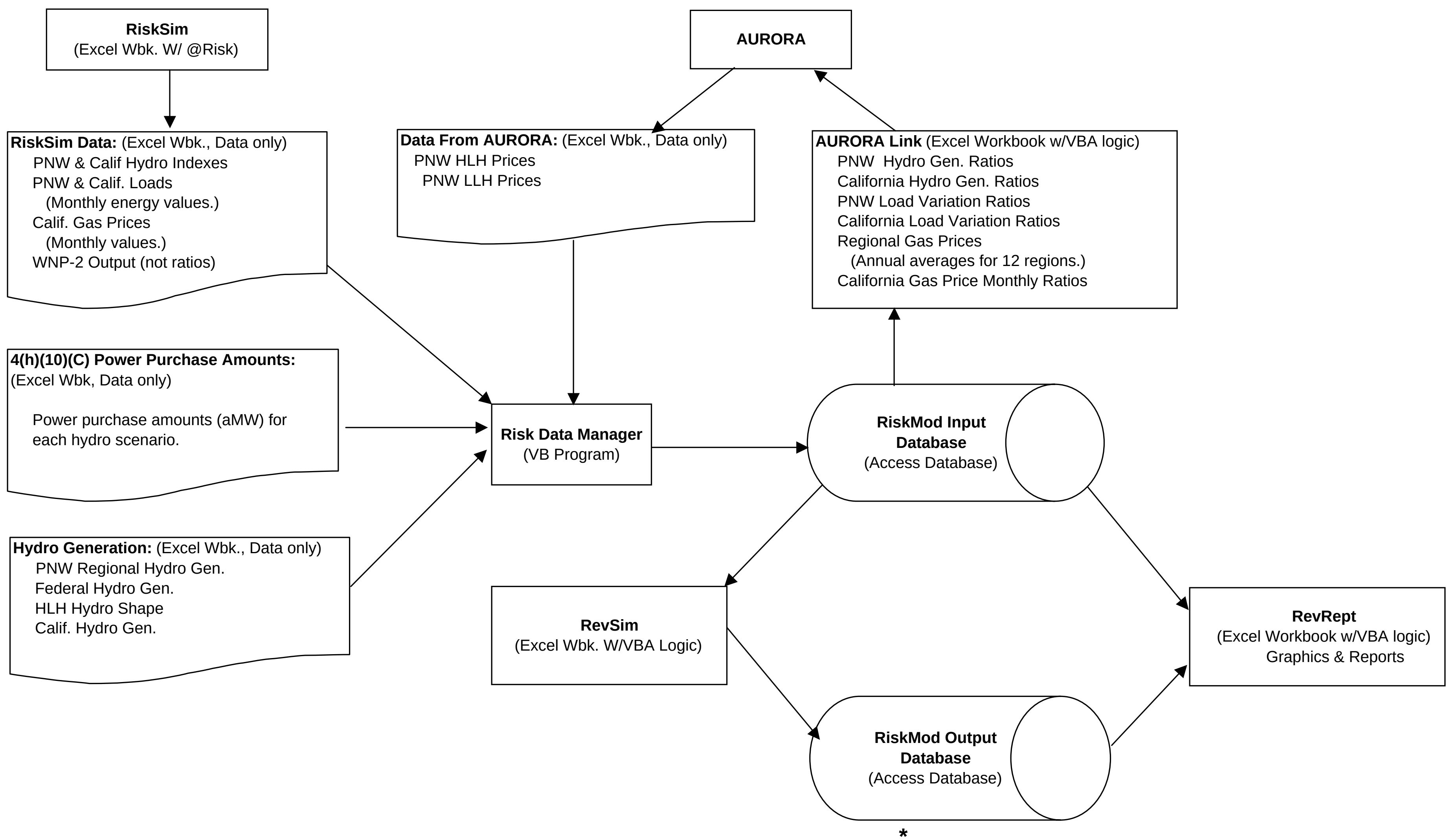


documentation of the Data Management Procedures discusses the process of inputting forecasted deterministic data and risk data simulated by RiskSim into the Risk Input Data Base, inputting data stored in the Risk Input Data Base into the AURORA Model, and downloading the results from AURORA into the Risk Input Data Base. *See* Chapter 4 of the Study, regarding the AURORA Model.

Each of these tasks is accomplished as follows. The Data Manager inputs both deterministic forecasted data and risk data simulated by RiskSim into the Risk Input Data Base. The Data Manager provides a table of PNW hydro generation values (as ratios) for each of the 50 water years that is input into the AURORA Model to estimate HLH and LLH electricity prices. Once AURORA has completed estimating HLH and LLH electricity prices for a specified number of simulations, the Data Manager downloads the prices from AURORA into the Risk Input Database.

An Excel workbook called "AURORA Link" is used to provide data from the Risk Input Data Base into AURORA so that it can estimate HLH and LLH electricity prices. Procedures in the AURORA Link workbook provide variable PNW and California hydro generation, PNW and California loads, and natural gas price data for input into AURORA (s*ee* Chapter 4 of the Study, regarding the AURORA Model) so that AURORA is able to estimate HLH and LLH electricity prices for a specified number of simulations. For each simulation, computer code housed within RevSim inputs risk data that impact net revenues. The risk data include the following: Federal hydro generation (50 water years), Federal HLH hydro generation ratio (50 water years), PNW/BPA load variability, CGS output variability, AURORA prices, and 4(h)(10)(C) purchase amounts from the Risk Input Data Base. The computer code runs RiskMod and writes the net revenue results to the Risk Output Data Base. These procedures are represented in Figure 6-1.

Figure 6.1: RiskMod Data Management Procedure



The computer code contained in these procedures is comprised of a combination of Microsoft Visual Basic and Structured Query Language. The Visual Basic code may appear as Visual Basic (VB) Script, Visual Basic for Applications (VBA), or VB 5.0.

The Risk Data Base is composed of one Risk Input Database and one Risk Output Database. Figure 6-2 depicts a typical Risk Input Data Base and Figure 6-3 depicts a typical Risk Output Data Base.

In addition to incorporating variability in Federal HLH and LLH and PNW hydro generation, the Risk Analysis incorporates variability in PNW/BPA and California loads and resources, and natural gas prices.

6.12 Loading Data

6.12.1 Forecasted Data. The data for PNW and Federal hydro generation, Federal HLH hydro generation factors, California hydro generation, and 4(h)(10)(C) purchase amounts (aMW) are considered forecasted data. Forecasted data are loaded into the Risk Input Data Base using the Data Manager. Some non-varying data, such as data from the Revenue Forecast and the Loads and Resources Study, are input directly from Excel worksheets into RevSim. Data that are entered into RevSim in this manner are not considered in this discussion.

6.12.2 Hydro Generation Data. The Data Manager is used to input monthly hydro generation data for each of the 50 water years into the Risk Input Data Base and calculate annual average hydro generation data for each calendar year.

6.12.3 4(h)(10)(C) Purchase Amounts. Power purchase amounts (monthly aMW) for the 4(h)(10)(C) calculation are input to the Risk Input Data Base using the Data Manager.

Figure 6.2: Typical Risk Input Database shown in Microsoft Access

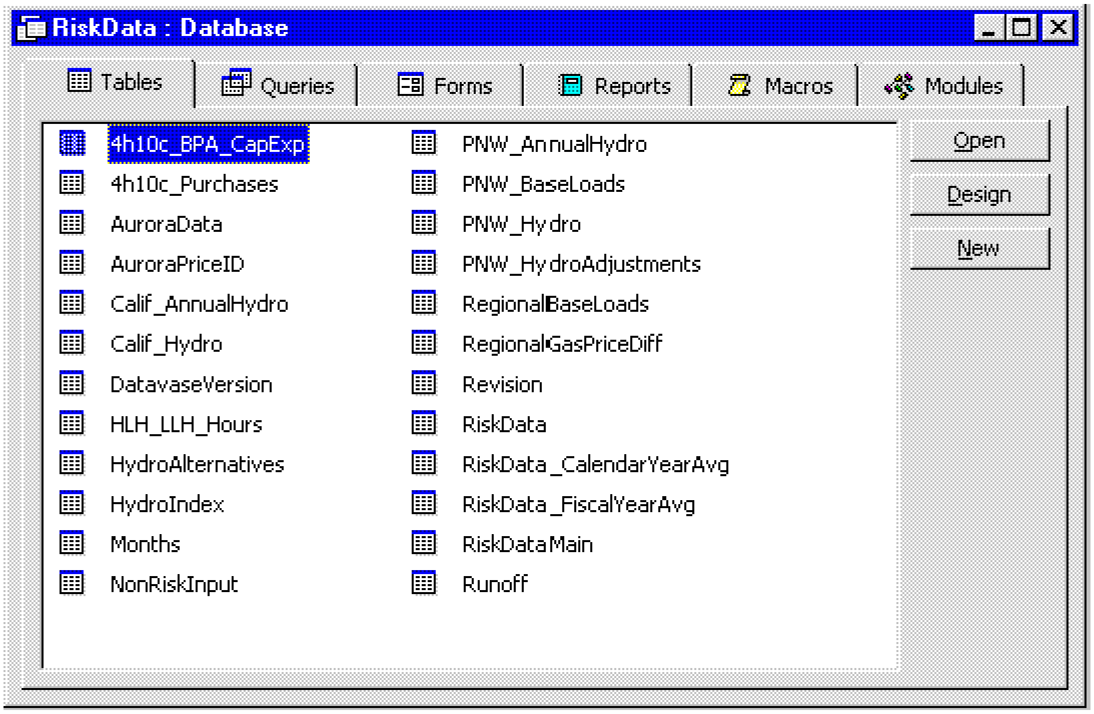
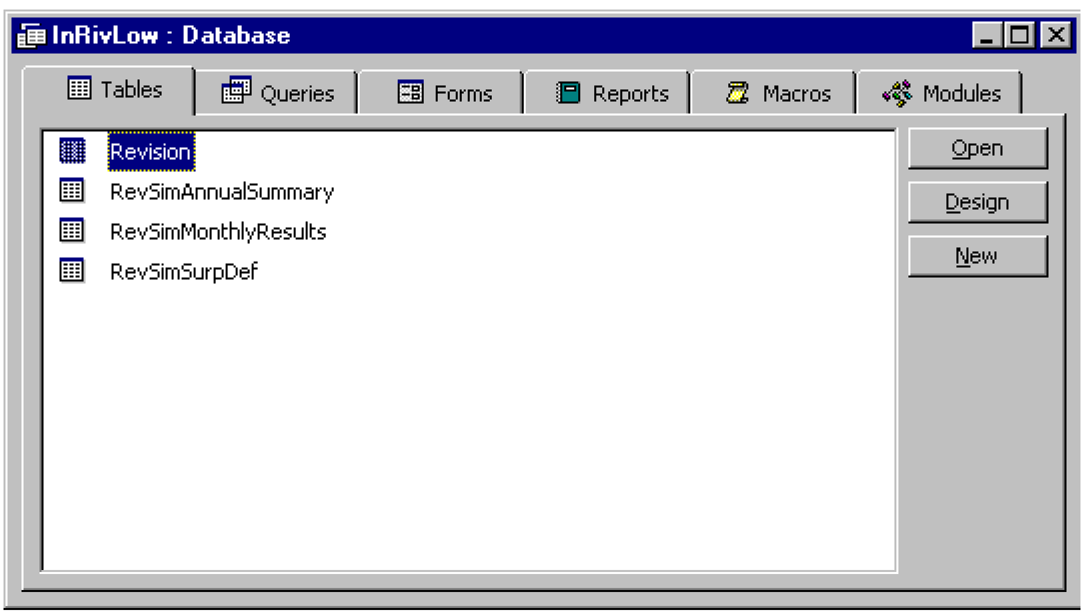


Figure 6.3: Typical Risk Output Database shown in Microsoft Access



6.13 Inputting the RiskSim Results

RiskSim is used to generate variable CGS generation, PNW/BPA and California loads, and natural gas prices. These values are combined with a random selection of PNW, Federal, and California hydro generation data. Hydro generation data used for a given simulation are defined by a “hydro index” for FY 2004-2006 and by a “refill hydro index” for FY 2003. The PNW and Federal hydro indices are represented by water years 1929-1978. The California hydro index is represented by a number from 1 to 18. This procedure is used to develop 3000 sets of 4-year outcomes of data, which are input into AURORA to estimate HLH and LLH electricity prices and input into RevSim to estimate BPA's net revenue risk.

The Data Manager loads the monthly data from the 3000 simulations into the Risk Input Data Base. Calendar year and fiscal year averages are computed for CGS, PNW loads, California loads, and natural gas prices as part of this procedure.

6.14 Interaction With the AURORA Model

AURORA uses an Access database to supply input data for each variable to its logic. The database consists of numerous tables, each containing input data. After AURORA has input data from the database and been run, the results are output to an output Access database. This process is performed using scripting, which is a VB language built into AURORA that allows the user to run AURORA commands, run the commands of other applications (*i.e.*, Excel), and to build loops to repeat procedures.

PNW hydro generation data are supplied to AURORA as monthly energy “ratios” and a 13th value, which is the annual average hydro generation capacity factor. The monthly hydro generation ratios supplied to AURORA are computed by the Data Manager and written to an

Excel workbook. These monthly hydro generation ratios are computed by dividing the monthly hydro generation by the annual average hydro generation (calendar year average) for each of the 50 water years. The annual energy-to-capacity factor is calculated by dividing the PNW annual average hydro generation for each of the 50 water years (s*ee* Chapter 2 of the Study, regarding PNW hydro generation) by the PNW hydro capacity used in AURORA (*see* Chapter 4 of the Study, regarding AURORA).

The first step in preparing AURORA is to establish a link between the Access input file used by AURORA and the Excel workbook (produced by the Data Manager) that contains the monthly hydro generation ratios. This link allows AURORA to read the data that is in an Excel workbook. Second, a macro is used to alter values in the Excel workbook. Finally, a script file runs AURORA, writes the output from AURORA to an Excel workbook, revises the input data used by AURORA for the next simulation, and then runs AURORA again. The script file contains a loop that repeats this procedure 3000 times. Upon completion of this process, AURORA produces an Excel workbook containing monthly HLH and LLH electricity prices for each iteration for 4 years, which the Data Manager loads into the Risk Input Data Base.

Variation in PNW and California loads and natural gas prices are also considered along with variability in PNW and California hydro generation. An Excel workbook is used to store data for a single simulation that is refreshed with data from the Risk Input Database for each simulation. This workbook is called "AURORA Link." The AURORA Link workbook contains both VBA procedures and data for hydro generation, loads, and natural gas prices. The VBA procedures are designed so that they can be called by the VBA scripting within AURORA.

Scripting is used to call the VBA procedures in AURORA Link, run AURORA, and write HLH and LLH electricity prices to an Excel Workbook. The script file contains a loop that runs this procedure for 3000 simulations. Upon completion of the 3000 simulations, an Excel workbook receives HLH and LLH electricity prices estimated by AURORA. These HLH and LLH electricity prices are loaded into the Risk Input Data Base by the Data Manager.

6.15 Interaction with RevSim

RevSim contains VBA procedures to extract data from the Risk Input Data Base and write results to the Risk Output Data Base.

RevSim uses the following data from the Risk Input Data Base:

(1) Federal hydro generation;

(2) HLH ratios for shaping hydro generation;

(3) BPA load variability (derived from PNW load variability);

(4) CGS output;

(5) AURORA HLH and LLH prices; and

(6) 4(h)(10)(C) purchase amounts (aMW).

Surplus energy sales and purchase amounts (aMW), surplus energy revenues and power purchase expenses, and several other items to be discussed below are calculated by RiskMod and written to the Risk Output Data Base.

6.15.1 Federal HLH and LLH Hydro Generation. For a given simulation, Federal hydro generation data and HLH hydro generation ratios from the HOSS Model for FY 2004-2006 are determined by the water year sampled for the "hydro index." The hydro index is the water year to use for the first fiscal year, *i.e.,* FY 2004. Successive water years are used for each subsequent fiscal year. For example, if water year 1940 is selected as the hydro index for a given simulation, then hydro generation data for water year 1940 are used for FY 2004, hydro generation data for water year 1941 are used for FY 2005, etc. If water year 1978 is selected as the hydro index, then the data is "wrapped" to water year 1929, *i.e.*, hydro generation data for water year 1978 are used for FY 2004, hydro generation for water year 1929 are used for FY 2005, etc. Given the hydro index (water year) for a simulation, the Federal hydro generation data and HLH hydro generation ratios are retrieved from the Risk Input Data Base.

For a given simulation, Federal hydro generation data and HLH hydro generation ratios from the HOSS Model for FY 2003 are determined by the water year sampled for the "refill hydro index." The refill hydro index is the water year to use for FY 2003. Given the refill hydro index (water year) for a simulation the Federal hydro generation data and HLH hydro generation ratios are retrieved from the Risk Input Data Base.

6.15.2 BPA Load Variability Ratios. BPA load variability ratios are calculated by dividing simulated PNW loads by the forecasted PNW loads for the corresponding month and year. These ratios are input into RevSim to modify PF loads.

6.15.3 CGS Output. Variability in CGS output is input from the Risk Input Database into RevSim. These values modify the amount of resources that BPA has available for each simulation.

6.15.4 AURORA HLH and LLH Prices. The HLH and LLH electricity prices for each simulation are read from the Risk Input Database and input into RevSim.

6.15.5 4(h)(10)(C) Purchase Amounts. The Risk Input Data Base contains the monthly amounts of 4(h)(10)(C) power purchases (aMW) for each of the 50 water years. The power purchase amounts (aMW) are read from the Risk Input Database and input into RevSim to calculate the 4(h)(10)(C) credits ($).

6.15.6 Risk Output Data Base. RiskMod produces a separate Risk Output Data Base. The Risk Output Data Base contains annual summary values data for net revenues, total revenues, 4(h)(10)(C) credits, and FCCF credits.

The Risk Output Data Base also contains monthly HLH and LLH surplus energy data (sales (aMW), prices, and revenues) and monthly HLH and LLH power purchase data (power purchases (aMW), prices, and expenses).

6.16 Operational Net Revenue Risk Analysis Model (RevSim)

RevSim is the computer model in which firm and surplus energy revenues and balancing power purchase expenses, 4(h)(10)(C) credits, and FCCF credits are calculated under various load, resource, and market price conditions to estimate BPA's operational net revenue risk. Inputs into RevSim consist of deterministic monthly load and resource data, some firm load revenues, monthly PF, IP, and RL rates, LB CRAC and FB CRAC rates, Slice Revenue Requirements, and annual expenses (other than purchase power expenses) from the Loads and Resources Study, the Revenue Recovery, and the Revenue Forecast. *See* Chapters 2, 3, and 5 of the Study.

Because RiskMod uses an aggregate load forecast, rather than individual contract details (*i.e.*, stepped rates, credits, etc) reflected in the Revenue Forecast, a calibration adjustment is made to align the deterministic revenues calculated in RiskMod with the revenues in the Revenue Forecast. Similarly, RiskMod estimates deterministic Slice revenues and revenues associated with the LB and FB CRAC which are calibrated to the revenues in the Revenue Forecast.

To quantify net revenue risk, data are input into RevSim from the Risk Input Data Base, which varies the levels of the Priority Firm (PF) loads, the output of CGS, the amount of HLH and LLH Federal hydro generation, and the HLH and LLH electricity prices from the AURORA Model.

See Chapter 4 of the Study, regarding the AURORA Model. Using this data, net revenues are calculated for each simulation.

6.17 Details of RevSim Modeling

6.17.1 Loads and Resources. A key attribute of RevSim is that it is a HLH and LLH loads and resources model. For each simulation, it estimates BPA's HLH and LLH load and resource condition. All the HLH and LLH load and resource data used in RevSim are obtained from the Loads and Resources Study. *See* Chapter 2 of the Study. The shaping of hydro generation into HLHs is measured as a ratio relative to average energy. These HLH ratios are obtained from a computer run of HOSS. *See* Hydro Regulation component of the Loads and Resources Study (Chapter 2 of the Study), regarding HOSS. The HLH shaping ratios from HOSS are multiplied by average monthly hydro generation data for each of the 50 water years from the Hydro regulation component of the Loads and Resources Study.   *See* Hydro Regulation component of the Loads and Resources Study (Chapter 2 of the Study). Given the ratios for the HLH shaping of hydro generation, the ratios for the LLH shaping of hydro generation are computed in RevSim.

All the risk data, with the exception of PF load variability, are input into RevSim as values.
PF load variability is quantified as ratios relative to 1.00. These load variability ratios are multiplied by the forecasted monthly PF loads subject to the load variance charge. The differences between the simulated and forecasted values are added to the forecasted monthly PF loads in the Revenue Forecast to obtain variable PF loads. This calculation is reflected in the following equation: Simulated PF load = Forecasted PF load + (PF (LV) load * Ratio) - PF (LV) load), where PF (LV) load is the amount of PF load subject to the load variance charge.

These variable PF loads are used to compute variable full and partial requirements customer energy revenues. In addition to adjusting PF loads (energy), the ratios (relative to 1.00) are multiplied by the forecasted monthly PF demand in the Revenue Forecast to obtain variable PF demand. These variable demand values are used to compute variable full and partial requirements customers demand revenues.

The impact to the Slice product on surplus energy sales and balancing power purchases is calculated in RevSim. The load impact is included in the load data received from the Loads and Resources Study. *See* Chapter 2 of the Study. The resource impact is quantified by modeling the Slice share of Federal hydro generation and the output from the Columbia Generating Station (CGS), decremented for certain system obligations which are not subject to Slice. The Slice share used in this proposal is 22.7 percent. The 22.7 percent of the resources was derived by dividing 1,604 aMW of Slice by the Slice Total System Inventory of 7,070 aMW.

Transmission losses are incorporated into RevSim by reducing Federal hydro generation and CGS output by 2.82 percent. The 2.82 percent loss factor represents the transmission losses on BPA's transmission system, excluding losses on the Southern Intertie. This loss factor is identical to the loss factor used in the Loads and Resources Study. *See* Hydro Regulation component of the Loads and Resources Study (Chapter 2 of the Study).

In addition to the resources in the Loads and Resources Study, RevSim includes logic that reflects Non-Treaty Storage operations. BPA's ability to store and remove energy from Non-Treaty Storage is modeled via an algorithm. The parameters in the Non-Treaty Storage algorithm are the total amount of energy that can be stored, the beginning Non-Treaty Storage level, and monthly maximum and minimum storage and release constraints.

The algorithm tracks the level of Non-Treaty Storage from month to month and stores and releases energy within operational constraints. Non-Treaty Storage is modeled to have first call on all surplus energy and is withdrawn before any power purchases are made. The storage and withdrawal decisions for Non-Treaty Storage are based on average monthly energy surplus and deficit values.

Non-Treaty Storage operations were not model in RevSim for FY 2003 because they were reflected in the FY 2003 Federal hydro generation data. *See* Hydro Regulation component of the Loads and Resources Study (Chapter 2 of the Study).

Non-Treaty Storage operations for FY 2004-2006 were modeled in RevSim. The starting FY 2004 Non-Treaty Storage balance in RevSim was set to 638 MW-Mo to reflect the forecasted expected Non-Treaty Storage level at the end of FY 2003 and a maximum Non-Treaty Storage level limit of 2,800 MW-Mo was used for FY 2004-2006, which is less than total Non-Treaty Storage of 4,763 MW-Mo. With the cap of 2,800 MW-Mo, expected Non-Treaty storage levels at the beginning of each Fiscal Year were about 2,000 MW-Mo. A copy of the Non-Treaty Storage algorithm and an example of how it works during FY 2003-2006 is provided in Table 6.11.

Table 6.11: Example of Non-Treaty Storage Operations for FY 2003 - FY 2006

Non-Treaty Storage Operation (FY 2003)

<u>The Hydroregulation Study for FY 2003 Included NTS Operation</u>

Total Non-Treaty Storage Available to BPA (MW-Mo)	2800
Non-Treaty Storage H/K (Currently Not Being Used)	145
Initial, Beginning of the Month, Non-Treaty Storage Level (MW-Mo)	**638**
Month of Beginning Non-Treaty Storage Level (MW-Mo); (Oct = 1)	**1**

	Oct '02	Nov '02	Dec '02	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	Jul '03	Aug '03	Sep '03
Monthly Maximum Storage Constraints (MW-Mo)	675	675	1350	1350	1350	675	270	675	675	0	0	675
Monthly Maximum Release Constraints (MW-Mo)	675	675	270	675	675	675	0	0	0	675	675	675
Month Number	1	2	3	4	5	6	7	8	9	10	11	12
Beginning Monthly Non-Treaty Storage Balance (MW-Mo)	**638**	**638**	**638**	**638**	**638**	**638**	**638**	**638**	**638**	**638**	**638**	**638**
Amount of Remaining Storage (MW-Mo)	2162	2162	2162	2162	2162	2162	2162	2162	2162	2162	2162	2162
BPA Monthly Surpluses/Deficits												

Storage Transactions:

	Oct '02	Nov '02	Dec '02	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	Jul '03	Aug '03	Sep '03
BPA Deficit Amount												
Energy Released From NTS	0	0	0	0	0	0	0	0	0	0	0	0
BPA Surplus Amount												
Energy Stored in NTS	0	0	0	0	0	0	0	0	0	0	0	0
Ending Monthly Non-Treaty Storage Balance (MW-Mo)	638	638	638	638	638	638	638	638	638	638	638	638

Results

	Oct '02	Nov '02	Dec '02	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	Jul '03	Aug '03	Sep '03
Non-Treaty Storage Transactions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Table 6.11: Example of Non-Treaty Storage Operations for FY 2004 (Continued)

Non-Treaty Storage Operation (FY 2004)

NOTE: Logic for July and August forces release of Non-Treaty Storage to comport with fish operations for these months

	Oct '03	Nov '03	Dec '03	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	Jul '04	Aug '04	Sep '04
Monthly Maximum Storage Constraints (MW-Mo)	675	675	1350	1350	1350	675	270	675	675	0	0	675
Monthly Maximum Release Constraints (MW-Mo)	675	675	270	675	675	675	0	0	0	675	675	675
Month Number	1	2	3	4	5	6	7	8	9	10	11	12
Beginning Monthly Non-Treaty Storage Balance (MW-Mo)	**638**	1313	1664	2299	2800	2800	2800	2800	2800	2800	2125	1450
Amount of Remaining Storage (MW-Mo)	2162	1487	1136	501	0	0	0	0	0	0	675	1350
BPA Monthly Surpluses/Deficits	1341	351	636	3250	2451	5103	4538	5917	3942	5493	1667	365

Storage Transactions:

	Oct '03	Nov '03	Dec '03	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	Jul '04	Aug '04	Sep '04
BPA Deficit Amount	0	0	0	0	0	0	0	0	0	0	0	0
Energy Released From NTS	0	0	0	0	0	0	0	0	0	675	675	0
BPA Surplus Amount	1341	351	636	3250	2451	5103	4538	5917	3942	5493	1667	365
Energy Stored in NTS	675	351	636	501	0	0	0	0	0	0	0	365
Ending Monthly Non-Treaty Storage Balance (MW-Mo)	1313	1664	2299	2800	2800	2800	2800	2800	2800	2125	1450	1815

Results

	Oct '03	Nov '03	Dec '03	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	Jul '04	Aug '04	Sep '04
Non-Treaty Storage Transactions	**675**	**351**	**636**	**501**	**0**	**0**	**0**	**0**	**0**	**-675**	**-675**	**365**

Table 6.11: Example of Non-Treaty Storage Operations for FY 2005 (Continued)

Non-Treaty Storage Operation (FY 2005)

NOTE: Logic for July and August forces release of Non-Treaty Storage to comport with fish operations for these months

	Oct '04	Nov '04	Dec '04	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	Jul '05	Aug '05	Sep '05
Monthly Maximum Storage Constraints (MW-Mo)	675	675	1350	1350	1350	675	270	675	675	0	0	675
Monthly Maximum Release Constraints (MW-Mo)	675	675	270	675	675	675	0	0	0	675	675	675
Month Number	1	2	3	4	5	6	7	8	9	10	11	12
Beginning Monthly Non-Treaty Storage Balance (MW-Mo)	**1815**	2490	2800	2800	2800	2125	2415	2415	2800	2800	2125	1450
Amount of Remaining Storage (MW-Mo)	985	310	0	0	0	675	385	385	0	0	675	1350
BPA Monthly Surpluses/Deficits	2101	752	682	330	-1194	290	-408	903	3595	1854	1947	947

Storage Transactions:

	Oct '04	Nov '04	Dec '04	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	Jul '05	Aug '05	Sep '05
BPA Deficit Amount	0	0	0	0	-1194	0	-408	0	0	0	0	0
Energy Released From NTS	0	0	0	0	675	0	0	0	0	675	675	0
BPA Surplus Amount	2101	752	682	330	0	290	0	903	3595	1854	1947	947
Energy Stored in NTS	675	310	0	0	0	290	0	385	0	0	0	675
Ending Monthly Non-Treaty Storage Balance (MW-Mo)	2490	2800	2800	2800	2125	2415	2415	2800	2800	2125	1450	2125

Results

	Oct '04	Nov '04	Dec '04	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	Jul '05	Aug '05	Sep '05
Non-Treaty Storage Transactions	**675**	**310**	**0**	**0**	**-675**	**290**	**0**	**385**	**0**	**-675**	**-675**	**675**

Table 6.11: Example of Non-Treaty Storage Operations for FY 2006 (Continued)

Non-Treaty Storage Operation (FY 2006)

NOTE: Logic for July and August forces release of Non-Treaty Storage to comport with fish operations for these months

	Oct '05	Nov '05	Dec '05	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06
Monthly Maximum Storage Constraints (MW-Mo)	675	675	1350	1350	1350	675	270	675	675	0	0	675
Monthly Maximum Release Constraints (MW-Mo)	675	675	270	675	675	675	0	0	0	675	675	675
Month Number	1	2	3	4	5	6	7	8	9	10	11	12
Beginning Monthly Non-Treaty Storage Balance (MW-Mo)	**2125**	2800	2800	2800	2125	1992	1317	1587	2262	2800	2125	1450
Amount of Remaining Storage (MW-Mo)	675	0	0	0	675	808	1483	1213	538	0	675	1350
BPA Monthly Surpluses/Deficits	1021	1494	610	-1480	-133	-736	627	916	2561	2349	1562	606

Storage Transactions:

	Oct '05	Nov '05	Dec '05	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06
BPA Deficit Amount	0	0	0	-1480	-133	-736	0	0	0	0	0	0
Energy Released From NTS	0	0	0	675	133	675	0	0	0	675	675	0
BPA Surplus Amount	1021	1494	610	0	0	0	627	916	2561	2349	1562	606
Energy Stored in NTS	675	0	0	0	0	0	270	675	538	0	0	606
Ending Monthly Non-Treaty Storage Balance (MW-Mo)	2800	2800	2800	2125	1992	1317	1587	2262	2800	2125	1450	2056

Results

	Oct '05	Nov '05	Dec '05	Jan '06	Feb '06	Mar '06	Apr '06	May '06	Jun '06	Jul '06	Aug '06	Sep '06
Non-Treaty Storage Transactions	**675**	**0**	**0**	**-675**	**-133**	**-675**	**270**	**675**	**538**	**-675**	**-675**	**606**

6.17.2 Surplus Energy Sales and Revenues. After computing all monthly HLH and LLH loads and resources, including Slice and storage into Non-Treaty Storage, when the Federal System has surplus energy, RevSim sells all the surplus energy at the HLH and LLH electricity prices estimated by AURORA. Tables 6.12 and 6.13 contain statistical information on the FY 2003-2006 annual surplus energy sales and revenues computed by RevSim.

6.17.3 Power Purchases and Expenses. After computing all monthly HLH and LLH loads and resources, including Slice and withdrawal from Non-Treaty Storage, when the Federal System is deficit, RevSim purchases the energy deficit at the HLH and LLH electricity prices estimated by AURORA. Tables 6.14 and 6.15 contain statistical information on the FY 2003-2006 annual power purchases and expenses computed by RevSim.

6.17.4 4(h)(10)(C) Credits. The 4(h)(10)(C) credit is a provision in the 1980 Pacific Northwest Electric Power Planning and Conservation Act that allows BPA and its ratepayers to receive a credit for non-power fish and wildlife impacts attributable to the Federal projects. The amount of 4(h)(10)(C) credits that BPA can collect for each of the 50 water years for FY 2003-2006 is determined by summing the costs of the operational impacts, the expenses, and the capital costs associated with fish and wildlife mitigation measures, and then multiplying the total cost by 22.3 percent.

The costs of the operational impacts are calculated for each of the 50 water years in RiskMod for FY 2003-2006 by multiplying HLH and LLH electricity prices from AURORA by the amount of power purchases (aMW) that qualifies for 4(h)(10)(C) credits. The amounts of power purchases (aMW) that qualifies for 4(h)(10)(C) credits is derived external to RevSim, but are used in RevSim to calculate the dollar amount of the 4(h)(10)(C) credits. *See* Loads and Resources Study (Chapter 2 of the Study), regarding the amount of power purchases (aMW) that qualifies for 4(h)(10)(C) credits.

Table 6.12: Forecasted Surplus Sales (aMW)					
	FY 2003	**FY 2004**	**FY 2005**	**FY 2006**	**4 Yr Average**
Average	722	2,440	2,590	2,523	2,069
Median	567	2,469	2,628	2,565	
StDev	326	942	970	967	
1% <=	385	676	767	705	
2.5% <=	410	733	839	794	
5% <=	430	791	930	875	
10% <=	455	951	1,104	1,066	
15% <=	473	1,308	1,428	1,334	
20% <=	487	1,502	1,667	1,611	
25% <=	500	1,813	1,891	1,851	
30% <=	513	2,022	2,068	2,011	
35% <=	526	2,183	2,240	2,152	
40% <=	539	2,294	2,414	2,308	
45% <=	553	2,383	2,522	2,443	
50% <=	567	2,469	2,628	2,565	
55% <=	585	2,565	2,717	2,664	
60% <=	607	2,672	2,841	2,788	
65% <=	704	2,806	3,002	2,938	
70% <=	864	2,944	3,130	3,062	
75% <=	906	3,087	3,295	3,227	
80% <=	946	3,332	3,536	3,453	
85% <=	1,016	3,572	3,744	3,649	
90% <=	1,224	3,723	3,924	3,861	
95% <=	1,453	3,968	4,135	4,062	
97.5% <=	1,593	4,108	4,258	4,195	
99% <=	1,734	4,198	4,363	4,310	

Table 6.13: Forecasted Surplus Sales Revenues ($ Thousand)

	FY 2003	FY 2004	FY 2005	FY 2006	4 Yr Average
Average	251,017	541,142	558,858	533,981	471,249
Median	224,275	550,412	556,130	534,824	
StDev	105,276	177,647	178,390	166,358	
1% <=	102,944	180,201	217,328	209,935	
2.5% <=	112,900	206,561	239,256	228,860	
5% <=	123,108	238,059	268,540	259,144	
10% <=	139,269	281,385	310,758	302,788	
15% <=	152,858	333,802	353,580	348,738	
20% <=	163,705	380,948	397,688	388,224	
25% <=	174,278	419,389	437,346	419,216	
30% <=	184,408	455,693	469,639	449,857	
35% <=	192,754	481,978	493,068	473,166	
40% <=	202,636	505,019	516,141	494,139	
45% <=	211,567	529,869	536,346	514,914	
50% <=	224,275	550,412	556,130	534,824	
55% <=	236,905	570,712	577,968	552,861	
60% <=	250,355	591,844	601,600	573,222	
65% <=	268,248	612,965	623,050	596,645	
70% <=	288,967	635,687	645,084	616,054	
75% <=	311,555	664,348	673,131	641,607	
80% <=	335,922	692,686	705,164	672,322	
85% <=	362,624	722,181	744,001	702,852	
90% <=	400,517	763,595	791,932	746,152	
95% <=	460,178	826,332	860,515	813,788	
97.5% <=	510,149	880,014	918,268	872,675	
99% <=	556,732	960,198	988,987	946,302	

Table 6.14: Forecasted Power Purchases (aMW)					
	FY 2003	**FY 2004**	**FY 2005**	**FY 2006**	**4 Yr Average**
Average	75	29	18	35	39
Median	66	18	4	14	
StDev	63	28	31	50	
1% <=	0	0	0	0	
2.5% <=	0	0	0	0	
5% <=	0	0	0	0	
10% <=	3	4	0	0	
15% <=	8	9	0	0	
20% <=	13	10	0	0	
25% <=	20	12	0	1	
30% <=	27	13	0	4	
35% <=	37	14	0	6	
40% <=	45	16	1	9	
45% <=	56	17	3	12	
50% <=	66	18	4	14	
55% <=	76	20	7	18	
60% <=	83	23	9	21	
65% <=	92	27	11	27	
70% <=	102	31	14	33	
75% <=	114	35	19	44	
80% <=	127	42	28	64	
85% <=	142	53	43	86	
90% <=	160	69	65	112	
95% <=	187	92	91	148	
97.5% <=	225	111	112	182	
99% <=	270	137	137	212	

Table 6.15: Forecasted Power Purchase Expenses ($ Thousand)

	FY 2003	FY 2004	FY 2005	FY 2006	4 Yr Average
Average	28,351	10,572	6,278	12,443	14,411
Median	23,231	6,449	1,513	4,496	
StDev	24,387	11,579	11,112	19,424	
1% <=	0	0	0	0	
2.5% <=	0	0	0	0	
5% <=	0	0	0	0	
10% <=	963	1,183	0	0	
15% <=	2,705	2,531	0	0	
20% <=	5,074	3,239	0	0	
25% <=	7,807	3,777	0	277	
30% <=	10,853	4,251	0	1,121	
35% <=	14,081	4,774	0	1,901	
40% <=	17,290	5,276	213	2,707	
45% <=	20,418	5,867	861	3,615	
50% <=	23,231	6,449	1,513	4,496	
55% <=	26,300	7,175	2,346	5,606	
60% <=	29,960	8,124	3,138	7,072	
65% <=	33,762	9,270	4,149	8,726	
70% <=	38,603	10,732	5,150	10,724	
75% <=	42,943	12,972	6,472	14,362	
80% <=	48,682	15,621	9,199	19,958	
85% <=	55,751	20,218	13,465	28,209	
90% <=	63,207	25,490	21,546	38,524	
95% <=	75,426	36,078	30,424	54,184	
97.5% <=	84,920	44,459	39,740	69,908	
99% <=	97,375	54,013	52,946	93,765	

For FY 2003, the operational portion of the 4(h)(10)(C) credits were computed based on actual Mid-C prices for October through December and AURORA prices for January through September. Also, since the operational portion of the credit is impacted by the power purchase amount (aMW) needed for each water condition, the 4(h)(10)(C) credits for FY 2003 were affected by the water year weights used for FY 2003.

The capital costs used in RevSim for FY 2003-2006 are $20.0, $24.0, $26.0, and $28.0 million and the expenses are $154.0, $134.4, $139.0, and $143.7 million. Statistical information on the 4(h)(10)(C) credits, by Fiscal Year, are reported in Table 6.16.

6.17.5 FCCF. The FCCF credit is related to the 4(h)(10)(C) credit. It is an agreement between BPA and the Office of Management and Budget implemented to allow BPA and its ratepayers to obtain limited credit for non-power fish and wildlife impacts that occurred prior to 1995. The original amount of the FCCF reserve was $325 million. The remaining amount of this reserve, after BPA claimed $246 million in FCCF credits in FY 2001, is $79 million. The amount of annual FCCF credits that BPA can claim, if there were no limitations in the reserve balance of the FCCF, for each of the 50 water years for FY 2003-2006 are calculated external to RevSim. These values were calculated for the 2002 Final Power Rate Proposal, May 2000, in a spreadsheet using monthly surplus energy revenues and power purchase expenses for each of the 50 water years. The calculations in the spreadsheet produce a 50 (50 water years) X 4 (FY 2003-2006) table of annual FCCF credits that were input into RevSim. The 50 X 4 matrices of FCCF credits for FY 2003-2006 are reported in Table 6.17. A description of the FCCF and the process used to calculate the credits are reported in the 2002 Final Power Rate Proposal, May 2000, Revenue Requirement Study Documentation, WP-02-E-BPA-02A.

Table 6.16: 4(h)(10)(c) Credit Statistics ($ Thousand)				
	FY 2003	**FY 2004**	**FY 2005**	**FY 2006**
Average	123,671	66,915	66,745	67,338
Median	126,819	59,366	60,718	60,649
StDev	24,229	24,857	22,291	22,663
1% <=	77,982	34,281	35,803	37,239
2.5% <=	81,604	34,522	35,863	37,239
5% <=	83,657	37,727	39,099	40,231
10% <=	92,694	41,453	42,889	43,553
15% <=	97,092	45,604	46,934	47,654
20% <=	99,360	48,717	49,859	50,380
25% <=	101,606	50,494	52,025	52,305
30% <=	104,246	52,380	53,901	53,892
35% <=	108,774	53,843	55,286	55,325
40% <=	115,100	55,493	56,752	57,192
45% <=	121,136	57,407	58,452	58,914
50% <=	126,797	59,363	60,704	60,646
55% <=	131,812	61,356	62,615	62,691
60% <=	135,523	63,947	65,252	65,261
65% <=	138,704	67,208	68,275	68,142
70% <=	141,627	71,187	71,771	71,923
75% <=	144,127	76,847	76,634	77,282
80% <=	146,947	84,815	83,289	83,916
85% <=	149,876	95,358	91,472	93,597
90% <=	153,050	107,361	101,986	102,863
95% <=	158,415	120,757	113,608	115,328
97.5% <=	163,062	129,350	122,687	123,130
99% <=	167,946	138,537	129,921	134,675

Table 6.17: Annual FCCF Credit Algorithm ($ Million)

Beginning Reserve Balance	79.0	**79.0**	**Ending Reserve Level**
Credit for Fiscal year '02 :	0.0	**79.0**	
Credit for Fiscal year '03 :	79.0	**0.0**	
Credit for Fiscal year '04 :	0.0	**0.0**	
Credit for Fiscal year '05 :	0.0	**0.0**	
Credit for Fiscal year '06 :	0.0	**0.0**	

Note: Beginning Reserve Balance Reflects Potential Reserve Reductions during FY2001

Water Year	Reserves Beginning FY02	FY 02	FY 03	FY 04	FY 05	FY 06
1929	79.00	0.00	332.91	355.19	367.04	391.77
1930	79.00	0.00	343.84	352.59	379.79	401.18
1931	79.00	0.00	418.30	458.40	451.51	485.82
1932	79.00	0.00	145.04	170.85	186.12	205.24
1933	79.00	0.00	0.00	0.00	0.00	0.00
1934	79.00	0.00	0.00	0.00	0.00	0.00
1935	79.00	0.00	0.00	0.00	0.00	0.00
1936	79.00	0.00	131.70	168.33	153.32	181.47
1937	79.00	0.00	397.69	409.54	437.21	459.30
1938	79.00	0.00	4.11	11.07	9.34	20.71
1939	79.00	0.00	115.15	133.64	139.55	153.04
1940	79.00	0.00	142.79	148.75	150.80	178.42
1941	79.00	0.00	271.56	266.89	288.40	315.09
1942	79.00	0.00	0.00	0.00	0.00	0.00
1943	79.00	0.00	0.00	0.00	0.00	0.00
1944	79.00	0.00	363.76	378.71	402.85	438.70
1945	79.00	0.00	297.52	312.86	330.44	349.63
1946	79.00	0.00	0.00	0.00	0.00	0.00
1947	79.00	0.00	0.00	0.00	0.00	0.00
1948	79.00	0.00	0.00	0.00	0.00	0.00
1949	79.00	0.00	48.22	68.74	52.15	93.19
1950	79.00	0.00	0.00	0.00	0.00	0.00
1951	79.00	0.00	0.00	0.00	0.00	0.00
1952	79.00	0.00	0.00	0.00	0.00	0.00
1953	79.00	0.00	0.00	0.00	0.00	0.00
1954	79.00	0.00	0.00	0.00	0.00	0.00
1955	79.00	0.00	0.00	0.00	0.00	0.00
1956	79.00	0.00	0.00	0.00	0.00	0.00
1957	79.00	0.00	0.00	0.00	0.00	0.00
1958	79.00	0.00	0.00	0.00	0.00	0.00
1959	79.00	0.00	0.00	0.00	0.00	0.00
1960	79.00	0.00	0.00	0.00	0.00	0.00
1961	79.00	0.00	0.00	0.00	0.00	0.00
1962	79.00	0.00	0.00	0.00	0.00	0.00
1963	79.00	0.00	0.00	0.00	0.00	0.00
1964	79.00	0.00	0.00	0.00	0.00	0.00
1965	79.00	0.00	0.00	0.00	0.00	0.00
1966	79.00	0.00	0.00	0.00	0.00	0.00
1967	79.00	0.00	0.00	0.00	0.00	0.00
1968	79.00	0.00	0.00	0.00	0.00	0.00
1969	79.00	0.00	0.00	0.00	0.00	0.00
1970	79.00	0.00	0.00	0.00	0.00	0.00
1971	79.00	0.00	0.00	0.00	0.00	0.00
1972	79.00	0.00	0.00	0.00	0.00	0.00
1973	79.00	0.00	130.88	131.87	132.75	145.13
1974	79.00	0.00	0.00	0.00	0.00	0.00
1975	79.00	0.00	0.00	0.00	0.00	0.00
1976	79.00	0.00	0.00	0.00	0.00	0.00
1977	79.00	0.00	356.81	368.44	394.04	427.02
1978	79.00	0.00	0.00	0.00	0.00	0.00
AVERAGE	**79.0**	**0.0**	**70.0**	**74.7**	**77.5**	**84.9**

The FCCF credits for each of the 50 water years, given the limitation in the FCCF reserve balance of $79 million, are determined by running RiskMod. These FCCF values are determined by inputting into RevSim the annual FCCF credits for each of the 50 water years for FY 2003-2006, inputting the FCCF reserve balance of $79 million at the beginning of FY 2003, and running RiskMod. Since the FCCF credit is affected by the water year for each simulation, the FCCF credit for FY 2003 is affected by the water year weights used for FY 2003. Statistical information on the FCCF credits, by Fiscal Year, are reported in Table 6.18.

6.18 Results from RiskMod

Table 6.19 contains detailed statistical information about the net revenue distributions from RiskMod for FY 2003-2006. These net revenues reflect revenues from the LB CRAC rate and FB CRAC rate (the FB CRAC is assumed to trigger by the full amount in all FYs), but do not reflect revenues from the SN CRAC rate, which is computed in the ToolKit Model. *See* Chapter 7 of the Study, regarding the ToolKit Model. Tables 6.20 through 6.55 contain detailed monthly statistics on HLH and LLH surplus energy sales, surplus energy revenues, power purchases, and power purchase expenses.

Table 6.18: FCCF Credit Statistics ($ Thousand)

	FY 2003	FY 2004	FY 2005	FY 2006
Average	69,136	2,942	1,462	774
Median	79,000	0	0	0
StDev	26,000	14,693	10,245	7,750
1% <=	0	0	0	0
2.5% <=	0	0	0	0
5% <=	0	0	0	0
10% <=	0	0	0	0
15% <=	79,000	0	0	0
20% <=	79,000	0	0	0
25% <=	79,000	0	0	0
30% <=	79,000	0	0	0
35% <=	79,000	0	0	0
40% <=	79,000	0	0	0
45% <=	79,000	0	0	0
50% <=	79,000	0	0	0
55% <=	79,000	0	0	0
60% <=	79,000	0	0	0
65% <=	79,000	0	0	0
70% <=	79,000	0	0	0
75% <=	79,000	0	0	0
80% <=	79,000	0	0	0
85% <=	79,000	0	0	0
90% <=	79,000	0	0	0
95% <=	79,000	0	0	0
97.5% <=	79,000	79,000	0	0
99% <=	79,000	79,000	79,000	0

Table 6.19: Net Revenue Statistics ($ Thousand)

	FY 2003	FY 2004	FY 2005	FY 2006	4 Yr Average
Average	-190,883	-123,066	-117,131	-99,444	-132,631
Median	-204,637	-120,311	-122,650	-102,269	
StDev	94,574	168,011	175,944	172,009	
1% <=	-355,479	-467,622	-461,582	-425,399	
2.5% <=	-339,870	-437,094	-421,109	-406,065	
5% <=	-327,480	-400,681	-386,893	-373,665	
10% <=	-305,950	-354,920	-348,063	-322,991	
15% <=	-287,003	-310,763	-309,911	-285,943	
20% <=	-271,359	-273,620	-272,550	-252,771	
25% <=	-257,149	-241,268	-243,691	-221,191	
30% <=	-245,150	-209,070	-213,918	-195,175	
35% <=	-235,447	-185,379	-188,289	-170,144	
40% <=	-225,130	-163,158	-168,080	-147,404	
45% <=	-215,920	-141,035	-147,935	-123,592	
50% <=	-204,646	-120,524	-122,779	-102,298	
55% <=	-192,073	-99,743	-100,452	-81,527	
60% <=	-178,646	-79,063	-78,253	-59,951	
65% <=	-165,255	-59,902	-54,079	-40,224	
70% <=	-150,947	-34,009	-30,918	-15,263	
75% <=	-131,947	-6,788	-7,159	9,687	
80% <=	-111,782	18,393	21,510	36,003	
85% <=	-87,824	49,294	62,115	74,712	
90% <=	-59,930	88,879	114,866	120,906	
95% <=	-22,254	151,538	190,330	197,776	
97.5% <=	12,438	210,078	251,826	268,951	
99% <=	59,406	286,407	337,209	352,858	

Table 6.20: Forecasted HLH Surplus Sales Statistics For FY 2004 (aMW)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Annual
Average	1,628	652	873	3,187	2,432	2,612	2,987	4,494	5,128	4,816	3,703	881	2,788
Median	1,431	574	447	3,045	2,183	2,900	3,041	4,850	5,624	5,106	3,710	547	2,864
StDev	857	219	1,122	2,244	2,239	1,957	1,793	1,879	1,899	1,497	981	993	984
1%	422	393	0	0	0	0	0	263	931	1,712	1,868	12	828
2.5%	448	419	0	0	0	0	0	375	1,139	1,884	2,008	50	903
5%	515	436	88	0	0	0	0	835	1,534	2,176	2,189	84	971
10%	710	464	226	50	0	0	196	1,187	2,244	2,693	2,427	125	1,139
15%	867	481	308	191	0	19	660	2,001	2,603	2,958	2,583	165	1,593
20%	974	494	339	540	0	189	1,355	2,700	3,039	3,192	2,712	201	1,846
25%	1,052	506	357	1,365	0	350	1,665	3,517	3,909	3,408	2,848	238	2,182
30%	1,118	518	375	1,721	0	830	1,941	3,939	4,205	3,715	2,999	287	2,422
35%	1,198	529	393	2,006	837	1,561	2,123	4,293	4,541	4,460	3,153	337	2,580
40%	1,278	543	410	2,354	1,243	2,130	2,385	4,472	5,079	4,779	3,367	403	2,705
45%	1,352	557	429	2,727	1,730	2,597	2,737	4,617	5,380	4,971	3,547	467	2,792
50%	1,431	574	447	3,045	2,183	2,900	3,041	4,850	5,624	5,106	3,710	547	2,864
55%	1,513	595	463	3,388	2,804	3,117	3,297	5,117	5,896	5,264	3,871	639	2,946
60%	1,630	619	480	3,820	3,197	3,398	3,734	5,429	6,062	5,471	4,105	752	3,047
65%	1,770	649	501	4,363	3,416	3,670	3,989	5,652	6,199	5,742	4,262	853	3,186
70%	1,874	686	560	4,869	3,656	4,051	4,215	5,841	6,377	5,902	4,373	970	3,324
75%	2,027	732	696	5,177	4,006	4,347	4,467	6,017	6,582	6,036	4,496	1,104	3,503
80%	2,246	803	988	5,557	4,517	4,557	4,792	6,131	6,798	6,235	4,636	1,255	3,701
85%	2,479	871	1,463	6,016	5,337	4,736	5,065	6,249	7,091	6,406	4,782	1,591	3,951
90%	2,694	953	2,525	6,321	6,008	4,911	5,392	6,497	7,315	6,551	4,954	1,827	4,139
95%	3,328	1,080	3,892	6,593	6,458	5,660	5,666	6,797	7,512	6,801	5,273	3,851	4,248
97.5%	3,985	1,246	4,733	7,014	6,593	6,144	5,878	7,058	7,880	6,991	5,461	4,141	4,336
99%	4,678	1,493	5,099	7,190	6,748	6,407	6,108	7,269	8,238	7,278	5,627	4,612	4,421

Table 6.21: Forecasted HLH Surplus Sales Revenue Statistics For FY 2004 ($ Thousand)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	27,440	12,386	15,550	47,955	32,060	31,425	32,074	37,725	32,996	45,665	50,188	11,519	376,983
Median	25,316	11,126	8,657	50,819	31,340	34,498	35,057	39,080	33,768	44,135	49,002	8,159	381,071
StDev	13,198	5,116	18,675	31,385	29,166	23,527	16,985	17,160	10,253	12,310	13,881	10,444	120,758
1%	6,911	5,447	0	0	0	0	0	4,190	9,993	21,600	23,427	166	131,501
2.5%	8,201	6,139	0	0	0	0	0	5,970	12,570	24,215	26,709	670	149,883
5%	9,885	6,719	1,760	0	0	0	0	12,080	14,908	27,654	29,311	1,262	170,475
10%	12,487	7,424	4,012	1,060	0	0	3,224	16,249	18,474	31,540	33,370	1,952	201,337
15%	14,584	7,988	5,015	4,080	0	268	9,511	18,890	21,698	34,926	36,008	2,540	239,483
20%	16,450	8,509	5,649	11,447	0	2,402	17,245	21,378	24,260	36,875	38,086	3,156	271,154
25%	18,059	8,904	6,219	25,736	0	5,386	22,232	23,423	26,690	38,466	40,207	3,686	296,130
30%	19,290	9,363	6,702	31,904	0	11,513	25,616	25,465	28,670	39,830	42,112	4,430	318,983
35%	20,712	9,788	7,161	37,852	11,137	20,696	28,307	27,737	30,234	40,973	44,013	5,198	337,058
40%	22,169	10,263	7,594	42,745	18,888	26,323	30,827	30,393	31,465	42,111	45,717	6,113	352,864
45%	23,837	10,653	8,116	47,220	25,412	30,691	33,394	34,957	32,585	43,057	47,310	7,054	367,216
50%	25,316	11,126	8,657	50,819	31,340	34,498	35,057	39,080	33,768	44,135	49,002	8,159	381,071
55%	26,659	11,594	9,262	54,078	36,292	37,363	36,615	41,644	34,846	45,453	50,722	9,439	394,734
60%	28,320	12,180	10,016	57,247	40,562	40,295	38,233	44,242	36,098	46,599	52,579	10,762	409,219
65%	30,097	12,790	10,952	60,523	44,985	43,359	39,821	46,390	37,136	47,765	54,716	12,426	424,296
70%	31,695	13,572	12,279	64,091	49,103	46,033	41,385	48,341	38,317	49,245	56,451	14,015	440,274
75%	34,113	14,312	14,296	68,270	53,985	48,463	43,071	50,661	39,524	51,004	58,484	16,234	457,876
80%	37,281	15,378	18,179	72,820	59,133	51,927	45,000	52,949	40,865	53,532	61,175	18,594	476,887
85%	41,082	16,966	28,042	78,986	64,685	55,938	48,046	55,809	42,156	56,877	64,157	21,697	498,719
90%	45,933	19,121	41,176	86,125	71,281	60,823	51,295	59,505	43,919	60,965	68,333	25,603	528,344
95%	52,697	23,021	59,667	100,016	80,961	69,024	57,603	64,728	48,257	68,540	75,142	32,749	575,901
97.5%	59,101	25,893	74,376	111,341	89,635	76,245	62,174	70,052	53,899	75,605	81,572	40,475	611,170
99%	66,345	30,304	90,831	124,003	105,783	82,029	69,695	76,425	61,031	84,370	87,627	46,522	675,736

Table 6.22: Forecasted LLH Surplus Sales Statistics For FY 2004 (aMW)													
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**June**	**July**	**Aug**	**Sep**	**Annual**
Average	752	60	150	2,239	2,058	1,626	2,467	3,696	3,647	3,682	2,767	536	1,976
Median	650	4	0	1,588	1,710	1,485	2,149	3,631	3,228	3,342	2,637	334	1,938
StDev	534	97	464	2,183	1,869	1,449	1,725	2,304	2,147	1,748	854	577	910
1%	0	0	0	0	0	0	0	0	135	1,337	1,376	0	448
2.5%	10	0	0	0	0	0	0	11	417	1,473	1,510	15	497
5%	71	0	0	0	0	0	18	181	691	1,648	1,652	43	553
10%	150	0	0	0	0	117	144	527	1,008	1,861	1,846	80	683
15%	254	0	0	41	16	169	393	1,130	1,441	1,994	1,972	114	948
20%	344	0	0	174	91	214	754	1,637	1,676	2,110	2,074	142	1,073
25%	397	0	0	304	158	349	1,093	2,026	2,155	2,248	2,162	174	1,291
30%	454	0	0	509	279	429	1,277	2,244	2,395	2,393	2,233	201	1,471
35%	504	0	0	776	746	671	1,481	2,439	2,612	2,635	2,314	231	1,608
40%	552	0	0	997	1,122	924	1,778	2,581	2,786	2,946	2,398	265	1,716
45%	596	0	0	1,270	1,445	1,239	1,973	2,749	3,014	3,146	2,501	295	1,813
50%	650	4	0	1,588	1,710	1,485	2,149	3,631	3,228	3,342	2,637	334	1,938
55%	702	20	0	1,865	2,126	1,640	2,543	3,932	3,358	3,467	2,781	393	2,084
60%	767	35	0	2,193	2,381	1,852	2,832	4,082	3,544	3,592	2,900	453	2,195
65%	845	50	0	2,643	2,784	2,061	3,151	4,583	3,980	3,801	2,998	520	2,293
70%	925	66	0	3,097	3,131	2,267	3,622	5,099	4,293	4,218	3,105	603	2,407
75%	1,008	84	0	3,590	3,447	2,481	4,099	5,470	5,495	4,683	3,211	697	2,542
80%	1,112	107	0	4,399	3,861	2,768	4,291	6,344	6,166	5,201	3,344	796	2,820
85%	1,237	139	0	5,269	4,235	2,999	4,482	6,880	6,491	5,726	3,552	977	3,060
90%	1,367	188	581	5,708	5,065	3,310	4,802	7,159	6,795	6,536	3,827	1,173	3,175
95%	1,720	271	1,344	6,565	5,484	4,034	5,351	7,412	7,466	7,296	4,354	1,898	3,603
97.5%	2,220	352	1,894	7,230	5,969	5,448	5,661	7,574	8,180	7,843	4,622	2,169	3,911
99%	2,811	436	2,295	7,663	6,232	6,713	6,300	7,712	8,524	8,133	5,943	3,066	4,149

Table 6.23: Forecasted LLH Surplus Sales Revenue Statistics For FY 2004 ($ Thousand)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	8,433	704	1,434	17,636	17,046	12,209	17,783	20,452	12,398	23,006	27,222	5,836	164,158
Median	7,538	48	0	17,366	16,424	11,962	18,847	21,898	12,609	22,778	26,411	3,819	166,893
StDev	5,693	1,180	4,396	13,796	14,536	9,320	10,654	9,549	4,591	5,781	8,168	5,878	59,479
1%	0	0	0	0	0	0	0	0	992	10,574	12,257	0	46,743
2.5%	106	0	0	0	0	0	0	95	3,041	12,010	14,120	194	54,383
5%	863	0	0	0	0	0	169	1,684	4,834	13,722	15,531	476	64,096
10%	1,886	0	0	0	0	928	1,493	4,758	6,820	15,551	17,621	907	79,802
15%	2,942	0	0	530	161	1,620	3,792	9,209	8,101	17,078	19,061	1,303	94,489
20%	3,813	0	0	2,282	924	2,197	6,775	12,746	9,034	18,232	20,286	1,648	108,628
25%	4,594	0	0	4,176	1,728	3,039	9,265	15,308	9,792	19,144	21,322	1,961	120,959
30%	5,205	0	0	6,396	2,986	4,187	11,377	16,569	10,473	19,898	22,294	2,264	132,363
35%	5,711	0	0	9,028	6,808	5,969	13,327	17,936	11,079	20,662	23,322	2,591	141,210
40%	6,362	0	0	11,662	10,650	8,254	15,219	19,064	11,662	21,336	24,358	2,962	150,236
45%	6,882	0	0	14,589	13,444	10,061	17,236	20,505	12,096	22,038	25,382	3,360	158,691
50%	7,538	48	0	17,366	16,424	11,962	18,847	21,898	12,609	22,778	26,411	3,819	166,893
55%	8,107	233	0	19,765	18,771	13,453	20,714	23,192	13,009	23,399	27,358	4,349	174,303
60%	8,734	423	0	22,248	21,430	14,942	22,249	24,295	13,439	24,082	28,455	5,033	181,119
65%	9,449	578	0	24,696	23,839	16,478	23,633	25,301	13,891	24,867	29,541	5,841	189,517
70%	10,224	778	0	26,968	26,300	17,836	24,767	26,423	14,303	25,688	30,717	6,827	198,247
75%	11,147	991	0	28,528	28,609	19,252	25,868	27,408	14,699	26,761	32,043	7,918	207,207
80%	12,401	1,217	0	30,477	31,128	20,692	27,038	28,388	15,274	28,141	33,600	9,232	218,086
85%	13,925	1,567	0	32,622	33,567	22,635	28,676	29,483	16,011	29,488	35,486	10,870	228,737
90%	16,081	2,179	5,979	35,728	36,520	25,311	30,737	31,104	17,227	30,848	37,950	12,982	240,182
95%	19,181	3,137	12,900	40,033	41,350	28,571	33,519	33,787	19,497	32,836	41,621	17,683	259,578
97.5%	22,543	4,258	16,609	45,021	45,817	30,488	36,705	36,335	22,912	34,377	45,863	22,294	272,312
99%	26,595	5,433	20,919	49,520	51,200	33,175	41,391	39,812	27,174	35,985	50,701	27,839	292,674

Table 6.24: Forecasted Total Surplus Sales Statistics For FY 2004 (aMW)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	1,252	398	563	2,780	2,272	2,189	2,765	4,152	4,493	4,330	3,302	733	2,440
Median	1,101	335	256	2,444	1,971	2,309	2,679	4,405	4,692	4,367	3,257	453	2,469
StDev	717	157	831	2,184	2,068	1,709	1,750	2,003	1,922	1,545	910	811	942
1%	273	247	0	0	0	41	0	150	582	1,593	1,658	86	676
2.5%	289	259	0	0	0	57	0	249	826	1,741	1,802	98	733
5%	317	268	50	29	0	69	39	574	1,153	1,971	1,967	110	791
10%	471	277	129	84	0	92	154	855	1,713	2,348	2,179	126	951
15%	612	284	176	116	7	142	551	1,627	2,126	2,557	2,328	139	1,308
20%	707	290	194	360	40	168	1,119	2,256	2,439	2,743	2,445	159	1,502
25%	772	297	204	884	70	256	1,459	2,953	3,173	2,894	2,562	188	1,813
30%	833	303	214	1,197	145	583	1,710	3,219	3,476	3,110	2,677	233	2,022
35%	901	309	225	1,482	810	1,195	1,856	3,468	3,717	3,672	2,797	279	2,183
40%	964	316	234	1,803	1,232	1,606	2,024	3,654	4,063	4,006	2,928	333	2,294
45%	1,029	326	245	2,111	1,631	2,010	2,402	3,819	4,385	4,204	3,096	387	2,383
50%	1,101	335	256	2,444	1,971	2,309	2,679	4,405	4,692	4,367	3,257	453	2,469
55%	1,165	348	265	2,815	2,485	2,483	2,968	4,778	4,862	4,541	3,409	528	2,565
60%	1,255	366	274	3,093	2,879	2,720	3,331	5,078	5,007	4,748	3,592	624	2,672
65%	1,369	391	286	3,510	3,147	2,975	3,669	5,347	5,334	5,020	3,741	710	2,806
70%	1,470	416	320	4,136	3,474	3,268	3,979	5,512	5,860	5,229	3,846	815	2,944
75%	1,588	452	398	4,601	3,780	3,558	4,293	5,676	6,234	5,432	3,949	927	3,087
80%	1,752	487	564	4,987	4,181	3,822	4,597	6,015	6,628	5,696	4,076	1,057	3,332
85%	1,935	534	836	5,645	4,907	3,992	4,800	6,425	6,792	6,148	4,228	1,326	3,572
90%	2,126	602	1,701	6,085	5,424	4,172	5,068	6,752	6,945	6,505	4,477	1,546	3,723
95%	2,644	721	2,787	6,620	6,037	5,304	5,612	6,975	7,168	6,878	4,853	3,014	3,968
97.5%	3,230	839	3,517	6,943	6,286	5,637	5,831	7,111	7,352	7,159	5,066	3,284	4,108
99%	3,878	1,036	3,897	7,366	6,476	6,360	5,950	7,258	7,596	7,645	5,756	3,949	4,198

Table 6.25: Forecasted Total Surplus Sales Revenue Statistics For FY 2004 ($ Thousand)													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	35,872	13,090	16,984	65,592	49,106	43,635	49,857	58,177	45,394	68,670	77,410	17,355	541,142
Median	32,804	11,529	8,657	71,020	47,552	46,991	54,926	59,053	46,728	68,751	76,261	11,826	550,412
StDev	18,774	5,927	22,763	44,064	43,308	32,318	27,167	23,577	13,930	16,310	21,134	16,166	177,647
1%	7,657	5,820	0	0	0	823	0	4,233	12,474	32,701	36,623	2,211	180,201
2.5%	8,976	6,488	0	0	0	1,249	0	6,880	16,459	36,869	41,411	2,506	206,561
5%	10,949	7,023	1,760	1,037	0	1,601	839	15,367	20,971	41,891	45,124	2,854	238,059
10%	14,255	7,675	4,012	2,969	0	2,208	4,149	23,069	26,000	48,000	51,487	3,386	281,385
15%	17,639	8,195	5,015	4,459	161	3,189	13,327	33,007	29,883	52,510	55,560	3,806	333,802
20%	20,263	8,747	5,649	13,182	932	4,327	24,767	40,391	33,594	56,555	58,851	4,420	380,948
25%	22,585	9,196	6,219	29,973	1,852	6,498	32,634	45,073	36,946	59,758	62,125	5,246	419,389
30%	24,616	9,605	6,702	39,045	3,685	14,172	37,618	48,043	39,563	62,033	65,156	6,219	455,693
35%	26,580	10,132	7,161	47,058	17,849	26,861	41,998	51,248	41,797	64,033	67,957	7,467	481,978
40%	28,463	10,618	7,594	55,389	30,669	34,873	46,276	53,815	43,598	65,902	70,858	8,839	505,019
45%	30,732	11,063	8,116	64,519	39,880	41,279	50,544	56,404	45,259	67,397	73,604	10,291	529,869
50%	32,804	11,529	8,657	71,020	47,552	46,991	54,926	59,053	46,728	68,751	76,261	11,826	550,412
55%	34,900	11,960	9,262	75,896	55,372	51,531	58,006	61,956	48,163	70,127	78,820	13,619	570,712
60%	37,030	12,616	10,016	81,322	62,943	56,134	60,770	64,791	49,547	71,575	81,511	15,883	591,844
65%	39,339	13,350	10,952	85,455	68,879	60,746	63,565	68,199	51,214	72,893	84,593	18,231	612,965
70%	41,982	14,082	12,279	90,316	75,083	64,881	65,996	71,542	52,641	74,499	87,354	20,819	635,687
75%	45,143	14,908	14,296	95,818	82,098	68,622	68,678	74,808	54,200	76,365	90,195	24,289	664,348
80%	49,772	16,177	18,179	102,196	90,402	72,975	71,780	78,116	55,905	78,859	93,923	28,014	692,686
85%	55,013	18,010	28,456	108,746	98,253	77,671	75,498	81,656	57,534	82,289	98,755	32,657	722,181
90%	61,825	20,685	47,160	119,724	107,566	83,945	80,658	86,488	59,958	87,430	104,599	38,539	763,595
95%	71,486	25,175	71,445	136,790	121,398	95,806	90,065	94,138	66,881	96,986	114,134	51,518	826,332
97.5%	81,505	29,553	90,885	154,027	133,302	104,529	97,779	101,569	75,371	106,439	123,403	63,017	880,014
99%	92,207	35,204	109,911	167,972	154,110	112,836	108,673	109,210	80,763	117,359	135,180	73,032	960,198

Table 6.26: Forecasted HLH Surplus Sales Statistics For FY 2005 (aMW)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Annual
Average	2,107	1,388	1,509	3,880	2,483	2,795	2,907	4,074	5,435	4,570	3,784	903	2,994
Median	1,977	1,396	941	4,209	2,233	3,102	2,954	4,380	5,906	4,909	3,781	587	3,080
StDev	938	357	1,406	2,198	2,284	2,000	1,780	1,818	1,889	1,502	995	998	1,018
1%	618	567	75	0	0	0	0	162	1,222	1,486	1,932	26	964
2.5%	704	643	270	0	0	0	0	314	1,482	1,702	2,091	64	1,048
5%	820	784	386	0	0	0	0	470	2,010	1,947	2,259	94	1,153
10%	996	926	463	371	0	28	26	801	2,549	2,445	2,497	141	1,384
15%	1,164	1,032	530	1,022	0	95	645	1,646	2,952	2,735	2,655	182	1,684
20%	1,294	1,105	601	1,481	0	341	1,291	2,555	3,478	2,949	2,775	215	2,069
25%	1,437	1,171	657	2,328	0	661	1,569	3,051	4,139	3,165	2,907	255	2,320
30%	1,577	1,225	714	2,768	0	1,096	1,826	3,429	4,475	3,495	3,045	308	2,507
35%	1,704	1,271	773	2,973	818	1,717	2,057	3,960	4,858	4,004	3,232	366	2,688
40%	1,800	1,316	826	3,212	1,244	2,304	2,380	4,115	5,199	4,527	3,413	435	2,871
45%	1,881	1,356	881	3,767	1,665	2,811	2,700	4,223	5,662	4,738	3,606	506	2,994
50%	1,977	1,396	941	4,209	2,233	3,102	2,954	4,380	5,906	4,909	3,781	587	3,080
55%	2,070	1,438	1,011	4,553	2,864	3,394	3,152	4,619	6,110	5,050	3,992	674	3,171
60%	2,176	1,478	1,089	4,894	3,313	3,688	3,617	5,035	6,367	5,180	4,183	776	3,274
65%	2,313	1,515	1,185	5,241	3,526	3,954	3,910	5,212	6,533	5,358	4,343	890	3,447
70%	2,434	1,556	1,344	5,500	3,846	4,256	4,164	5,353	6,679	5,585	4,466	988	3,602
75%	2,592	1,602	1,978	5,707	4,197	4,538	4,382	5,479	6,838	5,761	4,593	1,120	3,763
80%	2,830	1,650	2,278	5,937	4,562	4,704	4,645	5,609	7,087	5,979	4,737	1,266	3,955
85%	3,018	1,718	2,618	6,283	5,418	4,903	4,942	5,749	7,389	6,212	4,879	1,572	4,180
90%	3,259	1,800	3,718	6,638	6,098	5,135	5,371	6,076	7,627	6,383	5,044	1,875	4,363
95%	3,875	1,928	4,973	6,939	6,515	5,806	5,632	6,342	7,861	6,690	5,384	3,873	4,523
97.5%	4,562	2,097	5,853	7,248	6,751	6,370	5,803	6,580	8,265	6,869	5,592	4,231	4,614
99%	5,252	2,484	6,237	7,468	6,894	6,667	5,916	6,784	8,719	7,077	5,791	4,668	4,715

Table 6.27: Forecasted HLH Surplus Sales Revenue Statistics For FY 2005 ($ Thousand)													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	32,044	24,371	28,381	62,753	26,265	30,261	28,354	26,367	30,157	46,545	46,082	10,770	392,349
Median	30,240	23,722	19,289	63,362	26,444	32,491	30,654	27,566	31,600	44,941	43,614	7,830	390,768
StDev	13,188	7,804	24,010	36,554	23,475	21,604	15,640	12,091	9,562	14,711	15,069	9,573	121,167
1%	9,818	8,843	1,551	0	0	0	0	2,358	9,768	18,677	23,826	352	160,705
2.5%	11,766	10,521	5,502	0	0	0	0	4,280	11,124	22,180	25,892	908	177,664
5%	13,521	12,335	7,190	0	0	0	0	6,512	12,760	25,181	28,320	1,413	195,589
10%	16,179	15,071	8,975	7,774	0	381	360	10,002	15,861	29,125	31,215	2,090	227,166
15%	18,560	16,609	10,412	19,416	0	1,353	8,281	12,526	18,614	32,839	33,507	2,623	255,788
20%	20,630	17,915	11,594	29,639	0	4,537	14,693	14,629	21,380	35,459	35,257	3,155	284,432
25%	22,306	19,100	12,917	39,496	0	8,435	18,600	16,483	23,722	37,281	36,857	3,768	308,541
30%	24,122	20,195	14,153	45,080	0	13,926	21,223	18,347	25,754	39,214	38,256	4,399	331,314
35%	25,617	21,054	15,339	49,531	9,492	20,383	23,698	20,334	27,901	40,629	39,616	5,081	345,792
40%	27,181	21,831	16,572	53,310	16,471	25,299	25,823	22,560	29,249	42,196	41,094	5,831	362,930
45%	28,773	22,801	17,850	58,560	21,337	29,230	28,437	25,619	30,498	43,719	42,333	6,839	377,964
50%	30,240	23,722	19,289	63,362	26,444	32,491	30,654	27,566	31,600	44,941	43,614	7,830	390,768
55%	31,948	24,761	20,719	68,024	30,145	35,301	32,918	29,406	32,618	46,505	45,201	9,021	403,872
60%	33,738	25,555	22,784	72,525	34,064	38,294	34,615	30,947	33,495	47,864	47,085	10,264	418,172
65%	35,780	26,479	25,438	77,066	37,512	41,126	36,315	32,432	34,394	49,468	48,805	11,508	433,650
70%	37,785	27,659	29,362	81,532	40,980	43,817	37,936	33,936	35,338	51,784	50,833	12,942	448,798
75%	40,064	28,962	35,890	87,070	44,018	46,405	39,860	35,586	36,450	54,207	52,603	14,652	468,727
80%	42,460	30,276	43,826	93,502	47,603	49,495	41,927	37,257	37,815	57,147	54,899	16,640	489,319
85%	45,314	31,939	51,871	100,526	52,202	53,134	43,991	39,030	39,370	60,305	57,568	19,536	515,284
90%	49,472	34,556	63,936	109,043	57,548	58,250	46,480	41,290	41,172	64,826	61,317	23,497	552,654
95%	57,066	38,692	80,397	121,975	65,075	64,183	50,666	44,789	44,205	72,701	68,287	31,625	601,979
97.5%	61,383	42,110	93,950	136,698	72,211	69,608	54,950	48,416	46,713	79,668	77,939	37,486	640,055
99%	69,497	46,234	114,415	152,187	81,016	78,812	59,510	52,597	50,160	90,345	93,660	43,119	697,805

Table 6.28: Forecasted LLH Surplus Sales Statistics For FY 2005 (aMW)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Annual
Average	1,063	760	412	2,652	2,049	1,649	2,216	3,103	3,754	3,477	2,880	566	2,051
Median	1,001	789	25	2,319	1,697	1,553	1,879	2,882	3,281	3,097	2,734	378	2,011
StDev	585	300	773	2,064	1,891	1,474	1,698	2,236	2,151	1,747	865	581	931
1%	86	0	0	0	0	0	0	0	278	1,142	1,477	0	500
2.5%	162	61	0	0	0	0	0	0	544	1,348	1,633	29	558
5%	267	177	0	0	0	0	0	0	804	1,494	1,769	57	630
10%	377	353	0	125	0	70	0	0	1,212	1,649	1,955	100	754
15%	478	450	0	402	0	147	152	584	1,555	1,794	2,086	140	993
20%	575	527	0	644	8	229	450	1,013	1,817	1,930	2,183	170	1,181
25%	658	576	0	995	111	311	772	1,292	2,277	2,051	2,265	203	1,326
30%	742	627	0	1,230	232	417	1,007	1,630	2,459	2,183	2,343	233	1,485
35%	812	671	0	1,444	670	682	1,244	1,799	2,639	2,362	2,418	265	1,624
40%	876	712	0	1,655	1,066	921	1,517	1,956	2,825	2,724	2,501	303	1,734
45%	935	752	0	1,919	1,364	1,286	1,665	2,147	3,056	2,926	2,611	340	1,869
50%	1,001	789	25	2,319	1,697	1,553	1,879	2,882	3,281	3,097	2,734	378	2,011
55%	1,063	820	64	2,653	2,089	1,705	2,229	3,196	3,441	3,244	2,879	426	2,158
60%	1,133	863	109	2,940	2,409	1,873	2,477	3,430	3,606	3,358	3,008	488	2,291
65%	1,203	900	163	3,215	2,785	2,102	2,836	3,945	4,046	3,563	3,112	559	2,394
70%	1,281	934	247	3,552	3,159	2,311	3,396	4,516	4,395	4,020	3,229	627	2,506
75%	1,378	971	430	4,012	3,472	2,495	3,833	4,772	5,635	4,516	3,337	710	2,662
80%	1,477	1,012	668	4,475	3,918	2,719	3,996	5,693	6,307	5,057	3,479	833	2,913
85%	1,591	1,062	854	5,293	4,250	3,041	4,190	6,234	6,634	5,576	3,655	976	3,158
90%	1,733	1,109	1,635	5,776	5,050	3,392	4,542	6,524	6,958	6,394	3,902	1,185	3,307
95%	2,069	1,190	2,372	6,606	5,459	4,155	5,096	6,785	7,594	7,056	4,459	1,933	3,730
97.5%	2,599	1,262	2,921	7,321	6,005	5,447	5,343	6,961	8,192	7,584	4,768	2,283	4,007
99%	3,191	1,393	3,318	7,635	6,190	6,789	6,096	7,092	8,669	7,886	6,164	3,125	4,183

Table 6.29: Forecasted LLH Surplus Sales Revenue Statistics For FY 2005 ($ Thousand)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	11,184	8,698	4,449	22,946	14,090	11,739	14,856	14,041	11,656	22,363	24,803	5,685	166,509
Median	10,480	8,680	300	22,913	13,837	11,113	14,983	15,012	12,148	21,797	24,142	3,919	165,271
StDev	5,884	3,816	7,836	15,044	12,063	9,280	10,280	7,769	3,598	7,119	6,782	5,603	60,408
1%	912	0	0	0	0	0	0	0	2,007	9,029	12,191	0	50,861
2.5%	2,057	689	0	0	0	0	0	0	3,997	10,605	13,721	351	60,418
5%	2,926	1,911	0	0	0	0	0	0	5,521	11,720	14,882	587	70,077
10%	4,248	3,736	0	1,605	0	586	0	0	6,980	13,330	16,618	1,045	80,693
15%	5,229	4,820	0	4,851	0	1,247	1,193	4,311	7,829	14,644	17,678	1,433	96,312
20%	6,230	5,706	0	7,780	53	1,965	3,924	7,238	8,494	16,067	18,814	1,776	112,085
25%	7,050	6,385	0	11,076	1,025	2,657	6,075	9,144	9,258	17,120	19,917	2,085	123,530
30%	7,790	6,876	0	13,882	2,319	3,740	7,981	10,650	10,019	18,152	20,890	2,416	133,816
35%	8,479	7,407	0	16,377	5,551	5,424	9,735	11,785	10,607	19,187	21,728	2,747	143,515
40%	9,070	7,875	0	18,652	8,735	7,416	11,617	12,740	11,239	20,216	22,512	3,074	150,298
45%	9,790	8,309	0	20,799	11,103	9,404	13,107	13,718	11,755	20,947	23,358	3,469	158,012
50%	10,480	8,680	300	22,913	13,837	11,113	14,983	15,012	12,148	21,797	24,142	3,919	165,271
55%	11,135	9,149	823	24,691	16,260	12,752	16,659	16,214	12,495	22,603	25,067	4,465	173,192
60%	11,895	9,547	1,381	26,510	18,343	14,292	18,428	17,086	12,877	23,569	25,921	5,015	182,007
65%	12,662	9,957	2,070	28,758	20,463	15,792	20,161	17,948	13,177	24,509	26,798	5,762	190,273
70%	13,569	10,454	3,166	31,247	22,453	17,222	21,596	18,763	13,573	25,587	27,800	6,452	198,747
75%	14,416	10,988	5,396	33,732	24,112	18,929	22,924	19,621	13,985	26,811	28,986	7,263	208,412
80%	15,670	11,635	7,953	36,131	25,652	20,487	24,408	20,802	14,374	28,530	30,232	8,390	220,132
85%	17,038	12,436	10,906	38,907	27,470	22,190	25,891	22,043	14,870	30,181	31,940	10,124	232,239
90%	18,722	13,607	17,111	42,072	29,702	24,158	27,977	23,239	15,603	32,541	34,015	12,255	247,356
95%	22,164	15,168	23,460	48,017	33,747	27,541	31,439	25,131	16,913	35,441	36,823	17,259	265,278
97.5%	25,069	16,660	27,175	53,021	37,356	30,702	34,230	27,181	18,231	37,389	39,661	21,639	282,459
99%	28,924	18,171	32,533	59,969	41,623	34,179	37,069	29,650	20,115	39,312	43,350	26,847	307,784

Table 6.30: Forecasted Total Surplus Sales Statistics For FY 2005 (aMW)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	1,660	1,119	1,039	3,354	2,297	2,304	2,611	3,658	4,715	4,102	3,396	759	2,590
Median	1,565	1,137	556	3,458	1,982	2,451	2,519	3,775	4,815	4,149	3,335	498	2,628
StDev	785	323	1,130	2,105	2,102	1,742	1,729	1,931	1,914	1,554	923	815	970
1%	390	348	43	0	0	31	0	92	839	1,359	1,740	87	767
2.5%	485	397	154	0	0	53	0	179	1,106	1,573	1,899	104	839
5%	579	537	221	0	0	76	0	269	1,485	1,759	2,056	120	930
10%	743	676	265	220	0	111	32	467	1,981	2,119	2,276	141	1,104
15%	866	792	303	750	0	152	448	1,190	2,370	2,326	2,412	158	1,428
20%	986	866	344	1,128	4	207	961	1,918	2,762	2,516	2,533	178	1,667
25%	1,102	924	377	1,772	51	457	1,286	2,338	3,347	2,690	2,647	218	1,891
30%	1,216	978	409	2,125	136	787	1,543	2,668	3,613	2,902	2,745	267	2,068
35%	1,324	1,021	447	2,317	724	1,274	1,697	3,003	3,931	3,299	2,873	312	2,240
40%	1,409	1,060	483	2,541	1,203	1,690	1,898	3,172	4,175	3,763	3,017	372	2,414
45%	1,472	1,102	519	2,999	1,609	2,159	2,242	3,341	4,557	3,997	3,171	433	2,522
50%	1,565	1,137	556	3,458	1,982	2,451	2,519	3,775	4,815	4,149	3,335	498	2,628
55%	1,643	1,176	610	3,780	2,459	2,643	2,744	4,196	5,042	4,290	3,518	563	2,717
60%	1,727	1,216	668	4,041	2,942	2,923	3,072	4,517	5,246	4,427	3,684	650	2,841
65%	1,828	1,251	736	4,321	3,262	3,166	3,486	4,843	5,570	4,670	3,830	745	3,002
70%	1,940	1,288	852	4,650	3,589	3,409	3,841	4,995	6,109	4,981	3,951	828	3,130
75%	2,078	1,325	1,321	4,965	3,894	3,664	4,151	5,157	6,496	5,246	4,060	952	3,295
80%	2,240	1,371	1,591	5,246	4,242	3,866	4,394	5,482	6,833	5,510	4,190	1,077	3,536
85%	2,415	1,424	1,851	5,861	4,936	4,084	4,623	5,843	7,034	5,991	4,342	1,311	3,744
90%	2,606	1,487	2,827	6,279	5,511	4,377	4,947	6,220	7,196	6,330	4,558	1,589	3,924
95%	3,104	1,592	3,830	6,833	6,101	5,443	5,456	6,436	7,422	6,709	4,985	3,044	4,135
97.5%	3,721	1,722	4,593	7,159	6,305	5,776	5,627	6,569	7,590	6,978	5,185	3,400	4,258
99%	4,369	2,009	4,986	7,463	6,522	6,509	5,759	6,701	7,814	7,416	5,951	4,007	4,363

Table 6.31: Forecasted Total Surplus Sales Revenue Statistics For FY 2005 ($ Thousand)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	43,228	33,069	32,830	85,699	40,355	41,999	43,210	40,408	41,813	68,908	70,885	16,454	558,858
Median	40,694	32,404	19,976	86,703	41,140	44,496	45,971	43,226	44,255	68,847	68,945	11,765	556,130
StDev	18,962	11,326	31,563	50,710	35,173	30,216	25,410	16,708	12,245	19,212	19,437	14,993	178,390
1%	11,389	9,340	1,551	0	0	667	0	2,358	15,595	29,704	36,860	2,448	217,328
2.5%	13,941	11,894	5,502	0	0	1,101	0	4,280	17,153	34,269	40,440	2,735	239,256
5%	16,694	14,952	7,190	0	0	1,600	0	6,587	19,406	37,792	44,028	3,025	268,540
10%	20,636	19,106	9,012	7,802	0	2,261	556	11,177	23,334	43,974	48,274	3,509	310,758
15%	23,929	21,736	10,424	24,589	0	3,228	9,467	21,483	26,574	48,926	51,799	4,060	353,580
20%	26,901	23,775	11,743	37,313	87	5,056	19,454	28,227	29,887	52,530	55,044	4,670	397,688
25%	29,386	25,603	13,037	52,020	1,107	10,013	25,236	31,991	33,237	55,773	57,680	5,428	437,346
30%	31,820	27,228	14,371	60,883	2,876	16,922	29,545	34,816	36,288	59,391	60,349	6,403	469,639
35%	33,919	28,663	15,503	67,518	14,388	25,672	34,180	37,411	39,074	62,278	62,513	7,517	493,068
40%	36,447	29,923	16,953	73,641	25,969	33,297	37,760	39,504	40,906	64,800	64,576	8,651	516,141
45%	38,591	31,058	18,345	80,195	33,621	39,698	41,803	41,304	42,660	66,902	67,019	10,173	536,346
50%	40,694	32,404	19,976	86,703	41,140	44,496	45,971	43,226	44,255	68,847	68,945	11,765	556,130
55%	43,166	33,653	21,748	92,280	46,725	49,237	49,926	44,949	45,428	70,709	71,405	13,323	577,968
60%	45,616	35,037	23,854	99,364	52,462	53,531	53,160	46,492	46,444	73,086	73,541	15,142	601,600
65%	48,518	36,440	27,143	106,128	58,701	57,654	56,236	48,310	47,764	75,242	76,329	17,287	623,050
70%	51,386	38,251	32,494	113,284	63,339	61,741	59,549	50,017	48,816	77,636	79,010	19,413	645,084
75%	54,516	39,650	40,967	120,851	67,993	65,459	62,486	51,963	50,237	80,050	81,587	21,917	673,131
80%	57,948	41,653	51,827	128,109	73,210	69,904	65,761	54,197	51,889	82,942	84,545	25,042	705,164
85%	62,096	43,953	63,319	137,676	79,497	75,058	69,345	56,466	53,455	86,870	88,460	29,672	744,001
90%	68,030	47,763	80,739	149,339	86,584	81,169	74,368	59,086	55,778	92,423	93,175	35,725	791,932
95%	78,754	53,215	102,487	167,173	97,736	88,901	80,974	63,286	59,177	100,889	102,538	49,455	860,515
97.5%	86,121	57,937	121,405	186,219	107,541	97,010	86,549	66,617	62,259	110,142	112,143	58,283	918,268
99%	99,385	63,558	146,602	211,338	120,720	107,950	94,023	71,370	65,404	119,836	127,010	70,691	988,987

Table 6.32: Forecasted HLH Surplus Sales Statistics For FY 2006 (aMW)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Annual
Average	2,121	1,372	1,510	3,559	2,230	2,436	3,187	4,811	5,559	4,479	3,562	760	2,974
Median	1,991	1,371	946	3,831	1,813	2,681	3,295	5,202	6,052	4,798	3,575	372	3,066
StDev	948	364	1,413	2,152	2,168	1,898	1,872	1,925	1,923	1,518	1,006	958	1,019
1%	626	562	70	0	0	0	0	383	1,326	1,326	1,648	39	928
2.5%	687	637	246	0	0	0	0	601	1,542	1,518	1,882	64	1,037
5%	811	766	397	0	0	0	0	1,033	1,994	1,794	2,048	96	1,145
10%	988	907	467	166	0	0	137	1,410	2,615	2,333	2,263	139	1,363
15%	1,164	1,007	531	661	0	1	751	2,084	2,999	2,604	2,416	162	1,664
20%	1,309	1,077	594	1,150	0	133	1,463	3,085	3,551	2,857	2,544	182	2,048
25%	1,448	1,140	651	1,922	0	290	1,831	3,763	4,252	3,096	2,693	198	2,318
30%	1,584	1,196	708	2,372	0	598	2,105	4,211	4,641	3,431	2,821	212	2,496
35%	1,720	1,244	761	2,600	397	1,257	2,372	4,692	5,000	3,906	2,972	228	2,642
40%	1,811	1,284	821	2,875	853	1,839	2,664	4,888	5,346	4,466	3,200	253	2,816
45%	1,908	1,329	880	3,370	1,277	2,352	3,046	5,050	5,778	4,645	3,400	302	2,968
50%	1,991	1,371	946	3,831	1,813	2,681	3,295	5,202	6,052	4,798	3,575	372	3,066
55%	2,091	1,413	1,007	4,201	2,498	2,915	3,543	5,454	6,269	4,945	3,754	467	3,160
60%	2,209	1,457	1,088	4,556	2,936	3,180	3,945	5,805	6,489	5,091	3,962	562	3,280
65%	2,342	1,503	1,196	4,856	3,165	3,483	4,301	6,023	6,666	5,300	4,124	687	3,430
70%	2,448	1,554	1,383	5,141	3,452	3,812	4,532	6,177	6,850	5,520	4,249	803	3,572
75%	2,605	1,602	1,933	5,376	3,771	4,107	4,729	6,307	7,038	5,686	4,401	909	3,745
80%	2,842	1,660	2,262	5,596	4,247	4,309	4,973	6,438	7,240	5,909	4,527	1,073	3,925
85%	3,068	1,716	2,595	5,975	5,077	4,530	5,284	6,593	7,522	6,139	4,671	1,365	4,153
90%	3,303	1,797	3,714	6,311	5,698	4,739	5,689	6,827	7,762	6,324	4,855	1,668	4,354
95%	3,853	1,931	5,029	6,592	6,227	5,329	5,970	7,161	8,031	6,607	5,147	3,678	4,516
97.5%	4,616	2,117	5,909	6,902	6,413	6,003	6,146	7,349	8,457	6,799	5,388	4,032	4,615
99%	5,272	2,463	6,272	7,178	6,531	6,267	6,282	7,575	8,727	6,959	5,543	4,434	4,710

Table 6.33: Forecasted HLH Surplus Sales Revenue Statistics For FY 2006 ($ Thousand)													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	30,089	21,951	26,531	54,835	24,172	27,068	34,500	28,267	32,445	48,390	47,809	9,186	385,243
Median	28,886	21,317	17,620	55,680	22,615	28,647	37,550	27,548	34,251	45,747	44,413	5,351	384,095
StDev	12,701	7,068	22,816	32,060	22,710	21,081	18,529	12,317	12,246	18,506	18,206	9,281	114,808
1%	8,944	8,567	1,354	0	0	0	0	6,168	9,451	16,932	22,740	620	163,170
2.5%	10,561	9,974	4,565	0	0	0	0	8,089	10,578	20,841	25,098	1,025	175,727
5%	12,405	11,367	6,674	0	0	0	0	10,454	11,932	24,750	28,038	1,509	195,013
10%	14,932	13,569	8,403	3,405	0	0	2,203	13,035	14,425	29,890	31,077	2,023	232,241
15%	16,954	14,945	9,665	13,027	0	19	11,014	15,062	16,927	33,183	33,716	2,374	262,827
20%	18,670	16,005	10,684	23,219	0	1,885	18,299	16,963	19,959	35,636	35,377	2,684	285,107
25%	20,712	16,910	11,866	35,189	0	4,024	23,253	18,453	22,911	37,673	37,074	2,987	306,489
30%	22,309	17,912	13,011	41,853	0	7,926	26,685	20,031	25,721	39,326	38,584	3,262	325,226
35%	24,030	18,893	14,022	46,040	5,281	15,210	29,667	21,610	28,259	41,063	40,031	3,570	341,565
40%	25,725	19,717	15,149	49,552	11,422	21,330	32,724	23,449	30,420	42,452	41,526	3,990	356,524
45%	27,253	20,496	16,270	52,690	16,620	25,654	35,010	25,446	32,697	44,087	42,910	4,530	368,981
50%	28,886	21,317	17,620	55,680	22,615	28,647	37,550	27,548	34,251	45,747	44,413	5,351	384,095
55%	30,364	22,197	19,233	59,448	28,206	31,859	39,548	29,346	35,679	47,475	46,083	6,448	396,956
60%	31,851	23,030	21,215	63,376	32,127	34,843	41,421	31,097	37,045	49,553	47,844	7,759	412,653
65%	33,275	23,935	23,861	68,006	35,807	37,680	43,177	33,342	38,338	51,549	49,550	8,974	426,786
70%	35,214	24,924	27,373	72,542	38,801	40,345	45,213	35,317	39,647	54,067	51,874	10,512	442,453
75%	37,244	25,981	33,660	77,193	41,594	43,196	47,321	36,956	40,779	56,658	53,955	12,088	458,138
80%	40,149	27,366	40,738	81,785	45,345	45,852	49,757	38,827	42,354	59,823	56,670	14,369	476,149
85%	43,057	28,910	48,693	87,923	49,693	49,766	52,415	41,409	44,370	63,546	60,578	17,305	500,899
90%	47,266	31,066	58,578	94,588	54,106	54,144	56,250	44,610	47,003	69,182	66,141	21,257	530,149
95%	53,731	34,512	77,653	107,189	62,086	60,401	61,645	49,207	50,921	77,741	76,659	29,828	578,482
97.5%	58,380	37,919	90,991	115,511	71,419	66,804	66,557	53,422	54,376	86,310	90,159	36,725	622,150
99%	67,202	42,744	105,986	124,760	79,386	74,828	72,731	59,116	59,035	99,062	117,809	43,075	681,941

Table 6.34: Forecasted LLH Surplus Sales Statistics For FY 2006 (aMW)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Annual
Average	945	645	351	2,179	1,694	1,259	2,311	3,836	3,776	3,209	2,514	287	1,921
Median	885	665	0	1,777	1,187	1,005	2,054	3,692	3,301	2,817	2,367	57	1,888
StDev	593	295	740	1,993	1,758	1,377	1,749	2,362	2,184	1,776	876	522	923
1%	0	0	0	0	0	0	0	0	198	792	1,034	0	376
2.5%	0	0	0	0	0	0	0	2	472	978	1,264	0	450
5%	92	78	0	0	0	0	0	201	757	1,147	1,409	0	518
10%	237	237	0	0	0	0	0	607	1,153	1,352	1,573	0	665
15%	352	334	0	0	0	0	99	1,169	1,519	1,515	1,691	0	859
20%	455	400	0	99	0	0	413	1,670	1,845	1,643	1,805	0	1,043
25%	538	452	0	400	0	6	818	2,043	2,288	1,779	1,883	0	1,223
30%	617	508	0	673	0	102	1,076	2,359	2,504	1,925	1,972	0	1,360
35%	691	547	0	882	148	186	1,321	2,614	2,680	2,119	2,055	0	1,482
40%	757	588	0	1,117	548	415	1,615	2,796	2,856	2,466	2,136	0	1,588
45%	821	626	0	1,447	829	750	1,814	2,996	3,073	2,653	2,246	27	1,718
50%	885	665	0	1,777	1,187	1,005	2,054	3,692	3,301	2,817	2,367	57	1,888
55%	944	703	0	2,091	1,589	1,178	2,381	4,010	3,459	2,947	2,506	90	2,027
60%	1,018	736	0	2,373	1,929	1,348	2,647	4,294	3,671	3,068	2,647	139	2,146
65%	1,093	770	36	2,641	2,279	1,591	3,004	4,682	4,056	3,299	2,757	190	2,266
70%	1,168	807	137	2,987	2,627	1,812	3,522	5,407	4,451	3,735	2,871	266	2,379
75%	1,256	849	290	3,517	3,000	2,043	3,934	5,710	5,632	4,238	2,991	346	2,522
80%	1,363	889	499	3,954	3,437	2,253	4,128	6,607	6,330	4,821	3,124	443	2,763
85%	1,492	936	707	4,741	3,780	2,589	4,373	6,991	6,670	5,362	3,310	609	3,009
90%	1,638	1,007	1,457	5,272	4,570	2,927	4,695	7,302	7,051	6,201	3,583	833	3,167
95%	1,925	1,094	2,276	6,128	5,050	3,619	5,225	7,614	7,732	6,870	4,098	1,559	3,546
97.5%	2,514	1,183	2,802	6,759	5,494	4,977	5,524	7,776	8,218	7,395	4,430	1,885	3,892
99%	3,079	1,316	3,201	7,102	5,724	6,399	6,210	7,917	8,716	7,629	5,758	2,713	4,031

Table 6.35: Forecasted LLH Surplus Sales Revenue Statistics For FY 2006 ($ Thousand)													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	9,183	6,628	3,498	17,805	11,782	8,967	16,560	16,444	11,460	20,846	22,718	2,847	148,738
Median	8,645	6,633	0	18,721	9,797	7,622	16,713	17,116	11,812	20,277	21,734	574	148,078
StDev	5,598	3,221	7,008	13,488	11,441	8,837	11,465	7,517	3,836	7,471	7,380	5,065	56,491
1%	0	0	0	0	0	0	0	0	1,494	7,164	9,671	0	42,047
2.5%	0	0	0	0	0	0	0	15	3,657	8,270	11,205	0	48,291
5%	955	805	0	0	0	0	0	1,727	5,467	9,684	12,485	0	55,594
10%	2,467	2,378	0	0	0	0	0	4,703	6,837	11,410	14,420	0	69,123
15%	3,503	3,329	0	0	0	0	945	8,357	7,448	12,745	15,584	0	83,352
20%	4,527	4,021	0	1,149	0	0	3,743	10,935	8,022	13,980	16,574	0	98,175
25%	5,294	4,486	0	5,042	0	51	6,791	12,361	8,529	15,105	17,585	0	109,895
30%	6,005	4,981	0	8,192	0	848	9,376	13,768	9,035	16,438	18,397	0	119,062
35%	6,608	5,425	0	10,280	1,391	1,612	11,196	14,764	9,701	17,375	19,174	0	126,230
40%	7,240	5,840	0	12,833	4,755	3,715	13,187	15,485	10,357	18,346	20,020	0	133,700
45%	7,938	6,226	0	15,764	6,889	5,968	14,951	16,384	11,131	19,345	20,951	268	140,734
50%	8,645	6,633	0	18,721	9,797	7,622	16,713	17,116	11,812	20,277	21,734	574	148,078
55%	9,302	7,037	0	20,979	12,548	9,006	18,711	17,741	12,538	21,271	22,635	948	154,795
60%	9,940	7,447	0	22,769	15,238	10,370	20,303	18,610	12,969	22,174	23,586	1,442	162,162
65%	10,599	7,824	407	24,606	17,532	11,933	22,241	19,372	13,406	23,290	24,511	1,968	170,473
70%	11,409	8,238	1,601	26,258	19,790	13,537	23,876	20,257	13,818	24,475	25,420	2,636	178,031
75%	12,183	8,672	3,395	28,124	21,596	15,059	25,587	21,118	14,263	25,892	26,591	3,471	186,824
80%	13,258	9,189	5,681	30,026	23,143	17,214	27,382	22,313	14,745	27,416	28,239	4,645	197,714
85%	14,548	9,859	8,219	32,160	24,864	19,115	29,358	23,488	15,325	29,081	29,949	6,163	208,617
90%	16,244	10,568	14,555	34,750	27,152	21,512	31,548	25,177	15,973	31,442	32,335	8,333	225,814
95%	19,499	11,999	21,765	39,146	30,581	24,944	34,847	28,314	17,009	34,218	36,419	13,033	243,503
97.5%	22,428	13,235	25,166	43,890	34,026	28,626	37,093	30,772	18,002	36,049	39,842	18,880	259,968
99%	26,540	14,444	28,306	48,554	39,559	32,641	40,319	33,576	19,065	37,909	44,458	25,549	280,788

Table 6.36: Forecasted Total Surplus Sales Statistics For FY 2006 (aMW)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	1,617	1,060	1,013	2,968	2,000	1,932	2,812	4,393	4,795	3,935	3,113	557	2,523
Median	1,517	1,075	544	2,997	1,515	1,983	2,790	4,609	4,935	3,967	3,056	219	2,565
StDev	794	326	1,117	2,043	1,978	1,638	1,802	2,050	1,948	1,575	934	767	967
1%	360	325	40	0	0	0	0	219	857	1,104	1,394	48	705
2.5%	403	371	140	0	0	0	0	396	1,121	1,323	1,625	61	794
5%	511	484	227	0	0	0	0	669	1,444	1,542	1,782	72	875
10%	673	625	267	95	0	19	83	1,046	1,996	1,922	1,982	89	1,066
15%	809	726	303	380	0	52	475	1,694	2,357	2,147	2,112	100	1,334
20%	938	797	339	710	0	103	1,036	2,487	2,806	2,344	2,232	109	1,611
25%	1,056	857	372	1,294	0	166	1,422	3,045	3,414	2,526	2,362	117	1,851
30%	1,169	906	404	1,641	0	356	1,723	3,455	3,715	2,766	2,459	124	2,011
35%	1,276	949	435	1,874	287	769	1,921	3,771	4,008	3,130	2,584	133	2,152
40%	1,361	990	470	2,122	750	1,197	2,142	3,968	4,251	3,628	2,722	147	2,308
45%	1,439	1,028	505	2,603	1,165	1,709	2,507	4,183	4,625	3,810	2,901	174	2,443
50%	1,517	1,075	544	2,997	1,515	1,983	2,790	4,609	4,935	3,967	3,056	219	2,565
55%	1,604	1,112	583	3,321	2,075	2,158	3,016	5,034	5,141	4,104	3,214	295	2,664
60%	1,702	1,152	630	3,623	2,521	2,387	3,366	5,350	5,338	4,262	3,401	370	2,788
65%	1,805	1,189	707	3,875	2,821	2,667	3,771	5,620	5,662	4,503	3,555	469	2,938
70%	1,902	1,229	839	4,228	3,142	2,958	4,114	5,830	6,165	4,809	3,666	564	3,062
75%	2,020	1,275	1,207	4,535	3,471	3,209	4,369	6,022	6,650	5,075	3,793	669	3,227
80%	2,194	1,318	1,527	4,835	3,844	3,448	4,634	6,334	6,953	5,372	3,922	806	3,453
85%	2,389	1,371	1,770	5,435	4,539	3,688	4,873	6,630	7,149	5,865	4,077	1,045	3,649
90%	2,590	1,443	2,797	5,890	5,101	3,941	5,231	6,976	7,300	6,178	4,292	1,319	3,861
95%	3,025	1,560	3,837	6,404	5,745	4,935	5,688	7,245	7,520	6,594	4,679	2,765	4,062
97.5%	3,717	1,673	4,578	6,736	5,908	5,344	5,893	7,395	7,731	6,840	4,925	3,112	4,195
99%	4,332	1,945	4,956	7,032	6,108	6,150	6,022	7,493	7,924	7,198	5,620	3,696	4,310

Table 6.37: Forecasted Total Surplus Sales Revenue Statistics For FY 2006 ($ Thousand)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	39,272	28,580	30,029	72,640	35,954	36,036	51,060	44,711	43,905	69,235	70,527	12,032	533,981
Median	37,645	28,013	17,785	76,157	32,645	37,307	55,178	46,090	46,288	68,599	67,561	5,583	534,824
StDev	18,160	9,994	29,479	44,221	33,744	29,148	29,241	17,085	15,260	22,079	22,105	14,145	166,358
1%	9,403	8,834	1,354	0	0	0	0	6,221	16,124	26,452	33,957	1,349	209,935
2.5%	11,144	10,652	4,565	0	0	0	0	8,867	17,237	31,289	37,367	1,624	228,860
5%	13,703	13,048	6,674	0	0	0	0	15,690	19,033	35,932	41,562	1,899	259,144
10%	17,503	16,437	8,403	3,405	0	426	2,223	21,173	21,763	42,563	46,750	2,288	302,788
15%	20,660	18,490	9,665	13,148	0	1,077	12,236	25,629	24,337	48,135	50,418	2,562	348,738
20%	23,215	20,187	10,693	24,509	0	2,154	23,017	29,703	27,562	52,249	53,335	2,838	388,224
25%	25,926	21,722	11,904	42,655	0	4,055	30,861	33,310	31,348	56,068	55,930	3,094	419,216
30%	28,388	23,137	13,027	51,824	0	7,986	36,549	36,460	34,792	59,465	58,538	3,326	449,857
35%	30,601	24,203	14,053	58,546	6,398	16,346	42,395	39,120	37,991	61,918	61,000	3,660	473,166
40%	32,860	25,581	15,218	64,542	16,942	25,609	46,528	41,522	41,037	64,377	63,019	4,050	494,139
45%	35,500	26,795	16,343	70,780	24,573	32,400	51,101	43,598	43,766	66,443	65,142	4,683	514,914
50%	37,645	28,013	17,785	76,157	32,645	37,307	55,178	46,090	46,288	68,599	67,561	5,583	534,824
55%	39,585	29,205	19,496	80,977	41,006	42,186	58,685	48,072	48,221	70,620	70,069	7,084	552,861
60%	41,629	30,509	21,560	86,915	48,030	46,345	61,995	49,893	49,959	72,885	72,374	8,755	573,222
65%	43,721	31,616	24,525	91,958	53,761	49,848	65,543	51,905	51,715	75,468	75,427	10,886	596,645
70%	46,555	33,002	28,921	97,871	58,636	54,484	68,890	53,962	53,152	77,885	77,972	13,188	616,054
75%	49,541	34,465	37,253	104,027	63,644	58,640	72,567	56,343	54,794	80,833	81,176	15,621	641,607
80%	53,477	36,383	46,518	110,283	68,342	63,080	76,564	58,749	56,924	83,987	85,043	18,923	672,322
85%	57,518	38,513	57,172	117,941	73,884	67,908	80,722	61,488	59,238	88,243	89,690	23,447	702,852
90%	63,393	41,019	73,224	127,006	80,113	74,241	86,540	65,480	62,300	94,386	96,185	29,720	746,152
95%	73,323	46,141	98,842	143,612	91,339	83,014	94,186	71,277	66,625	103,634	107,059	42,674	813,788
97.5%	79,257	50,756	116,967	155,240	103,280	91,746	102,149	77,022	70,973	113,414	122,537	57,564	872,675
99%	93,424	56,771	132,369	169,702	117,303	103,590	111,415	84,897	75,795	123,749	141,601	67,310	946,302

Table 6.38: Forecasted HLH Power Purchase Statistics For FY 2004 (aMW)													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Annual
Average	0	0	5	26	157	17	28	0	0	0	0	0	19
Median	0	0	0	0	0	0	0	0	0	0	0	0	0
StDev	0	0	39	108	284	68	122	0	0	0	0	2	36
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	0	0	0	0	0	0	0	0	0	0	0	0	0
20%	0	0	0	0	0	0	0	0	0	0	0	0	0
25%	0	0	0	0	0	0	0	0	0	0	0	0	0
30%	0	0	0	0	0	0	0	0	0	0	0	0	0
35%	0	0	0	0	0	0	0	0	0	0	0	0	0
40%	0	0	0	0	0	0	0	0	0	0	0	0	0
45%	0	0	0	0	0	0	0	0	0	0	0	0	0
50%	0	0	0	0	0	0	0	0	0	0	0	0	0
55%	0	0	0	0	0	0	0	0	0	0	0	0	0
60%	0	0	0	0	0	0	0	0	0	0	0	0	0
65%	0	0	0	0	0	0	0	0	0	0	0	0	0
70%	0	0	0	0	82	0	0	0	0	0	0	0	12
75%	0	0	0	0	266	0	0	0	0	0	0	0	25
80%	0	0	0	0	364	0	0	0	0	0	0	0	35
85%	0	0	0	0	425	0	0	0	0	0	0	0	49
90%	0	0	0	0	615	28	0	0	0	0	0	0	72
95%	0	0	0	190	824	145	166	0	0	0	0	0	102
97.5%	0	0	35	411	967	210	435	0	0	0	0	0	127
99%	0	0	190	561	1,122	322	705	0	0	0	0	0	159

Table 6.39: Forecasted HLH Power Purchase Expense Statistics For FY 2004 ($ Thousand)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	0	0	102	616	2,812	276	451	0	0	0	0	2	4,260
Median	0	0	0	0	0	0	0	0	0	0	0	0	0
StDev	0	0	791	2,656	5,390	1,159	2,000	10	0	0	0	33	8,442
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	0	0	0	0	0	0	0	0	0	0	0	0	0
20%	0	0	0	0	0	0	0	0	0	0	0	0	0
25%	0	0	0	0	0	0	0	0	0	0	0	0	0
30%	0	0	0	0	0	0	0	0	0	0	0	0	0
35%	0	0	0	0	0	0	0	0	0	0	0	0	0
40%	0	0	0	0	0	0	0	0	0	0	0	0	0
45%	0	0	0	0	0	0	0	0	0	0	0	0	0
50%	0	0	0	0	0	0	0	0	0	0	0	0	0
55%	0	0	0	0	0	0	0	0	0	0	0	0	0
60%	0	0	0	0	0	0	0	0	0	0	0	0	0
65%	0	0	0	0	0	0	0	0	0	0	0	0	0
70%	0	0	0	0	1,297	0	0	0	0	0	0	0	2,285
75%	0	0	0	0	4,154	0	0	0	0	0	0	0	4,826
80%	0	0	0	0	6,025	0	0	0	0	0	0	0	7,645
85%	0	0	0	0	7,962	0	0	0	0	0	0	0	11,207
90%	0	0	0	0	10,397	447	0	0	0	0	0	0	15,738
95%	0	0	0	4,462	14,333	2,158	2,782	0	0	0	0	0	23,962
97.5%	0	0	602	9,055	18,611	3,192	7,159	0	0	0	0	0	29,864
99%	0	0	3,795	14,680	22,654	4,790	11,408	0	0	0	0	0	36,683

Table 6.40: Forecasted LLH Power Purchase Statistics For FY 2004 (aMW)													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Annual
Average	1	35	388	21	29	10	8	2	0	0	0	1	42
Median	0	0	401	0	0	0	0	0	0	0	0	0	38
StDev	9	55	210	69	98	44	49	20	3	0	0	7	25
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	9
15%	0	0	207	0	0	0	0	0	0	0	0	0	20
20%	0	0	274	0	0	0	0	0	0	0	0	0	24
25%	0	0	300	0	0	0	0	0	0	0	0	0	27
30%	0	0	316	0	0	0	0	0	0	0	0	0	29
35%	0	0	337	0	0	0	0	0	0	0	0	0	31
40%	0	0	355	0	0	0	0	0	0	0	0	0	33
45%	0	0	378	0	0	0	0	0	0	0	0	0	36
50%	0	0	401	0	0	0	0	0	0	0	0	0	38
55%	0	8	420	0	0	0	0	0	0	0	0	0	41
60%	0	18	436	0	0	0	0	0	0	0	0	0	44
65%	0	30	453	0	0	0	0	0	0	0	0	0	47
70%	0	42	471	0	0	0	0	0	0	0	0	0	51
75%	0	57	489	0	0	0	0	0	0	0	0	0	56
80%	0	72	515	0	0	0	0	0	0	0	0	0	61
85%	0	91	570	0	0	0	0	0	0	0	0	0	66
90%	0	121	651	70	99	0	0	0	0	0	0	0	73
95%	0	157	735	175	219	85	0	0	0	0	0	0	86
97.5%	0	187	829	210	362	174	110	0	0	0	0	0	100
99%	51	214	912	311	528	248	250	37	0	0	0	15	118

Table 6.41: Forecasted LLH Power Purchase Expense Statistics For FY 2004 ($ Thousand)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	14	433	4,996	305	351	103	85	17	1	0	0	7	6,312
Median	0	0	4,860	0	0	0	0	0	0	0	0	0	5,627
StDev	115	693	3,065	1,069	1,240	485	542	191	28	0	0	79	4,283
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	1,183
15%	0	0	2,110	0	0	0	0	0	0	0	0	0	2,499
20%	0	0	2,885	0	0	0	0	0	0	0	0	0	3,096
25%	0	0	3,308	0	0	0	0	0	0	0	0	0	3,617
30%	0	0	3,662	0	0	0	0	0	0	0	0	0	3,980
35%	0	0	3,949	0	0	0	0	0	0	0	0	0	4,393
40%	0	0	4,284	0	0	0	0	0	0	0	0	0	4,808
45%	0	0	4,553	0	0	0	0	0	0	0	0	0	5,215
50%	0	0	4,860	0	0	0	0	0	0	0	0	0	5,627
55%	0	84	5,177	0	0	0	0	0	0	0	0	0	6,069
60%	0	207	5,450	0	0	0	0	0	0	0	0	0	6,490
65%	0	347	5,792	0	0	0	0	0	0	0	0	0	7,097
70%	0	504	6,184	0	0	0	0	0	0	0	0	0	7,754
75%	0	677	6,642	0	0	0	0	0	0	0	0	0	8,364
80%	0	878	7,159	0	0	0	0	0	0	0	0	0	9,227
85%	0	1,103	7,844	0	0	0	0	0	0	0	0	0	10,291
90%	0	1,421	8,827	924	1,018	0	0	0	0	0	0	0	11,832
95%	0	1,908	10,357	2,413	2,415	701	0	0	0	0	0	0	14,322
97.5%	0	2,400	11,979	3,347	4,190	1,722	1,225	0	0	0	0	0	16,381
99%	615	2,887	13,351	4,870	6,479	2,624	2,960	299	0	0	0	165	19,779

Table 6.42: Forecasted Total Power Purchase Statistics For FY 2004 (aMW)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	0	15	169	24	102	14	19	1	0	0	0	0	29
Median	0	0	172	0	0	0	0	0	0	0	0	0	18
StDev	4	23	100	80	196	44	84	8	1	0	0	3	28
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	4
15%	0	0	89	0	0	0	0	0	0	0	0	0	9
20%	0	0	117	0	0	0	0	0	0	0	0	0	10
25%	0	0	128	0	0	0	0	0	0	0	0	0	12
30%	0	0	135	0	0	0	0	0	0	0	0	0	13
35%	0	0	144	0	0	0	0	0	0	0	0	0	14
40%	0	0	152	0	0	0	0	0	0	0	0	0	16
45%	0	0	162	0	0	0	0	0	0	0	0	0	17
50%	0	0	172	0	0	0	0	0	0	0	0	0	18
55%	0	3	180	0	0	0	0	0	0	0	0	0	20
60%	0	8	187	0	0	0	0	0	0	0	0	0	23
65%	0	13	194	0	0	0	0	0	0	0	0	0	27
70%	0	18	202	0	53	0	0	0	0	0	0	0	31
75%	0	24	210	0	170	0	0	0	0	0	0	0	35
80%	0	31	221	0	212	0	0	0	0	0	0	0	42
85%	0	39	245	41	246	17	0	0	0	0	0	0	53
90%	0	52	281	73	379	64	0	0	0	0	0	0	69
95%	0	67	324	134	559	98	97	0	0	0	0	0	92
97.5%	0	80	375	251	705	124	292	0	0	0	0	0	111
99%	22	92	466	410	860	184	483	16	0	0	0	10	137

Table 6.43: Forecasted Total Power Purchase Expense Statistics For FY 2004 ($ Thousand)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	14	433	5,097	921	3,163	379	536	18	1	0	0	9	10,572
Median	0	0	4,860	0	0	0	0	0	0	0	0	0	6,449
StDev	115	693	3,406	3,316	6,394	1,299	2,380	195	28	0	0	85	11,579
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	1,183
15%	0	0	2,110	0	0	0	0	0	0	0	0	0	2,531
20%	0	0	2,885	0	0	0	0	0	0	0	0	0	3,239
25%	0	0	3,308	0	0	0	0	0	0	0	0	0	3,777
30%	0	0	3,662	0	0	0	0	0	0	0	0	0	4,251
35%	0	0	3,949	0	0	0	0	0	0	0	0	0	4,774
40%	0	0	4,284	0	0	0	0	0	0	0	0	0	5,276
45%	0	0	4,553	0	0	0	0	0	0	0	0	0	5,867
50%	0	0	4,860	0	0	0	0	0	0	0	0	0	6,449
55%	0	84	5,177	0	0	0	0	0	0	0	0	0	7,175
60%	0	207	5,450	0	0	0	0	0	0	0	0	0	8,124
65%	0	347	5,792	0	0	0	0	0	0	0	0	0	9,270
70%	0	504	6,191	0	1,342	0	0	0	0	0	0	0	10,732
75%	0	677	6,658	0	4,390	0	0	0	0	0	0	0	12,972
80%	0	878	7,187	0	6,153	0	0	0	0	0	0	0	15,621
85%	0	1,103	7,870	1,396	8,237	458	0	0	0	0	0	0	20,218
90%	0	1,421	8,916	2,440	11,328	1,373	0	0	0	0	0	0	25,490
95%	0	1,908	10,788	5,171	16,614	2,594	2,807	0	0	0	0	0	36,078
97.5%	0	2,400	12,657	9,957	22,604	3,332	8,166	0	0	0	0	0	44,459
99%	615	2,887	15,415	17,189	29,002	5,003	13,116	299	0	0	0	308	54,013

Table 6.44: Forecasted HLH Power Purchase Statistics For FY 2005 (aMW)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Annual
Average	0	0	1	25	151	8	34	0	0	0	0	0	17
Median	0	0	0	0	0	0	0	0	0	0	0	0	0
StDev	0	0	16	109	279	32	132	3	0	0	0	1	35
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	0	0	0	0	0	0	0	0	0	0	0	0	0
20%	0	0	0	0	0	0	0	0	0	0	0	0	0
25%	0	0	0	0	0	0	0	0	0	0	0	0	0
30%	0	0	0	0	0	0	0	0	0	0	0	0	0
35%	0	0	0	0	0	0	0	0	0	0	0	0	0
40%	0	0	0	0	0	0	0	0	0	0	0	0	0
45%	0	0	0	0	0	0	0	0	0	0	0	0	0
50%	0	0	0	0	0	0	0	0	0	0	0	0	0
55%	0	0	0	0	0	0	0	0	0	0	0	0	0
60%	0	0	0	0	0	0	0	0	0	0	0	0	0
65%	0	0	0	0	0	0	0	0	0	0	0	0	0
70%	0	0	0	0	18	0	0	0	0	0	0	0	4
75%	0	0	0	0	229	0	0	0	0	0	0	0	18
80%	0	0	0	0	345	0	0	0	0	0	0	0	29
85%	0	0	0	0	438	0	0	0	0	0	0	0	48
90%	0	0	0	0	607	0	0	0	0	0	0	0	72
95%	0	0	0	209	795	70	295	0	0	0	0	0	101
97.5%	0	0	0	409	923	122	480	0	0	0	0	0	122
99%	0	0	0	568	1,103	164	745	0	0	0	0	0	147

Table 6.45: Forecasted HLH Power Purchase Expense Statistics For FY 2005 ($ Thousand)													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	0	0	24	558	2,305	113	499	3	0	0	0	2	3,504
Median	0	0	0	0	0	0	0	0	0	0	0	0	0
StDev	0	0	371	2,506	4,503	483	1,977	76	0	0	0	35	7,367
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	0	0	0	0	0	0	0	0	0	0	0	0	0
20%	0	0	0	0	0	0	0	0	0	0	0	0	0
25%	0	0	0	0	0	0	0	0	0	0	0	0	0
30%	0	0	0	0	0	0	0	0	0	0	0	0	0
35%	0	0	0	0	0	0	0	0	0	0	0	0	0
40%	0	0	0	0	0	0	0	0	0	0	0	0	0
45%	0	0	0	0	0	0	0	0	0	0	0	0	0
50%	0	0	0	0	0	0	0	0	0	0	0	0	0
55%	0	0	0	0	0	0	0	0	0	0	0	0	0
60%	0	0	0	0	0	0	0	0	0	0	0	0	0
65%	0	0	0	0	0	0	0	0	0	0	0	0	0
70%	0	0	0	0	318	0	0	0	0	0	0	0	784
75%	0	0	0	0	3,148	0	0	0	0	0	0	0	3,352
80%	0	0	0	0	4,750	0	0	0	0	0	0	0	5,443
85%	0	0	0	0	6,389	0	0	0	0	0	0	0	8,896
90%	0	0	0	0	8,835	0	0	0	0	0	0	0	13,877
95%	0	0	0	4,100	12,398	950	4,222	0	0	0	0	0	20,454
97.5%	0	0	0	8,708	15,654	1,694	6,779	0	0	0	0	0	25,133
99%	0	0	0	12,881	19,040	2,458	10,631	0	0	0	0	0	32,943

Table 6.46: Forecasted LLH Power Purchase Statistics For FY 2005 (aMW)													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Annual
Average	0	1	102	17	40	12	32	33	0	0	0	0	20
Median	0	0	0	0	0	0	0	0	0	0	0	0	7
StDev	3	9	155	78	115	53	99	111	6	0	0	5	30
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	0	0	0	0	0	0	0	0	0	0	0	0	0
20%	0	0	0	0	0	0	0	0	0	0	0	0	0
25%	0	0	0	0	0	0	0	0	0	0	0	0	0
30%	0	0	0	0	0	0	0	0	0	0	0	0	0
35%	0	0	0	0	0	0	0	0	0	0	0	0	0
40%	0	0	0	0	0	0	0	0	0	0	0	0	0
45%	0	0	0	0	0	0	0	0	0	0	0	0	3
50%	0	0	0	0	0	0	0	0	0	0	0	0	7
55%	0	0	14	0	0	0	0	0	0	0	0	0	10
60%	0	0	54	0	0	0	0	0	0	0	0	0	14
65%	0	0	91	0	0	0	0	0	0	0	0	0	19
70%	0	0	128	0	0	0	0	0	0	0	0	0	22
75%	0	0	175	0	0	0	0	0	0	0	0	0	27
80%	0	0	222	0	0	0	0	0	0	0	0	0	33
85%	0	0	274	0	67	0	0	0	0	0	0	0	42
90%	0	0	334	0	164	0	131	62	0	0	0	0	58
95%	0	0	419	116	269	53	279	319	0	0	0	0	86
97.5%	0	0	495	250	387	242	368	441	0	0	0	0	111
99%	0	35	604	421	565	273	481	588	0	0	0	3	135

Table 6.47: Forecasted LLH Power Purchase Expense Statistics For FY 2005 ($ Thousand)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	2	10	1,410	240	412	107	302	285	2	0	0	5	2,774
Median	0	0	0	0	0	0	0	0	0	0	0	0	966
StDev	36	100	2,259	1,167	1,248	516	972	984	45	0	0	60	4,346
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	0	0	0	0	0	0	0	0	0	0	0	0	0
20%	0	0	0	0	0	0	0	0	0	0	0	0	0
25%	0	0	0	0	0	0	0	0	0	0	0	0	0
30%	0	0	0	0	0	0	0	0	0	0	0	0	0
35%	0	0	0	0	0	0	0	0	0	0	0	0	0
40%	0	0	0	0	0	0	0	0	0	0	0	0	0
45%	0	0	0	0	0	0	0	0	0	0	0	0	461
50%	0	0	0	0	0	0	0	0	0	0	0	0	966
55%	0	0	177	0	0	0	0	0	0	0	0	0	1,418
60%	0	0	682	0	0	0	0	0	0	0	0	0	1,960
65%	0	0	1,157	0	0	0	0	0	0	0	0	0	2,495
70%	0	0	1,677	0	0	0	0	0	0	0	0	0	3,160
75%	0	0	2,294	0	0	0	0	0	0	0	0	0	3,951
80%	0	0	2,894	0	0	0	0	0	0	0	0	0	4,849
85%	0	0	3,749	0	615	0	0	0	0	0	0	0	5,912
90%	0	0	4,647	0	1,417	0	1,141	467	0	0	0	0	7,921
95%	0	0	5,929	1,389	2,827	445	2,566	2,599	0	0	0	0	11,824
97.5%	0	0	7,448	3,310	4,141	1,983	3,535	3,765	0	0	0	0	15,108
99%	0	374	9,580	6,122	6,357	2,869	4,779	5,014	0	0	0	36	19,980

Table 6.48: Forecasted Total Power Purchase Statistics For FY 2005 (aMW)													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	0	0	44	22	104	9	33	14	0	0	0	0	18
Median	0	0	0	0	0	0	0	0	0	0	0	0	4
StDev	1	4	70	93	200	29	108	48	2	0	0	2	31
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	0	0	0	0	0	0	0	0	0	0	0	0	0
20%	0	0	0	0	0	0	0	0	0	0	0	0	0
25%	0	0	0	0	0	0	0	0	0	0	0	0	0
30%	0	0	0	0	0	0	0	0	0	0	0	0	0
35%	0	0	0	0	0	0	0	0	0	0	0	0	0
40%	0	0	0	0	0	0	0	0	0	0	0	0	1
45%	0	0	0	0	0	0	0	0	0	0	0	0	3
50%	0	0	0	0	0	0	0	0	0	0	0	0	4
55%	0	0	6	0	0	0	0	0	0	0	0	0	7
60%	0	0	23	0	0	0	0	0	0	0	0	0	9
65%	0	0	39	0	0	0	0	0	0	0	0	0	11
70%	0	0	55	0	13	0	0	0	0	0	0	0	14
75%	0	0	75	0	170	0	0	0	0	0	0	0	19
80%	0	0	95	0	215	0	0	0	0	0	0	0	28
85%	0	0	118	0	263	0	0	0	0	0	0	0	43
90%	0	0	143	0	382	37	89	27	0	0	0	0	65
95%	0	0	179	147	564	85	295	137	0	0	0	0	91
97.5%	0	0	212	323	684	108	404	189	0	0	0	0	112
99%	0	15	272	491	865	131	528	253	0	0	0	8	137

Table 6.49: Forecasted Total Power Purchase Expense Statistics For FY 2005 ($ Thousand)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	2	10	1,434	799	2,717	220	801	288	2	0	0	6	6,278
Median	0	0	0	0	0	0	0	0	0	0	0	0	1,513
StDev	36	100	2,406	3,573	5,539	693	2,724	1,001	45	0	0	69	11,112
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	0	0	0	0	0	0	0	0	0	0	0	0	0
20%	0	0	0	0	0	0	0	0	0	0	0	0	0
25%	0	0	0	0	0	0	0	0	0	0	0	0	0
30%	0	0	0	0	0	0	0	0	0	0	0	0	0
35%	0	0	0	0	0	0	0	0	0	0	0	0	0
40%	0	0	0	0	0	0	0	0	0	0	0	0	213
45%	0	0	0	0	0	0	0	0	0	0	0	0	861
50%	0	0	0	0	0	0	0	0	0	0	0	0	1,513
55%	0	0	177	0	0	0	0	0	0	0	0	0	2,346
60%	0	0	682	0	0	0	0	0	0	0	0	0	3,138
65%	0	0	1,157	0	0	0	0	0	0	0	0	0	4,149
70%	0	0	1,677	0	341	0	0	0	0	0	0	0	5,150
75%	0	0	2,294	0	3,748	0	0	0	0	0	0	0	6,472
80%	0	0	2,894	0	5,248	0	0	0	0	0	0	0	9,199
85%	0	0	3,749	0	6,942	0	0	0	0	0	0	0	13,465
90%	0	0	4,647	0	9,784	851	1,938	467	0	0	0	0	21,546
95%	0	0	5,930	4,786	14,657	1,824	6,854	2,599	0	0	0	0	30,424
97.5%	0	0	7,512	11,714	19,438	2,440	9,911	3,849	0	0	0	0	39,740
99%	0	374	9,688	18,055	25,617	3,352	13,892	5,217	0	0	0	197	52,946

Table 6.50: Forecasted HLH Power Purchase Statistics For FY 2006 (aMW)													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Annual
Average	0	0	1	54	250	26	18	0	0	0	0	0	28
Median	0	0	0	0	0	0	0	0	0	0	0	0	0
StDev	0	0	11	200	424	92	96	0	0	0	0	1	50
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	0	0	0	0	0	0	0	0	0	0	0	0	0
20%	0	0	0	0	0	0	0	0	0	0	0	0	0
25%	0	0	0	0	0	0	0	0	0	0	0	0	0
30%	0	0	0	0	0	0	0	0	0	0	0	0	0
35%	0	0	0	0	0	0	0	0	0	0	0	0	0
40%	0	0	0	0	0	0	0	0	0	0	0	0	0
45%	0	0	0	0	0	0	0	0	0	0	0	0	0
50%	0	0	0	0	0	0	0	0	0	0	0	0	0
55%	0	0	0	0	0	0	0	0	0	0	0	0	0
60%	0	0	0	0	0	0	0	0	0	0	0	0	0
65%	0	0	0	0	0	0	0	0	0	0	0	0	0
70%	0	0	0	0	260	0	0	0	0	0	0	0	23
75%	0	0	0	0	384	0	0	0	0	0	0	0	33
80%	0	0	0	0	538	0	0	0	0	0	0	0	53
85%	0	0	0	0	810	0	0	0	0	0	0	0	80
90%	0	0	0	0	998	79	0	0	0	0	0	0	107
95%	0	0	0	587	1,209	176	54	0	0	0	0	0	146
97.5%	0	0	0	787	1,337	292	290	0	0	0	0	0	175
99%	0	0	0	1,024	1,535	516	535	0	0	0	0	0	200

Table 6.51: Forecasted HLH Power Purchase Expense Statistics For FY 2006 ($ Thousand)													
	Oct	**Nov**	**Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**June**	**July**	**Aug**	**Sep**	**Total**
Average	0	0	14	1,285	4,008	377	280	0	0	0	0	1	5,963
Median	0	0	0	0	0	0	0	0	0	0	0	0	0
StDev	0	0	235	4,969	7,412	1,412	1,549	0	0	0	0	23	11,866
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	0	0	0	0	0	0	0	0	0	0	0	0	0
20%	0	0	0	0	0	0	0	0	0	0	0	0	0
25%	0	0	0	0	0	0	0	0	0	0	0	0	0
30%	0	0	0	0	0	0	0	0	0	0	0	0	0
35%	0	0	0	0	0	0	0	0	0	0	0	0	0
40%	0	0	0	0	0	0	0	0	0	0	0	0	0
45%	0	0	0	0	0	0	0	0	0	0	0	0	0
50%	0	0	0	0	0	0	0	0	0	0	0	0	0
55%	0	0	0	0	0	0	0	0	0	0	0	0	0
60%	0	0	0	0	0	0	0	0	0	0	0	0	0
65%	0	0	0	0	0	0	0	0	0	0	0	0	0
70%	0	0	0	0	3,589	0	0	0	0	0	0	0	4,211
75%	0	0	0	0	5,699	0	0	0	0	0	0	0	6,584
80%	0	0	0	0	8,048	0	0	0	0	0	0	0	9,967
85%	0	0	0	0	11,363	0	0	0	0	0	0	0	15,904
90%	0	0	0	0	14,950	1,060	0	0	0	0	0	0	21,681
95%	0	0	0	11,705	19,980	2,406	866	0	0	0	0	0	31,946
97.5%	0	0	0	19,218	24,271	4,117	4,684	0	0	0	0	0	41,741
99%	0	0	0	25,962	30,470	6,875	7,513	0	0	0	0	0	54,443

Table 6.52: Forecasted LLH Power Purchase Statistics For FY 2006 (aMW)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Annual
Average	2	2	182	82	159	59	35	3	0	0	0	36	46
Median	0	0	123	0	0	0	0	0	0	0	0	0	30
StDev	13	18	203	216	286	138	110	23	4	0	0	57	54
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	0	0	0	0	0	0	0	0	0	0	0	0	0
20%	0	0	0	0	0	0	0	0	0	0	0	0	0
25%	0	0	0	0	0	0	0	0	0	0	0	0	2
30%	0	0	0	0	0	0	0	0	0	0	0	0	8
35%	0	0	0	0	0	0	0	0	0	0	0	0	13
40%	0	0	21	0	0	0	0	0	0	0	0	0	18
45%	0	0	74	0	0	0	0	0	0	0	0	0	24
50%	0	0	123	0	0	0	0	0	0	0	0	0	30
55%	0	0	162	0	0	0	0	0	0	0	0	0	34
60%	0	0	202	0	0	0	0	0	0	0	0	0	40
65%	0	0	243	0	0	0	0	0	0	0	0	25	47
70%	0	0	283	0	124	0	0	0	0	0	0	46	55
75%	0	0	329	0	220	0	0	0	0	0	0	68	64
80%	0	0	370	0	362	56	0	0	0	0	0	87	81
85%	0	0	410	150	477	126	0	0	0	0	0	104	96
90%	0	0	464	360	614	248	144	0	0	0	0	121	124
95%	0	0	556	594	799	420	290	0	0	0	0	153	166
97.5%	2	12	646	808	929	508	397	0	0	0	0	186	194
99%	71	108	783	992	1,132	557	537	110	0	0	0	224	231

Table 6.53: Forecasted LLH Power Purchase Expense Statistics For FY 2006 ($ Thousand)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	19	28	2,283	1,174	1,636	553	342	26	1	0	0	418	6,480
Median	0	0	1,387	0	0	0	0	0	0	0	0	0	3,793
StDev	161	207	2,718	3,257	3,133	1,363	1,104	215	34	0	0	703	8,201
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	0	0	0	0	0	0	0	0	0	0	0	0	0
20%	0	0	0	0	0	0	0	0	0	0	0	0	0
25%	0	0	0	0	0	0	0	0	0	0	0	0	256
30%	0	0	0	0	0	0	0	0	0	0	0	0	985
35%	0	0	0	0	0	0	0	0	0	0	0	0	1,759
40%	0	0	226	0	0	0	0	0	0	0	0	0	2,355
45%	0	0	811	0	0	0	0	0	0	0	0	0	3,111
50%	0	0	1,387	0	0	0	0	0	0	0	0	0	3,793
55%	0	0	1,883	0	0	0	0	0	0	0	0	0	4,563
60%	0	0	2,309	0	0	0	0	0	0	0	0	3	5,397
65%	0	0	2,820	0	0	0	0	0	0	0	0	248	6,379
70%	0	0	3,397	0	1,043	0	0	0	0	0	0	486	7,627
75%	0	0	3,919	0	2,069	0	0	0	0	0	0	707	8,898
80%	0	0	4,522	0	3,294	523	0	0	0	0	0	913	10,598
85%	0	0	5,231	1,923	4,584	1,146	0	0	0	0	0	1,152	13,311
90%	0	0	6,133	4,705	6,153	2,260	1,229	0	0	0	0	1,452	17,228
95%	0	0	7,556	8,336	8,475	3,883	2,721	0	0	0	0	1,860	24,382
97.5%	20	139	8,710	12,183	10,821	4,906	4,078	0	0	0	0	2,334	30,055
99%	735	1,229	10,316	15,964	13,490	6,082	5,498	1,039	0	0	0	2,855	38,963

Table 6.54: Forecasted Total Power Purchase Statistics For FY 2006 (aMW)													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	1	1	78	66	211	40	25	1	0	0	0	15	35
Median	0	0	53	0	0	0	0	0	0	0	0	0	14
StDev	6	8	88	201	359	83	90	10	2	0	0	24	50
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	0	0	0	0	0	0	0	0	0	0	0	0	0
20%	0	0	0	0	0	0	0	0	0	0	0	0	0
25%	0	0	0	0	0	0	0	0	0	0	0	0	1
30%	0	0	0	0	0	0	0	0	0	0	0	0	4
35%	0	0	0	0	0	0	0	0	0	0	0	0	6
40%	0	0	9	0	0	0	0	0	0	0	0	0	9
45%	0	0	32	0	0	0	0	0	0	0	0	0	12
50%	0	0	53	0	0	0	0	0	0	0	0	0	14
55%	0	0	69	0	0	0	0	0	0	0	0	0	18
60%	0	0	86	0	0	0	0	0	0	0	0	1	21
65%	0	0	104	0	0	0	0	0	0	0	0	11	27
70%	0	0	121	0	261	21	0	0	0	0	0	20	33
75%	0	0	141	0	309	47	0	0	0	0	0	29	44
80%	0	0	158	0	407	76	0	0	0	0	0	37	64
85%	0	0	176	65	653	101	0	0	0	0	0	44	86
90%	0	0	199	168	824	156	70	0	0	0	0	52	112
95%	0	0	238	575	1,025	206	167	0	0	0	0	66	148
97.5%	1	5	277	808	1,156	246	287	0	0	0	0	80	182
99%	30	46	343	1,013	1,369	354	440	47	0	0	0	96	212

Table 6.55: Forecasted Total Power Purchase Expense Statistics For FY 2006 ($ Thousand)													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Total
Average	19	28	2,297	2,459	5,643	930	621	26	1	0	0	419	12,443
Median	0	0	1,387	0	0	0	0	0	0	0	0	0	4,496
StDev	161	207	2,781	8,004	10,413	2,108	2,346	215	34	0	0	703	19,424
1%	0	0	0	0	0	0	0	0	0	0	0	0	0
2.5%	0	0	0	0	0	0	0	0	0	0	0	0	0
5%	0	0	0	0	0	0	0	0	0	0	0	0	0
10%	0	0	0	0	0	0	0	0	0	0	0	0	0
15%	0	0	0	0	0	0	0	0	0	0	0	0	0
20%	0	0	0	0	0	0	0	0	0	0	0	0	0
25%	0	0	0	0	0	0	0	0	0	0	0	0	277
30%	0	0	0	0	0	0	0	0	0	0	0	0	1,121
35%	0	0	0	0	0	0	0	0	0	0	0	0	1,901
40%	0	0	226	0	0	0	0	0	0	0	0	0	2,707
45%	0	0	811	0	0	0	0	0	0	0	0	0	3,615
50%	0	0	1,387	0	0	0	0	0	0	0	0	0	4,496
55%	0	0	1,883	0	0	0	0	0	0	0	0	0	5,606
60%	0	0	2,309	0	0	0	0	0	0	0	0	16	7,072
65%	0	0	2,820	0	0	0	0	0	0	0	0	248	8,726
70%	0	0	3,397	0	5,636	460	0	0	0	0	0	486	10,724
75%	0	0	3,919	0	7,788	1,011	0	0	0	0	0	707	14,362
80%	0	0	4,522	0	10,805	1,642	0	0	0	0	0	913	19,958
85%	0	0	5,231	1,947	15,560	2,271	0	0	0	0	0	1,152	28,209
90%	0	0	6,138	5,544	20,956	3,332	1,630	0	0	0	0	1,453	38,524
95%	0	0	7,556	19,375	28,040	4,841	4,087	0	0	0	0	1,862	54,184
97.5%	20	139	8,778	31,021	34,402	6,217	6,896	0	0	0	0	2,336	69,908
99%	735	1,229	10,524	41,663	43,962	9,100	11,208	1,039	0	0	0	2,855	93,765