**2010 BPA Rate Case
Wholesale Power Rate Final Proposal**

RISK ANALYSIS AND MITIGATION STUDY DOCUMENTATION
Volume 1

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RISK ANALYSIS AND MITIGATION STUDY DOCUMENTATION VOLUME 1

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COMMONLY USED ACRONYMS

AC	alternating current
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
ATC	Accrual to Cash
BAA	Balancing Authority Area
BASC	BPA Average System Cost
Bcf	billion cubic feet
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	combined-cycle combustion turbine
cfs	cubic feet per second
CGS	Columbia Generating Station
CHJ	Chief Joseph
C/M	consumers per mile of line ratio for LDD
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Conservation Rate Credit
CRFM	Columbia River Fish Mitigation
CRITFC	Columbia River Inter-Tribal Fish Commission
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DC	direct current
DDC	Dividend Distribution Clause
dec	decremental (pertains to generation movement)
DJ	Dow Jones
DO	Debt Optimization
DOE	Department of Energy
DOP	Debt Optimization Program

DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EAF	energy allocation factor
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc. (formerly Washington Public Power Supply System)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
F&O	financial and operating reports
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FELCC	firm energy load carrying capability
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GAAP	Generally Accepted Accounting Principles
GARD	Generation and Reserves Dispatch (computer model)
GCL	Grand Coulee
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	generator step-up transformers
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	heavy load hour
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydro Simulation (computer model)
IDC	interest during construction
inc	incremental (pertains to generation movement)
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRP	Integrated Resource Plan
ISD	incremental standard deviation
ISO	Independent System Operator
JDA	John Day
kaf	thousand (kilo) acre-feet

kcfs	thousand (kilo) cubic feet per second
K/I	kilowatthour per investment ratio for LDD
ksfd	thousand (kilo) second foot day
kV	kilovolt (1000 volts)
kVA	kilo volt-ampere (1000 volt-amperes)
kVAr	kilo-volt ampere reactive
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LGIP	Large Generator Interconnection Procedures
LLH	light load hour
LME	London Metal Exchange
LOLP	loss of load probability
LRA	Load Reduction Agreement
m/kWh	mills per kilowatthour
MAE	mean absolute error
Maf	million acre-feet
MCA	Marginal Cost Analysis
MCN	McNary
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool
MMBtu	million British thermal units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MOU	Memorandum of Understanding
MRNR	Minimum Required Net Revenue
MVA	mega-volt ampere
MVAr	mega-volt ampere reactive
MW	megawatt (1 million watts)
MWh	megawatthour
NCD	non-coincidental demand
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NIFC	Northwest Infrastructure Financing Corporation
NLSL	New Large Single Load
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries (officially National Marine Fisheries Service)
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC	Northwest Power and Conservation Council

NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OMB	Office of Management and Budget
OTC	Operating Transfer Capability
OY	operating year (August through July)
PDP	proportional draft points
PF	Priority Firm Power (rate)
PI	Plant Information
PMA	(Federal) Power Marketing Agency
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PS	BPA Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	U.S. Bureau of Reclamation
RD	Regional Dialogue
REC	Renewable Energy Certificate
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
RMS	Remote Metering System
RMSE	root-mean squared error
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition

SCCT	single-cycle combustion turbine
Slice	Slice of the System (product)
SME	subject matter expert
TAC	Targeted Adjustment Charge
TDA	The Dalles
Tcf	trillion cubic feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
UAI	Unauthorized Increase
UDC	utility distribution company
URC	Upper Rule Curve
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WPRDS	Wholesale Power Rate Development Study
WREGIS	Western Renewable Energy Generation Information System
WSPP	Western Systems Power Pool

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1.   INTRODUCTION

The objective of the risk analysis is to identify, model, and analyze the impacts that key risks and risk mitigation tools have on Power Services (PS) net revenue (total revenues less total expenses). This is carried out in two distinct steps: a risk analysis step, in which the distributions, or profiles, of operating and non-operating risks are defined, and a risk mitigation step, in which different risk mitigation tools are tested to assess their ability to recover power costs in the face of this uncertainty.

Two statistical models are used in the risk analysis step for this rate proposal, the Risk Analysis Model (RiskMod) and the Non-Operating Risk Model (NORM). A third model, the ToolKit, is used to test the effectiveness of different risk mitigation tools in the risk mitigation step.

The Risk Analysis and Study Documentation (Study Documentation) is organized into volumes 1 and 2. Volume 1 presents additional discussion on the RiskMod processes and the interaction of this model with ToolKit. Volume 1 also presents a description of NORM's methodology. Volume 2 reports relevant output referenced in the Study and this volume of the Study Documentation.

1	**2.** **OPERATING RISK ANALYSIS (RISKMOD)**
2	
3	**2.1 RiskMod**
4	RiskMod is comprised of a set of risk simulation models, collectively referred to as RiskSim; a
5	set of computer programs that manages data referred to as Data Management Procedures; and
6	RevSim, a model that calculates net revenues. RiskMod interacts with AURORA$^{xmp®}$, the Rates
7	Analysis Model (RAM2010), and the ToolKit Model during the process of performing the Risk
8	Analysis and Mitigation Study (Study). AURORA$^{xmp®}$ is the computer model being used to
9	perform the Market Price Forecast Study (s*ee* Market Price Forecast Study, WP-10-FS-BPA-03);
10	the RAM2010 is the computer model being used to calculate rates (*see* Wholesale Power Rate
11	Development Study, WP-10-FS-BPA-05); and the ToolKit is the computer model being used to
12	develop the risk mitigation package that achieves BPA's 95.0 percent TPP standard (*see* Section
13	4 in the Study, WP-10-FS-BPA-04).
14	
15	Variations in monthly loads, resources, natural gas prices, and PS transmission and ancillary
16	service expenses are simulated in RiskSim. Monthly spot market electricity prices for the
17	simulated loads, resources, and natural gas prices are estimated by AURORA$^{xmp®}$. Data
18	Management Procedures facilitate the formatting and movement of data that flow to and/or from
19	RiskSim, AURORA$^{xmp®}$, and RevSim. RevSim uses risk data from RiskSim, spot market
20	electricity prices from AURORA$^{xmp®}$, loads and resources data from the Loads and Resources
21	Study, WP-10-FS-BPA-01, various revenues from the Revenue Forecast component of the
22	Wholesale Power Rate Development Study, WP-10-FS-BPA-05, and rates and expenses from
23	the RAM2010 to estimate net revenues.
24	
25	Annual average surplus energy revenues, balancing and augmentation purchased power
26	expenses, and section 4(h)(10)(C) credits calculated by RevSim are used in the Revenue Forecast
27	and the RAM2010. Heavy Load Hour (HLH) and Light Load Hour (LLH) surplus and deficit
28	energy values from RevSim are used in the PS Transmission and Ancillary Services Expense
29	Risk Model, which calculates the average PS transmission and ancillary services expenses used
30	in the Revenue Requirement Study, WP-10-FS-BPA-02. Net revenues estimated for each
31	simulation by RevSim are input into the ToolKit Model to develop the risk mitigation package
32	that achieves BPA's 95.0 percent TPP standard for the two year rate period. The processes and
33	interaction between each of the models and studies are depicted in Graph 1.
34	
35	**2.2 Risk Simulation Models (RiskSim)**
36	To quantify the effects of operating risks, risk models were developed that combine the use of
37	logic, econometrics, and probability distributions to quantify the ordinary operating risks that
38	BPA faces. Econometric modeling techniques are used to capture the dependency of values
39	through time. Parameters for the probability distributions were developed from historical data.
40	The values sampled from each probability distribution reflect their relative likelihood of
41	occurrence and are deviations from the base case values used in the Revenue Forecast, Revenue
42	Requirement, and AURORA$^{xmp®}$. *See* the Revenue Forecast component of the Wholesale
43	Power Rate Development Study, WP-10-FS-BPA-05; the Revenue Requirement Study, WP-10-
44	FS-BPA-02; and discussion of AURORA$^{xmp®}$ in the Market Price Forecast Study, WP-10-FS-
45	BPA-03.

The monthly output from these risk simulation models are accumulated into a computer file to form a risk database which contains values lower than, higher than, or equal to the base case values used in the Revenue Forecast component of the Wholesale Power Rate Development Study, Revenue Requirement Study, and AURORA$^{xmp®}$. *Id.* Loads, resources, and natural gas price risk data for each simulation are input into AURORA$^{xmp®}$ to estimate monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) spot market electricity prices. The prices estimated by AURORA$^{xmp®}$ are then downloaded into the risk database and a consistent set of loads, resources, and spot market electricity prices are used to calculate net revenues in RevSim. The risk models run 3,500 games to produce monthly risk data for the FY 2010-2011 rate period. Thus, each of the risk models produces 3,500 rows and 24 columns of simulated data.

2.3   @RISK Computer Software

Most of the risk simulation models developed to quantify operating risks were developed in Microsoft Excel workbooks using the add-in risk simulation computer package @RISK, which 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.

2.4   Operating Risk Factors

In the course of doing business, PS manages risks that are unique to operating a hydro system as large as the Federal Columbia River Power System (FCRPS). The variation in hydro generation due to the volume of water supply from one year to the next can be substantial. PS also faces other operating risks and variability that increase BPA's risk exposure, including the following: (1) Power Services' load variability due to changes in load growth and weather; (2) CGS nuclear plant generation; (3) wind generation and value of output; (4) augmentation costs; (5) Power Services' transmission and ancillary services expenses; (6) 4(h)(10)(C) credits; and (7) variability in electricity prices due to PNW and California load, resource, and natural gas price variability. The impacts of these risk factors on Power Services' net revenues are quantified in the Risk Analysis and Mitigation Study.

One major operating risk that is not quantified in this Risk Analysis and Mitigation Study is the change to hydro operations that could result from litigation of FCRPS BiOps. In its hydro regulation study, BPA has incorporated what it believes to be the most likely hydro operations for the rate period under the new 2008 BiOp. Details of the power and non-power requirements for the hydro regulation study for FY 2010-2011 are presented in the Loads and Resources Study, WP-10-FS-BPA-01, Section 2.3.2.1.1. For additional information on how BPA intends to respond to BiOp uncertainty, see the description of the NFB Mechanisms in Section 4 of the Risk Analysis and Mitigation Study, WP-10-FS-BPA-04.

The following is a discussion of the major risk factors included in RiskMod. Each of these risk factors is used in AURORA$^{xmp®}$, RevSim, or both.

2.4.1   PNW and Federal Hydro Generation Risk Factors

Federal hydro generation risk is 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 Study to account for the impact that various PNW hydro generation levels have on monthly HLH and LLH spot market electricity prices estimated by AURORA$^{xmp®}$.

2.4.1.1   Modeling Hydro Risk

Variability in Federal and PNW hydro generation is incorporated into RiskMod by using monthly Federal and PNW hydro generation data for each of the historical 70 water years from the Hydroregulation component of the Loads and Resources Study. *See* Loads and Resources Study, WP-10-FS-BPA-01, regarding 70 water years. The monthly hydro generation data for each of the 70 water years are developed in the HydroSim Model using hydro operations specified in the Load and Resource Study and historical monthly water supply for the 70 water years (1929-1998). *See* Loads and Resources Study, WP-10-FS-BPA-01, regarding HydroSim.

For each of the 70 water years, monthly HLH and LLH energy splits for the Federal system regulated hydro generation are developed for each year of the rate period based on HOSS analyses that incorporate the same HYDSIM hydro regulation studies as its base input. *See* Generation Inputs Study, WP-10-FS-BPA-08, section 3.3. These monthly HLH and LLH regulated hydro generation estimates are combined with monthly HLH and LLH independent hydro generation estimates developed from historical data to yield total monthly BPA HLH and LLH hydro generation. *See* the hydro-regulation component of the Loads and Resources Study, WP-10-FS-BPA-01, section 2.3.2.

A consistent set of monthly Federal and PNW hydro generation data for hydro operations in FY 2010 are randomly sampled, by water year, from tables containing hydro generation values for each of the 70 water years for 12 months of the year (70 X 12 tables). The 70 x 12 tables were derived from 70 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 70 x 12 table of HLH hydro generation ratios. 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 HLH. Given the HLH ratios, LLH ratios are calculated in RevSim. Tables 1-2 and Tables 3-4 contain the 70 x 12 tables of PNW and Federal hydro generation data for each year in the rate period. Similarly, Tables 5-6 contain the 70 x 12 table of HLH ratios for each year in the rate period.

Federal and PNW hydro generation data from the Hydroregulation component of the Loads and Resources Study are produced by performing a continuous study with the HydroSim Model. See Loads and Resources Study, WP-10-FS-BPA-01, regarding a continuous study by HydroSim.

The term "continuous study" refers to calculating hydro generation data sequentially over all 840 months of the 70 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 70 water year period.

2.4.1.2 Adjustments to Federal Hydro Generation Tables

The following two sections will discuss adjustments made to Federal hydro generation to account for refilling non-treaty storage in Canada and to account for efficiency losses associated with standing ready to provide and deploy within-hour balancing reserves for both load and wind generation variability and carrying the spinning portion of the operating reserves obligation. These generation adjustments are added to the values presented in Tables 3-4 to get the final Federal hydro generation for each of the 70 water years.

2.4.1.3 Non-Treaty Storage

Adjustments to Federal hydro generation were made for each water year during FY 2010-2011 to reflect the return of non-treaty storage. Since the non-treaty storage agreement expired in FY 2004, BPA is under an obligation to ensure that the storage balance is full by June 30, 2011. The current storage balance is 1002.1 ksfd (thousand second foot days) and a full balance is 1134 ksfd.

The method constructed to model the return of non-treaty storage attempts to minimize the total cost of this return. For FY 2009-2011, the results from the FY 2009 HYDSIM study and electricity prices estimated by AURORA$^{xmp®}$ were used in these computations. The basic model constructs 70 water year sequences that start in October 2008 and end in July 2011, with each water year incrementing after each October. For purposes of this analysis, it is assumed that 0 ksfd is returned in the remaining months of FY 2009 with the analysis focusing on the remainder to be returned in FY 2010-2011. Also, no storage was allowed in the April-August period since storage during those months could inhibit Biological Opinion flow objectives. The objective for the storage in the September-March period is to find the lowest cost time to return the remaining amount by July 2011.

Looking at price variability results from AURORA$^{xmp®}$ over the seventy water years, the standard deviations as a percentage of monthly average prices were determined for each month. These percentages were used to represent daily price variability and are listed in the following table.

	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Avg	5.7%	3.9%	2.9%	7.8%	11.1%	11.1%	11.2%

Given these daily price distributions, the amount of storage that needs to be returned, a maximal amount that can be stored each day (5 ksfd) and project/operational limitations (Chum, Vernita Bar, Canadian constraints), a daily plan for returning non-treaty storage can be developed for each sequence. These daily storage amounts are then averaged for each day of the month to

1	yield average monthly storage amounts. Since BPA is under an obligation to ensure that the
2	storage balance is full by June 30, 2011, the balance at the end of FY 2011 is 1134 ksfd.
3	
4	Given that BC Hydro also needs to return its storage, it is assumed that the amounts of these
5	returns are doubled. Even if BC Hydro does not match BPA's storage return over the course of
6	the month, there will be an energy delivery from BPA to BC hydro that is roughly equivalent to
7	the amount of lost Federal generation that would have occurred had they matched.
8	
9	These average monthly storage amounts are then multiplied by the Federal h/k (a measure of
10	electrical energy produced per unit of streamflow) reported by HYDSIM to create a matrix of
11	monthly adjustments to Federal hydro generation. The hydro generation adjustments associated
12	with refilling non-treaty storage during FY 2010-2011 are provided in Tables 7-8.
13	
14	**2.4.1.4 Generation Adjustment for Stand Ready & Deployment Losses**
15	Generation adjustments for stand ready and deployment losses, Bermejo *et a,,.* WP-10-E-BPA-
16	25, are included in this study to represent the losses of efficiency and value that occur as the
17	hydro system is set up to allow reserves to be deployed. Additional losses occur as the reserves
18	are actually deployed. Accounting for this variable cost component allows BPA to appropriately
19	allocate the cost of these losses to the parties who benefit from these changes to hydro
20	operations. A significant factor in these adjustments is the shift of hydro generation from HLH
21	to LLH. The generation adjustments, which include the HLH and LLH generation shifts, are
22	reported in terms of LLH, HLH, and Flat energy adjustments for FY 2010 in Tables 9-11 and
23	Tables 12-14 for FY 2011.
24	
25	**2.4.1.5 Sampling Hydro Generation**
26	Federal and PNW hydro generation variability is modeled in RiskMod by randomly sampling, in
27	the @RISK computer software, each of the 70 water years (1929-1998) and using the associated
28	hydro generation data in the same continuous manner that the data are developed by HydroSim
29	when performing a continuous study. The random selection of the initial water year (for
30	FY 2010) is accomplished by sampling integer values ranging from 1929-1998 from a uniform
31	probability distribution in a risk simulation model. Given the water year, the corresponding
32	monthly Federal and PNW hydro generation data and the HLH hydro generation ratios for that
33	water year are selected for the first year of the Rate Period (FY 2010). The uniform probability
34	distribution was selected for modeling hydro generation risk because it appropriately assigns
35	equal probability to each of the 70 water years being sampled. Graph 2 reports the number of
36	times that each of the 70 water years were sampled from a uniform probability distribution for
37	3,500 simulations. As shown in this graph, each of the 70 water years was sampled 50 times.
38	
39	After an initial water year is selected for FY 2010 for a given simulation, hydro generation data
40	for a sequential set of two water years, starting with the water year selected for FY 2010, are
41	selected from water years 1929-1998. When the end of the 70 water years is reached (at the end
42	of water year 1998), monthly hydro generation data for water year 1929 is subsequently used.
43	Thus, if a simulation starts with water year 1998, the simulation will use water years 1998 and
44	1929 for a total of two sequential water years. Using Federal and PNW hydro generation data in

1	this continuous manner captures the risk associated with various dry, normal, and wet weather
2	patterns over time that are reflected in the 70 water years of hydro generation data.
3	
4	Surplus energy revenues and balancing power purchase expenses reported in the Revenue
5	Forecast component of the Wholesale Power Rate Development Study and used in setting rates
6	in the RAM2010 are derived by performing a 70 water year run of RiskMod. *See* the Revenue
7	Forecast component of the Wholesale Power Rate Development Study, WP-10-FS-BPA-05; and
8	discussion of the RAM2010 components of the Wholesale Power Rate Development Study,
9	WP-10-FS-BPA-05.
10	
11	For the 70 water year run of RiskMod, average surplus energy revenues, 4(h)(10)(C) credits and
12	balancing power purchase expenses are estimated using Federal HLH and LLH hydro generation
13	for the 70 water years. No other risk factors, except for hydro generation, are allowed to vary
14	when performing the 70 water year run of RiskMod. HLH and LLH spot market electricity
15	prices estimated by AURORA$^{xmp®}$ using PNW hydro generation for the 70 water years are input
16	into RevSim and used to calculate surplus energy revenues, 4(h)(10)(C) credits, and balancing
17	power purchase expenses. Results from the 70 water year run of RiskMod for FY 2010 - 2011
18	are reported in the Revenue Forecast component of the Wholesale Power Rate Development
19	Study, WP-10-FS-BPA-05. Results from the 70 water year run of RiskMod for FY 2012 – 2015
20	are provided to RAM2010 to inform the 7(b)(2) rate test.
21	
22	The results provided to RAM2010 for FY 2012 – 2015 are as follows:
23	

	Federal Surplus Energy Revenues ($ Thousand)	Balancing Power Purchase Expenses ($ Thousand)	Winter Hedging Purchase Expense ($ Thousand)
FY 2012	635,998	40,383	43,421
FY 2013	668,226	32,761	43,138
FY 2014	697,343	43,462	35,294
FY 2015	697,968	43,069	0

2.4.1.6   Use of PNW Hydro Generation Risk in AURORA$^{xmp®}$

Variability in PNW hydro generation is incorporated into AURORA$^{xmp®}$ by calculating monthly energy ratio inputs from monthly PNW hydro generation data and PNW annual energy to capacity ratio inputs (using the total capacity value for all of the PNW in AURORA$^{xmp®}$) for each of the 70 water years. These sets of ratios are used by AURORA$^{xmp®}$ to calculate first the annual and then the monthly hydro generation for each of the three regions (Oregon/Washington/Northern Idaho, Southern Idaho, and Montana) for the PNW in AURORA$^{xmp®}$. This process results in the sum of the hydro generation for the three regions in AURORA$^{xmp®}$ being equal to the PNW hydro generation.

2.4.2   PNW and BPA Load Risk Factor

PNW load risk is incorporated into the Study to account for the impact that PNW load variability, which is simulated in the PNW Load Risk Model, has on monthly HLH and LLH spot market electricity prices, which impacts PS's surplus energy revenues and balancing power

purchase expenses. This impact is accounted for by inputting into AURORA$^{xmp®}$ various PNW load values and having it estimate the associated HLH and LLH spot market electricity prices.

BPA load risk is incorporated into the Study to account for the impact that monthly Non-Slice PF load variability has on Priority Firm Power (PF) revenues, surplus energy revenues, and balancing power purchase expenses. This impact is accounted for by inputting into RevSim various monthly load variability values that modify the amount of Non-Slice PF loads served by BPA.

2.4.2.1   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 AURORA$^{xmp®}$ 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/Northern Idaho, Southern Idaho, and Montana) that comprise the PNW in AURORA$^{xmp®}$. This process results in the simulated loads reflecting variability in loads relative to the forecasted loads that AURORA$^{xmp®}$ uses to perform the Market Price Forecast Study. *See* Market Price Forecast Study, WP-10-FS-BPA-03.

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 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 CY 2008-2011 and then, subsequently, simulating the impact of monthly load swings due to weather on the simulated monthly loads that include load growth.

Annual CY 2008 PNW load risk is accounted for in the risk analysis for the Final Study. This was done because the WECC 10-Year Coordinated Plan Summary (2006-2015) used in the Initial Proposal, which does not report actual CY 2008 loads, is the most recent summary published by the WECC (*see* Market Price Forecast Study, WP-10-FS-BPA-03, section 3.2.1). Since actual loads for the PNW in CY 2008 are unknown at the time the Final Study is being developed, this uncertainty is accounted for in this Study.

2.4.2.2   Annual PNW and BPA Load Growth Risk

Annual PNW (and indirectly BPA) load growth risk is modeled to simulate various load patterns through time using a mean-reverting, random-walk technique. The random-walk technique 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.

1	Under this method, simulated annual average loads randomly increase and decrease through time
2	from the annual average load level of the prior year with the results including outcomes that
3	represent periods of strong load growth, weak load growth, and vacillating positive and negative
4	load growth. The mean-reverting technique, used in conjunction with the random-walk
5	technique, allows the modeler to specify parameter values that control the otherwise
6	uncontrollable variability that results from using the random-walk technique. These parameter
7	values are calibrated such that the simulated variability in loads over time is consistent with the
8	variability reflected in historical load data.
9	
10	Input data from AURORA$^{xmp®}$ used in the PNW Load Risk Model are the following: (1) annual
11	average CY 2007 PNW load; (2) forecasted annual load growth for CY 2008-2011; and (3)
12	monthly load shaping factors (values relative to 1.00) that are derived for use in AURORA$^{xmp®}$
13	by dividing historical monthly loads by historical annual average loads. *See* Market Price
14	Forecast Study, WP-10-FS-BPA-03. Inputting the data used by AURORA$^{xmp®}$ allows the PNW
15	Load Risk Model to replicate the forecasted monthly PNW loads in AURORA$^{xmp®}$.
16	
17	Load growth variability is incorporated into the PNW Load Risk Model by sampling values from
18	standard normal distributions (normal distributions with a mean of zero and a standard deviation
19	of one) in @RISK, multiplying the sampled values by an annual load growth standard deviation,
20	and adding the simulated positive and negative values to the annual load level of the prior year.
21	The values sampled from the standard normal distribution are in terms of the number of positive
22	or negative standard deviations.
23	
24	The annual load growth standard deviation used in the PNW Load Risk Model is 2.42 percent
25	with the cumulative annual load growth standard deviations over two, three, and four year
26	durations being 2.69, 3.30, and 3.80 percent. These values were derived from historical annual
27	Western Electricity Coordinating Council (WECC) load data for the Northwest Power Pool Area
28	(NWPP) for CY 1985-2005 that were modified by removing historical annual DSI loads for
29	CY 1985-2005. The source of the NWPP data is a publication by the WECC titled, 10-Year
30	Coordinated Plan Summary, Planning and Operation for Electric System Reliability, Western
31	Electricity Coordinating Council, July 2006, at 61. The source for the historical annual DSI
32	loads is metered data that includes all DSI loads served by both federal and non-federal
33	purchases, except for DSI loads served by Chelan PUD at the Alcoa aluminum smelter located in
34	Wenatchee, Washington. Variability in monthly loads due to load growth risk is derived by
35	multiplying variable annual loads by deterministic monthly load shape factors. The historical
36	NWPP and DSI load data and the cumulative annual load growth standard deviation calculations
37	for the PNW are reported in Table 15**.**
38	
39	**2.4.2.3 PNW and BPA Load Risk Due to Weather**
40	Monthly PNW (and indirectly BPA) load variability due to weather conditions is quantified by
41	first sampling values from standard normal distributions in @RISK, then multiplying the
42	sampled values by monthly load standard deviations, and finally adding the resulting positive
43	and negative values to the simulated loads after load growth.
44	

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

8

9   **2.4.2.4   Derivation of PNW/BPA Monthly Load Variability Due to Weather**
10   BPA assumes, for rate setting purposes, that daily weather patterns over the course of a month
11   are independent and that each day of a given month has the same daily load standard deviation.
12   Accordingly, BPA used the following statistical equation to derive monthly load standard
13   deviations from daily load standard deviations for each month. The statistical equation for
14   calculating the standard deviation for the average of "n" number of independent random
15   variables is the following:

16

17
$$\sigma_{\bar{x}} = \frac{\sigma_x}{\sqrt{n}}$$

18   Where:

$$\sigma_x$$

19   is the standard deviation for all independent random variables

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

21

22   In the case of BPA's analysis, the number of independent random variables is the number of
23   days in a month and the standard deviation for all the independent random variables is the daily
24   load standard deviations for each month. The PNW monthly load standard deviations for each
25   month are derived by inserting values for the number of days in each month and the daily load
26   standard deviations for each month into the equation above. Table 16 contains the calculations
27   performed to derive PNW monthly load standard deviations from daily load standard deviations
28   for each month. These monthly load standard deviations are input into the PNW Load Risk
29   Model to quantify monthly load variability due to weather.

30

31   **2.4.2.5   Modeling Methodology**
32   In order for the PNW Load Risk Model to simulate the cumulative annual load growth standard
33   deviations reflected in the historical data over various time durations, mean-reversion decay
34   parameters were developed so that the simulated cumulative annual load growth standard
35   deviations for years two through four (CY 2009-2011) would be calibrated to the values in the
36   historical data. No mean-reversion decay parameter was developed for year 1, since the load
37   growth standard deviation used in the probability distributions is the annual load growth standard
38   deviation for a year.

The mean-reversion methodology incorporated into the standard normal probability distributions is as follows:

Sampled positive or negative standard deviation = RiskNormal (Annual mean-reversion decay parameters * (1 - Simulated mean-reversion ratios), 1)

Where:

RiskNormal = Normal probability distribution in @RISK with
Mean = Annual mean-reversion decay parameters * (1 - Simulated mean-reversion ratios)
Standard deviation = 1
Mean-reversion decay parameters = Calibrated annual load decay values
Simulated mean-reversion ratios = Simulated prior annual load / Forecasted prior annual load

Annual load movements through time were modeled as follows:

Annual load for time t = Annual load for time t-1 * (1 + (Forecasted load growth from time t-1 to time t + (Sampled positive or negative standard deviation * annual load growth standard deviation)))

2.4.2.6 Calibrating Annual Load Variability

The final step in the modeling process is the derivation of annual decay parameters to better calibrate the cumulative annual load variability simulated by the PNW Load Risk Model to the historical cumulative annual load variability reflected in the WECC annual load data. The calibration of the annual decay values is performed in the following manner: (1) run the model; (2) calculate the cumulative annual load standard deviations for the simulated data and compare these results to the cumulative annual load standard deviations derived by multiplying the forecasted annual loads times the historical cumulative annual load standard deviations; and (3) revise the annual decay values for CY 2009-2011 to test how well the values computed in step (2) compare.

The statistical approach of minimizing the sum of residuals squared was used to help objectively determine the relative merits of one set of annual decay values versus another. The sum of residuals squared is calculated by squaring the difference between the values computed in Step (2) above and summing these squared differences. The lower the sum of residuals squared, the better the results.

2.4.2.7 Model and Results

Tables 17 and 18 contain copies of the results of the calibration process for PNW load variability and the PNW Load Risk Model. Graph 3 shows the simulated PNW loads at the 5th, 50th, and 95th percentiles.

2.4.2.8   Use of Simulated PNW Loads in AURORA$^{xmp®}$

The HLH and LLH spot market electricity prices associated with changes in PNW monthly loads are estimated in AURORA$^{xmp®}$ by inputting PNW load data simulated by the PNW Load Risk Model. This process involves calculating 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 AURORA$^{xmp®}$ for each simulation. These data are input into AURORA$^{xmp®}$ to calculate annual and monthly loads for each of the three PNW regions (Oregon/Washington/Northern Idaho, Southern Idaho, and Montana) in AURORA$^{xmp®}$. This process results in the sum of the loads for the three PNW regions in AURORA$^{xmp®}$ being equal to the simulated PNW loads from the PNW Load Risk Model.

2.4.3   California Hydro Generation Risk Factor

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

2.4.3.1   Modeling Hydro Risk

California hydro generation risk is incorporated into the Study by sampling 18 years of historical monthly California hydro generation data and estimating the associated monthly HLH and LLH spot market electricity prices in AURORA$^{xmp®}$. The historical monthly California hydro generation data used to incorporate risk was collected from reports published by the Energy Information Administration (EIA) for 1980-1997 and they are reported in Table 19.

2.4.3.2   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 70 water year analysis. The random selection of the initial hydro generation year (for FY 2010) is accomplished by sampling integer values ranging from 1 to 18 from a uniform probability distribution in a risk simulation model. Given the sampled hydro generation year, the corresponding monthly California hydro generation data for that year are selected for the first year of the rate period (FY 2010).

Graph 4 reports the number of times that each of the 18 years of hydro generation data were sampled from a uniform probability distribution for 3,500 simulations. The uniform probability distribution was selected for use in the risk simulation model because it appropriately assigns 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 3,500 simulations is 194.4 (3,500/18). These results in Graph 4 indicate that all years were sampled either 194 or 195 times.

After the initial year is selected for FY 2010 for a given simulation, hydro generation data for a sequential set of two years of data, starting with the hydro generation year selected for FY 2010, 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 one is subsequently used. Thus, if a simulation
starts with hydro generation data for hydro generation year 18, the simulation will use hydro
generation data for years 18 and 1 for a total of two sequential years of hydro generation data.
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.

2.4.3.3 Use of California Hydro Generation Risk in AURORA$^{xmp®}$

Variability in California hydro generation is incorporated into AURORA$^{xmp®}$ by calculating
monthly energy ratios from monthly California hydro generation data and California annual
energy to capacity ratios (using the total capacity value for all of California in AURORA$^{xmp®}$)
for each of the 18 water years. These sets of ratios are used by AURORA$^{xmp®}$ to calculate the
annual and then the monthly hydro generation for each of the two California regions (northern
and southern California) in AURORA$^{xmp®}$. This process results in the sum of the hydro
generation for the two California regions in AURORA$^{xmp®}$ being equal to the historical monthly
California hydro generation.

2.4.4   California Load Risk Factor

California load risk is incorporated into the Study to account for the impact that California load
variability has on monthly HLH and LLH spot market electricity prices, which impacts BPA's
surplus energy revenues and balancing power purchase expenses. This impact is accounted for
by inputting into AURORA$^{xmp®}$ various California load values and having it estimate the
associated HLH and LLH spot market electricity prices.

2.4.4.1   California Load Variability

The California Load Risk Model is designed to incorporate forecasted monthly load data from
AURORA$^{xmp®}$ 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 AURORA$^{xmp®}$. This process results in the simulated loads reflecting
variability in loads relative to the forecasted loads that AURORA$^{xmp®}$ uses to perform the Market
Price Forecast Study. *See* Market Price Forecast Study, WP-10-FS-BPA-03.

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 CY 2008-2011 and then, subsequently, simulating the impact of monthly
load swings due to weather on the simulated monthly loads that include load growth.

Annual CY 2008 California load risk is accounted for in the risk analysis for the Final Study.
This was done because the WECC 10-Year Coordinated Plan Summary (2006-2015) used in the
Initial Proposal, which does not report actual CY 2008 loads, is the most recent summary
published by the WECC (*see* Market Price Forecast Study, WP-10-FS-BPA-03, section 3.2.1).
Since actual loads for California in CY 2008 are unknown at the time the Final Study is being
developed, this uncertainty is accounted for in this Study.

1	**2.4.4.2 Annual California Load Growth Risk**
2	Annual California load growth risk is modeled to simulate various load patterns through time
3	using a mean-reverting, random-walk technique. The random-walk technique simulates various
4	annual average load levels through time with the starting point for simulating the annual average
5	load in a given year being the annual average load level from the previous year. Under this
6	method, simulated annual average loads randomly increase and decrease through time from the
7	annual average load level of the prior year with the results including outcomes that represent
8	periods of strong load growth, weak load growth, and vacillating positive and negative load
9	growth. The mean-reverting technique, used in conjunction with the random-walk technique,
10	allows the modeler to specify parameter values that control the otherwise uncontrollable
11	variability that results from using the random-walk technique. These parameter values are
12	calibrated such that the simulated variability in loads over time is consistent with the variability
13	reflected in historical load data.
14	
15	Input data from AURORA$^{xmp®}$ used in the California Load Risk Model are the following: (1)
16	annual average CY 2007 California loads; (2) forecasted annual load growth for CY 2008-2011;
17	and (3) monthly load shaping factors (values relative to 1.00) that are derived for use in
18	AURORA$^{xmp®}$ by dividing historical monthly loads by historical annual average loads
19	(*see* Market Price Forecast Study, WP-10-FS-BPA-03). Inputting the data used by
20	AURORA$^{xmp®}$ allows the California Load Risk Model to replicate the forecasted monthly
21	California loads in AURORA$^{xmp®}$.
22	
23	Load growth variability is incorporated into the California Load Risk Model by multiplying an
24	annual load growth standard deviation by values sampled from standard normal distributions
25	(normal probability distributions with a mean of zero and a standard deviation of one) in @RISK
26	and adding the simulated positive and negative values to the annual load level of the prior year.
27	The values sampled from the standard normal distribution are in terms of the number of positive
28	or negative standard deviations.
29	
30	The annual load growth standard deviation used in the California Load Risk Model is
31	2.51 percent with cumulative annual load growth standard deviations over two, three, and four
32	years being 2.35, 2.74, and 2.42 percent. These values were derived from historical annual
33	Western Electricity Coordinating Council (WECC) load data for the California/Mexico Power
34	Area during 1987-2005. The source of this data was a publication by the WECC titled, 10-Year
35	Coordinated Plan Summary, Planning and Operation for Electric System Reliability, Western
36	Electricity Coordinating Council, July 2006, at 61. Variability in monthly loads due to load
37	growth variability is derived by multiplying variable annual loads by deterministic monthly load
38	shape factors. The historical WECC load data and the cumulative annual load growth standard
39	deviation calculations by BPA for California, along with the PNW, are reported in Table 15.
40	
41	**2.4.4.3 California Load Risk Due to Weather**
42	Monthly California load variability due to weather conditions is quantified by first sampling
43	values from standard normal distributions in @RISK, then multiplying the sampled values
44	sampled by monthly load standard deviations, and finally adding the resulting positive and
45	negative values to the simulated loads after load growth.

1	
2	The monthly California load standard deviations are derived from utility-specific, monthly,
3	historical daily load standard deviations and forecasted CY 2005 loads for California utilities,
4	which were used as input data in PMDAM when performing the MCA in the 1996 rate case (*see*
5	Marginal Cost Analysis Study Documentation, WP-96-FS-BPA-04A, Part 2 of 2; pages 305 and
6	256). This derivation is accomplished by calculating composite, load-weighted, monthly load
7	standard deviations from utility specific, daily load standard deviations (for the 12 months of the
8	year) and annual average load data.
9	

2.4.4.4 Derivation of California Monthly Load Variability Due to Weather

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:

σ_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 20. These monthly load standard deviations are input into the California Load Risk Model to quantify monthly load variability due to weather.

2.4.4.5 Modeling Methodology

Based on a correlation analysis of annual California and PNW loads (with DSI loads removed) from 1987-2005 that indicates these loads are highly correlated (the correlation coefficient between these loads is 0.971 (*See* Table 15), the values sampled from the standard normal distributions for California are identical (including the mean-reversion impacts) to the values sampled from the standard normal distributions used to estimate annual 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. With the

strong relationship between these loads modeled, additional annual load variability adjustment factors were developed for years two through four (CY 2009-2011) in the California Load Risk Model to more closely match the simulated load growth standard deviations for California to the load growth standard deviations in the historical data.

Annual load movements through time were modeled as follows:

Annual load for time t = Annual load for time t-1 * (1 + (Forecasted load growth from time t-1 to time t + (Sampled positive or negative standard deviation * annual load growth standard deviation)))

Where,

The sampled positive or negative standard deviation is the same as for the PNW, but is adjusted by additional annual load variability adjustment factors.

2.4.4.6   Calibrating Annual Load Variability

The final step in the modeling process is the derivation of annual load variability adjustment factors, which are used to better calibrate the cumulative annual load variability simulated by the California Load Risk Model to the historical annual variability reflected in the WECC annual load data. The calibration of the cumulative annual load variability adjustment factors is performed in the following manner: (1) run the model; (2) calculate the cumulative annual load standard deviations for the simulated data and compare these results to the annual load standard deviations derived by multiplying the forecasted annual loads times the historical cumulative annual load standard deviations; and (3) revise the annual load variability adjustment factors for CY 2009-2011 to test how well the values computed in step (2) compare.

The statistical approach of minimizing the sum of residuals squared was used to help objectively determine the relative merits of one set of annual decay values versus another. The sum of residuals squared is calculated by squaring the difference between the values computed in Step (2) above and summing these squared differences. The lower the sum of residuals squared, the better the results.

2.4.4.7   Model and Results

Table 17 and Table 21 contain copies of the results of the calibration process for California load variability and the California Load Risk Model. Graph 5 shows the simulated California loads at the 5th, 50th, and 95th percentiles.

2.4.4.8   Use of Simulated California Loads in AURORA$^{xmp®}$

The HLH and LLH spot market electricity prices associated with changes in California monthly loads are estimated in AURORA$^{xmp®}$ by inputting California load data simulated by the California Load Risk Model. This process involves calculating 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 AURORA$^{xmp®}$ for each simulation. These data are input into AURORA$^{xmp®}$ to

1	calculate annual and monthly loads for each of the two California regions (southern and northern
2	California) in AURORA$^{xmp®}$. This process results in the sum of the loads for the two California
3	regions in AURORA$^{xmp®}$ being equal to the simulated California loads from the California Load
4	Risk Model.
5	
6	**2.4.5 Natural Gas Price Risk Factor**
7	Natural gas price risk is incorporated into the Study to account for the impact that natural gas
8	price variability has on monthly HLH and LLH spot market electricity prices, which impacts
9	PS's surplus energy revenues and balancing power purchase expenses. This impact is accounted
10	for by inputting into AURORA$^{xmp®}$ the simulated monthly natural gas prices (in real 2005
11	dollars) from the Natural Gas Price Risk Model and having AURORA$^{xmp®}$ estimate the
12	associated nominal monthly HLH and LLH spot market electricity prices for each simulation.
13	
14	The Natural Gas Price Risk Model is designed to simulate various gas price patterns through
15	time. The modeling method used to simulate gas price patterns through time is a mean-reverting,
16	random-walk technique. The random-walk technique simulates monthly natural gas prices
17	through time with the starting point for simulating the natural gas price in a given month being
18	the monthly natural gas price from the prior month. Under this method, simulated monthly
19	natural gas prices randomly increase and decrease through time from the natural gas price of the
20	prior month. The mean-reverting technique, used in conjunction with the random-walk
21	technique, allows the modeler to specify parameter values that control the otherwise
22	uncontrollable variability that results from using the random-walk technique. These parameter
23	values are calibrated such that the simulated variability in natural gas prices over time is
24	consistent with the variability reflected in historical natural gas price data.
25	
26	**2.4.5.1 Inputs into the Natural Gas Price Risk Model**
27	The Natural Gas Price Risk Model is designed to simulate variable natural gas prices based on
28	natural gas prices used in AURORA$^{xmp®}$ to perform the Market Price Forecast Study (*see* Market
29	Price Forecast Study, WP-10-FS-BPA-03). To accomplish this task, forecasted annual median
30	delivered natural gas prices (in real 2005 dollars) to southern California for CY 2008-2011 and
31	monthly gas price shape data (values relative to 1.00) from the natural gas price forecast are
32	input into the Natural Gas Price Risk Model. *Id.* With this data, the deterministic forecasted
33	monthly prices in AURORA$^{xmp®}$ are calculated in the Natural Gas Price Risk Model by
34	multiplying the annual median natural gas prices by the monthly gas price shapes. *Id.*
35	
36	Additional information input into the Natural Gas Price Risk Model are minimum and maximum
37	delivered natural gas price constraints (in real 2005 dollars) and monthly price volatilities for
38	natural gas prices, which were derived from historical monthly spot market natural gas prices by
39	computing the standard deviations of all the natural log (ln) price ratio changes from one month
40	to the next month. These natural log price ratio changes (ln (price at time t/price at time t-1)) are
41	commonly referred to as "returns" in the technical literature. Accordingly, they will be referred
42	to as returns in this study.
43	
44	Minimum and maximum delivered gas price constraints used in the Natural Gas Risk Model are
45	\$1.75/MMBTU (Million British Thermal Units) and \$50.00/MMBTU. The minimum price

1	constraint was set based on reviewing the historical real 2005 dollar prices at Ignacio, Colorado
2	(*see* Table 22) and adding an additional charge for delivery from Ignacio to southern California
3	and the maximum price constraint was set such that no simulated prices would be constrained.
4	
5	Historical monthly spot market gas prices in real 2005 dollars for Ignacio, Colorado, from
6	December 1989 through December 2007 were used to calculate the monthly price volatilities for
7	month-to-month price movements. Monthly price volatilities were estimated in terms of
8	month-to-month price changes so that price movements through time could be modeled using the
9	random-walk technique.
10	
11	**2.4.5.2 Modeling Natural Gas Price Volatility and Variability**
12	Statistical parameters needed to quantify risk in probability distributions in the Natural Gas Price
13	Risk Model were developed from the Ignacio price data. This quantification allows the volatility
14	in the historical natural gas price data for Ignacio to be incorporated into the Natural Gas Price
15	Risk Model. This process was performed in the following manner: (1) all the returns from one
16	month to the next month for all months from December 1989 through December 2007 were
17	calculated; (2) all the returns were accumulated, by month, for each of the 12 months in a year;
18	and (3) the standard deviation of all the returns from one month to the next month for each
19	month were calculated. This process resulted in monthly price volatilities being calculated from
20	a set of 16 price changes for all months of the year. Using a similar approach with annual price
21	data, cumulative annual price volatilities over several years duration were computed to quantify
22	how much annual prices could deviate in the future from the current natural gas price forecast.
23	
24	Table 22 contains the historical Ignacio monthly spot market natural gas prices, the calculations
25	of the month-to-month returns, and the derivation of the monthly price volatilities. Comparisons
26	between the average and median prices for the monthly and annual historical price data indicate
27	that average prices are greater than median prices. Additional comparisons indicate that the
28	differences between the maximum prices and the median prices are greater than the differences
29	between the minimum prices and the median prices. These asymmetrical differences were
30	accounted for in this study by modeling natural gas price risk in lognormal probability
31	distributions that differ in skewness depending on the size of the differences.
32	
33	A comparison of the month-to-month volatilities in Table 22 reveals that, in general, month-to-
34	month price movements, either upward or downward, are greatest during the wintertime. At the
35	bottom of this table, the month-to-month returns were applied to the CY 2009 natural gas price
36	forecast to compute monthly price variability, annual price variability, and the annual price
37	volatility for CY 2009. As the values in this table indicate, price variability (as measured by
38	standard deviation) is impacted by both the volatility and the price level with price variability
39	increasing the higher the volatility and/or the price level.
40	
41	The results reported in Table 22 indicate that monthly and annual price variability at forecasted
42	CY 2009 prices are substantial with annual CY 2009 price variability being $1.16/MMBTU,
43	which translates into an annual price volatility of 30.4 percent. These results reflect how much
44	natural gas prices can vary from a gas price forecast made at the beginning of CY 2009. Natural
45	gas price variability was turned off in the Natural Gas Price Risk Model for the months of

1	January thru April of 2009 to account for the fact that there is less natural gas price risk for the
2	remainder of the year than for a full year.
3	
4	Table 23 contains the calculations of the cumulative annual price returns for one and two years
5	duration after the current calendar year (CY 2009) and the derivation of the associated
6	cumulative annual price volatilities. The cumulative annual price returns for one and two years
7	duration were derived by computing all the annual price returns over one- and two-year
8	increments and calculating the associated standard deviations to get the cumulative annual price
9	volatilities. These values were computed so that the simulated prices over various durations in
10	time would have values to calibrate to, rather than move through time in an unconstrained
11	manner. The cumulative annual price volatilities for one and two years duration after the current
12	calendar year (CY 2009) were calculated to be 30.2 percent for one year and 37.5 percent for two
13	years; which yields a 2 year average value of 33.9 percent.
14	
15	At the bottom of Table 23, the cumulative annual price returns for one and two years duration
16	after the current calendar year (CY 2009) were applied to the CY 2010-2011 natural gas price
17	forecast to compute the cumulative annual price variability over these years. This price
18	variability (as measured by standard deviation) is impacted by both the volatility and the price
19	level with price variability increasing the higher the volatility and/or the price level.
20	
21	Monthly gas price variability was incorporated into the Natural Gas Price Risk Model by
22	sampling positive and negative standard deviation values from truncated standard normal
23	probability distributions in @RISK, multiplying the sampled standard deviation values by
24	monthly price volatility values, and multiplying the natural gas price of the prior month by the
25	exponential of the simulated positive and negative values (which transforms values that are in
26	terms of natural logs into unlogged values). A truncated standard normal distribution is a normal
27	distribution having a mean of zero, a standard deviation of one, and a specified maximum and
28	minimum value that sets an upper and lower bound on the standard deviation values that can be
29	sampled. For this study, the specified maximum and minimum values were set at +5 and -5
30	standard deviations (which results in them having no impact), since controlling the maximum
31	and minimum standard deviations was not needed.
32	
33	In the @RISK computer software, this information is entered into a truncated standard normal
34	probability distribution (RiskTNormal) as follows:
35	
36	RiskTNormal (Mean = 0, Standard deviation = 1, Min value = -5, Max value = +5).
37	
38	Under this methodology, the positive and negative values sampled from the truncated standard
39	normal distributions are the number of standard deviations of a random price movement. The
40	standard deviations sampled from the monthly truncated standard normal distributions in the
41	Natural Gas Price Risk Model are multiplied by the monthly volatilities as part of the price
42	movement computations reported in the equation below.
43	

1	Prices movements through time are modeled as follows:
2	
3	Price t = Price t-1 * EXP (Sampled positive or negative standard deviation * monthly volatility)
4	+ (FP t minus FP t-1)
5	
6	Where:
7	Price t = Simulated price at time t
8	Price t-1 = Simulated price at time t-1
9	FP t = Forecasted price for time t
10	FP t-1 = Forecasted price for time t-1
11	EXP = Exponential Function (used to take the antilog of the returns; which are in logs)
12	
13	The mean-reversion methodology was modeled using an algorithm and a set of monthly and
14	annual mean reversion decay parameters (decay parameters) that adjust the value of the mean in
15	each of the monthly truncated standard normal distributions from the typical constant of zero.
16	
17	The mean-reversion methodology incorporated into the monthly truncated standard normal
18	probability distributions is as follows:
19	
20	Sampled positive or negative standard deviation = RiskTNormal (Mean-reversion decay
21	parameters * (1 - Simulated mean-reversion ratios), 1, Maximum negative monthly standard
22	deviation, Maximum positive monthly standard deviation)
23	
24	Where:
25	RiskTNormal = Truncated normal probability distribution in @RISK with
26	Mean = Mean-reversion decay parameters * (1- Simulated mean-reversion ratios)
27	Standard deviation = 1
28	Minimum value = - 5 standard deviations
29	Maximum value = + 5 standard deviations
30	Mean-reversion decay parameters = Calibrated price decay values
31	Simulated mean-reversion ratios = LN(Simulated prior month price) / LN(Forecasted prior
32	month price)
33	LN = Natural log function in Excel
34	

2.4.5.3   Calibrating Future Natural Gas Price Volatility

The final step in the modeling process is the derivation of monthly and annual decay parameters to better calibrate the natural gas price volatility simulated by the Natural Gas Price Risk Model to the historical volatility reflected in the Ignacio natural gas price data. The calibration of the decay values was performed in the following manner: (1) run the model; (2) calculate monthly and cumulative annual price volatilities from the simulated data and compare the results to monthly and cumulative annual price volatilities for the historical data; and (3) revise the decay values to test how well the monthly and cumulative annual price volatilities of the simulated prices approximate the monthly and cumulative annual price volatilities in the historical gas price data. In this Study, the decay values for CY 2010-11 were calibrated based on the average of the one and two year cumulative annual price volatilities (33.9%).

1

2 The statistical approach of minimizing the sum of residuals squared was used to help objectively
3 determine the relative merits of one set of decay values versus another. The sum of residuals
4 squared is calculated by squaring the differences between historical monthly and annual natural
5 gas price volatilities and simulated monthly and annual natural gas price volatilities and
6 summing these squared differences. The lower the sum of residuals squared, the better the
7 simulated gas price volatilities approximate the historical gas price volatilities. Table 24
8 contains the final calibration results for natural gas price volatility along with additional
9 summary statistical information.

10

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

18

19 **2.4.5.4 Model and Results**
20 Table 25 contains a copy of the Natural Gas Price Risk Model. Results from this risk model on a
21 monthly basis over time are shown in Graph 6 for the 5th, 50th, and 95th percentiles. As can be
22 noted in this graph, gas price variability started being simulated in May 2009. This was done
23 because actual historical data for January thru April of 2009 existed at the time the Risk Analysis
24 and Mitigation Study began. The monthly natural gas price variability patterns shown in this
25 graph for CY 2009-2011 reflect the computations previously calculated in Table 22, which
26 indicate that gas price volatility, in general, is highest during the winter.

27

28 The prices in Graph 6 include month-specific price level adjustments during CY 2009-CY 2011
29 that perfectly align the median monthly simulated gas prices (in real 2005$) to the monthly
30 prices in the natural gas price forecast (in real 2005$). These adjustments were made based on
31 median prices rather than average simulated prices because BPA's natural gas price forecast
32 represents its assessment that there is a 50 percent probability that natural gas prices could go
33 higher or lower than its forecast. *See* Petty, *et al.*, WP-10-E-BPA-13. Because each of these
34 monthly price level adjustments is applied to all simulated prices for that month, such
35 adjustments do not alter the simulated price volatility values.

36

37 **2.4.5.5 Use of Simulated Natural Gas Prices in AURORA$^{xmp®}$**
38 The spot market electricity price impacts associated with changes in natural gas prices are
39 estimated in AURORA$^{xmp®}$ by inputting real monthly gas price data simulated by the Natural
40 Gas Price Risk Model. From each simulation of monthly southern California natural gas prices
41 (in real 2005 dollars), annual average gas prices and monthly gas prices are derived. From this
42 data, simulated monthly and annual gas prices are derived for the zones that represent the WECC
43 region in AURORA$^{xmp®}$. This task is accomplished by adding deterministic positive/negative
44 annual average price basis differences for each of the remaining zones modeled in AURORA$^{xmp®}$
45 to the simulated monthly delivered natural gas prices for southern California to get simulated

monthly natural gas prices for all AURORA$^{xmp®}$ zones. *See* Market Price Forecast Study, WP-10-FS-BPA-03, section 3.

2.4.6   CGS Nuclear Plant Generation Risk Factor
CGS nuclear plant generation risk is incorporated into the Study to account for the impact that changes in CGS generation have on the amount of PS's surplus energy revenues and balancing power purchase expenses. CGS generation risk is modeled in the CGS Nuclear Plant Risk Model.

2.4.6.1   Data and Modeling Methodology
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, WP-10-FS-BPA-01. 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.

The calibration factor (H) is derived by running risk simulations and modifying the factor until the expected monthly CGS output from the risk simulations are equal to the expected monthly values reported in the Loads and Resources Study, WP-10-FS-BPA-01.

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 50th 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.

2.4.6.2   Model and Results
Table 26 contains a copy of the CGS Nuclear Plant Risk Model. The simulated frequency distribution for CGS output for October 2010 is shown in Graph 7.

2.4.7   Wind Resource Risk Factor
The wind resource risk factor reflects the uncertainty in the amount and value of the energy generated by PS's portion of Condon, Klondike I and III, Stateline, and Foote Creek I, II, and IV wind projects. Wind generation risk is modeled in four risk simulation models (the Foote Creek projects were combined and the Klondike projects were combined) such that the average of the simulated monthly generation outcomes for each wind project are similar to the expected

1	monthly generation included in the Loads and Resources Study, WP-10-FS-BPA-01. These four
2	risk simulation models are collectively referred to as Wind Generation Risk Models.
3	
4	The risk of the value of the wind generation is calculated in RevSim and is based on the
5	differences between the purchase prices specified in output contracts that wind generators have
6	with BPA and the wholesale electricity prices at which BPA can sell the amount of variable
7	energy produced. Under its output contracts, BPA only pays for the amount of energy that is
8	produced.
9	
10	**2.4.7.1 Historical Data**
11	To model monthly wind generation risk, daily average energy output data from March 2002 thru
12	April 2005 for Stateline, January 2002 thru April 2005 for Condon, January 2002 through April
13	2005 for Klondike I, and October 2001 through September 2004 for Foote Creek I, II, and IV
14	were sorted by month for each wind project, regardless of year. The monthly wind generation
15	risk for Klondike III was modeled based on the same data that were used for Klondike I. This
16	process yielded a minimum of three years worth of daily output data for each month of the year
17	for all projects from which cumulative probability distributions of daily output for each month
18	were derived in the RiskCumul function in the @RISK computer package.
19	
20	**2.4.7.2 Modeling Methodology for Wind Generation Risk**
21	Monthly wind generation variability for each of the wind projects (the Foote Creek projects were
22	combined and the Klondike projects were combined) was derived in risk simulation models in
23	the following manner: (1) Sample the daily wind generation values from the cumulative
24	probability distributions for each day in a given month (*i.e.*, 31 days for January); (2) Sum the
25	daily wind generation values for all days in a given month; (3) Divide the monthly sum by the
26	number of days in that particular month.
27	
28	The daily wind generation from one day to the next day was modeled independently based on the
29	highly variable daily generation amounts from one day to the next day exhibited in the historical
30	data. The output of all the wind projects were simulated independent of one another, with the
31	exception that the generation from the three Foote Creek projects and the two Klondike projects,
32	which are all on the same ridgeline, contiguously located, and electrically connected at the same
33	substation, were modeled together.
34	
35	Tables 27-30 contain copies of the cumulative probability distributions of the daily output by
36	month for each of the wind projects (with the Foote Creek projects combined and the Klondike
37	projects combined) from which daily output risk was modeled. The values in these tables are
38	specified in terms of daily capacity factors for which energy values can be computed by
39	multiplying the capacity factors times the capacity value for a particular wind project. Tables
40	31-34 contain copies of the four risk simulation models.
41	
42	**2.4.7.3 Wind Generation Risk Results**
43	The monthly generation results from the risk simulations models are in terms of flat energy.
44	Graph 8 shows the combined monthly flat energy output for all the wind projects during
45	FY 2010-2011 at the 5th, 50th, and 95th percentiles. These monthly flat energy values are input

into RevSim, where they are converted into monthly heavy and light load hour energy values by applying HLH and LLH shaping factors that are associated with each of these wind projects. The source of these HLH and LLH shaping factors is the data used to compute the monthly HLH and LLH wind generation values included under Non-Utility Generation in the Loads and Resources Study and Documentation, WP-10-FS-BPA-01 and WP-10-FS-BPA-01A.

2.4.7.4   Risk Modeling Methodology for the Value of Wind Generation

The risk of the value of the wind generation is computed in RevSim in the following manner: (1) Subtract from expenses the expected monthly payments for the expected output of the various wind projects (weighted contract prices were used for the combined Foote Creek wind projects and the combined Klondike projects); (2) On a game-by-game basis, compute the monthly payments for the output of the various wind projects; and (3) On a game-by-game basis, compute the revenues associated with the wind generation.

2.4.7.5   Value of Wind Generation Risk Results

Tables 35-36 provide information from which the value of wind generation during FY 2010-2011 can be derived for expected monthly flat energy output levels. Total deterministic wind generation purchase costs and total revenues earned from the sale of all wind generation at average, median, 5th percentile, and 95th percentile spot market electricity prices estimated by AURORA$^{xmp®}$ are provided with the value of the wind generation being the difference between the revenues earned and purchase costs paid.

2.4.8   Augmentation Cost Risk Factor

The augmentation cost risk factor reflects the uncertainty in the cost of augmentation purchases that have not been acquired prior to setting rates. The uncertainty in the cost of augmentation includes both the forecast deterministic need (aMW amount) and the electricity price risk associated with meeting that need. This risk is quantified relative to the expected augmentation costs included in the Revenue Requirement when preparing rates. *See* Revenue Requirement Study, WP-10-FS-BPA-02.

2.4.8.1   Expected Augmentation Costs for the Revenue Requirement

The expected augmentation costs included in the Revenue Requirement were calculated in RevSim by multiplying the annual average augmentation needs in FY 2010 and FY 2011 by the weighted annual average purchase prices under critical hydro conditions. *See* Revenue Requirement Study, WP-10-FS-BPA-02. The annual average augmentation needs of 476 aMW in FY 2010 and 680 aMW in FY 2011 were determined in the Loads and Resources Study, WP-10-FS-BPA-01. The weighted annual average purchase prices were derived from spot market electricity prices calculated by AURORA$^{xmp®}$ under water year 1937 hydro conditions and deterministic forecast values for PNW and California gas prices, loads, and resources (other than PNW hydro generation).

The weighted annual average price calculations were based on calculations of monthly HLH and LLH purchase costs throughout the FY. A detailed description of how these weighted annual average purchase prices were calculated is presented in Table 37 for FY 2010 and Table 38 for FY 2011 in the Study Documentation, WP-10-FS-BPA-04B.

1

2 In the calculations in these tables, HLH monthly prices (row 6) are applied to respective monthly
3 purchase amounts under critical (water year 1937) hydro conditions (row 5) to compute HLH
4 purchase expenses. A similar calculation is performed for LLH in rows 10-12. Monthly HLH
5 and LLH purchase expenses are summed to get the Total Purchase Expense (row 15) for each
6 FY. Annual HLH and LLH purchase amounts are used to calculate the annual average (flat
7 energy) purchase amount (row 16). For each FY, the annual total purchase cost (row 15) was
8 divided by the annual average purchase amount to determine the weighted annual purchase price
9 (row 17). In this calculation, the average annual purchase prices are impacted by the weighting
10 of the monthly HLH and LLH purchase amounts. Finally, the weighted annual purchase prices
11 (row 17) were applied to the Augmentation Amount (row 19) to determine the annual
12 augmentation costs (row 20).

13

14 Results of this analysis indicate that the weighted average purchase prices for FY 2010 and FY
15 2011 are $42.74/MWh and $45.48/MWh, respectively. These values are reported in Table 37,
16 row 17 and Table 38, row 17 in the Study Documentation, WP-10-FS-BPA-04B.

17

18 **2.4.8.2   Augmentation Cost for Risk Analysis**
19 For the purpose of determining augmentation cost risk in this Study, the augmentation need
20 (aMW) is divided into two categories. The first category of the augmentation need was
21 computed as though CGS was operating at the forecasted level of output in a non-planned outage
22 year for the entire rate period. This category is referred to as augmentation not due to CGS
23 planned outages (Category 1). The second category of the augmentation need was calculated as
24 the augmentation amount needed to replace the output of CGS during planned outages. This
25 category of augmentation need is referred to as augmentation need due to CGS planned outages
26 (Category 2), which is only relevant for FY 2011 in this proposal.

27

28 There are also two approaches used for determining the price risk associated with the
29 augmentation need. The first approach (Forecast 1) for determining the price risk associated
30 with the augmentation need is the same as that used for computing secondary energy and
31 balancing purchase price risk, where 3,500 games are run in AURORA by altering PNW and
32 California natural gas prices, loads, and resources. PNW hydro generation for all 70 water years
33 is used in this risk run. The methodology used to develop the prices for the second approach
34 (Forecast 2) is the same as the methodology used for the first approach with the exception of the
35 hydroelectric generation forecast. In the second approach (Forecast 2), only PNW hydroelectric
36 generation levels under 1937 hydro conditions are used for all 3,500 games per FY.

37

38 For FY 2010, which is a FY in which there are no planned CGS outages, there are only Category
39 1 augmentation needs. For FY 2010, it was assumed that 50% of the augmentation need will be
40 met at electricity prices derived under the Forecast 1 approach and the remaining 50% of the
41 augmentation need will be met at electricity prices derived under the Forecast 2 approach. For
42 FY 2011, which is a FY in which there are CGS planned outages, the total augmentation need is
43 made up of both Category 1 and Category 2 augmentation needs. For FY 2011 it was assumed
44 that 50% of the Category 1 augmentation need will be met at electricity prices derived under the
45 Forecast 1 approach, the remaining 50% of Category 1 augmentation need will be met at

1	electricity prices derived under the Forecast 2 approach, and all the Category 2 augmentation
2	need will be met at electricity prices under the Forecast 1 approach.
3	
4	RevSim calculates the total augmentation cost risk associated with each of the 3,500 games per
5	FY by summing the augmentation costs computed by these two approaches. The average
6	augmentation cost computed for the 3,500 games per FY are $171 million in FY 2010 and $264
7	million in FY 2011 (*see* Tables 39-40). A detailed description of how augmentation costs for the
8	risk analysis were calculated is provided in the next paragraph with all row references being in
9	regard to the examples provided in Tables 39 and 40, unless otherwise specified.
10	
11	In these tables, the quantities for each augmentation category are reported in rows 3 and 4 with
12	rows 9 through 21 documenting the calculation of augmentation costs using price forecast
13	method 1 and rows 25 through 41 documenting the calculation of augmentation costs using price
14	forecast method 2. The total augmentation costs are provided in row 43.
15	
16	Price forecast method 1 was applied to 50% of the Category 1 augmentation need (row 9) and to
17	all of the Category 2 augmentation need (row 10). The calculation of the average heavy-load-
18	hour augmentation costs are reported in rows 13-15 and the calculation of the average light-load-
19	hour augmentation costs are reported in rows 17-19. The average augmentation cost computed
20	using price forecast method 1 is reported in row 21.
21	
22	Price forecast method 2 was applied to 50% of the Category 1 augmentation need (row 40). The
23	average augmentation cost computed using price forecast method 2 is reported in row 41. This
24	calculation uses an annual average weighted price (row 38) applied to the annual average
25	augmentation need (row 40). The annual average weighted price was computed by first
26	computing purchase costs for heavy-load-hours (rows 25-28) and light-load-hours (rows 30-33)
27	using the respective purchase weights for these periods.
28	
29	The purchase weights used in this calculation (row 26 for HLH and row 31 for LLH) are the
30	same values as the purchase amounts for critical hydro generation from the 70-water year study
31	(refer to rows 5 and 10 in Tables 37-38 for FY 2010-2011). The total purchase cost (row 36) is
32	the sum of the HLH purchase cost (row 28) and the LLH purchase cost (row 33). These values
33	are referred to as purchase costs because they are based on the purchase weights in rows 26 and
34	31. The annual average weighted purchase price was computed by dividing the total purchase
35	cost (row 36) by the total purchases (row 37) times the hours in a year.
36	
37	The annual average weighted purchase price (row 38) was then applied to the augmentation
38	need (row 40) to determine the augmentation cost for the augmentation need that was priced
39	using price forecast method 2 (row 41). The total augmentation cost (row 43) is the sum of the
40	augmentation costs computed using price forecast method 1 (row 21) and price forecast method
41	2 (row 41).
42	
43	These calculations are performed for each FY and for each of the 3,500 iterations in the Study.
44	Summary statistics for the augmentation cost risk computed for the Study are presented in Table
45	41 in the Study Documentation, WP-10-FS-BPA-04B.

2.4.9 PS Transmission and Ancillary Services Expense Risk Factor

This risk factor reflects the uncertainty in PS transmission and ancillary services expenses, relative to the expected expenses, which average $118.5 million during FY 2010-2011, included in the Revenue Requirement when setting rates. *See* Revenue Requirement Study, WP-10-FS-BPA-02. This risk is modeled in the PS Transmission and Ancillary Services Expense Risk Model.

2.4.9.1 Data and Modeling Methodology

The modeling of this risk is based on comparisons between monthly firm transmission capacity that PS has under contract, the amount of existing firm contract sales, and the variability in surplus energy sales estimated by RevSim. Expense risk computations reflect how transmission and ancillary services expenses vary from the cost of the fixed, take-or-pay, firm transmission capacity that PS has under contract, which must be paid regardless of whether or not it is used. Because PS has more firm transmission capacity under contract than it has firm contract sales, the probability distributions for these expenses is asymmetrical since PS does not incur the costs of purchasing additional transmission capacity until the amounts of surplus energy sales exceed the amounts of residual firm transmission capacity after serving all firm sales.

Under conditions where PS sells more energy than it has firm transmission rights, transmission and ancillary services expenses will increase. Alternatively, under conditions where PS sells less energy than it has firm transmission rights, transmission expenses will remain unchanged but ancillary services expenses will decline. The methodology used in the PS Transmission and Ancillary Services Expense Model is consistent with the methodology documented in BPA's Power Function Review February 1, 2005 Technical Workshop on the Transmission Acquisition Program.

2.4.9.2 Results

Results shown in Graphs 9-10 indicate how FY 2010-2011 transmission and ancillary service expenses vary depending on the amount of surplus energy sales. In these graphs, the PS transmission and ancillary services expenses do not fall below $93 million/year, regardless of the amount of surplus energy sales, because the PS must pay for the take-or-pay firm transmission capacity it has under contract. This $93 million/year figure does not include the cost of ancillary services for any surplus energy sales, since these charges are assessed depending on the amount of transmission usage.

Results shown in Graphs 11-12 reflect the probability distributions for transmission and ancillary service expenses during FY 2010-2011. These graphs indicate how often transmission and ancillary service expenses fall within various expense ranges.

2.4.10 4(h)(10)(C) Credit Risk Factor

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 70 water years for FY 2010-2011 is determined by summing the costs of the operating impacts, the expenses, and the capital costs associated with fish and wildlife

1   mitigation measures, and then multiplying the total cost by 0.223 (22.3 percent). Of these costs,
2   only the costs of the operating impacts are variable.
3
4   The variable operating cost component of the 4(h)(10)(C) credits is calculated for each of the 70
5   water years in RevSim for FY 2010-2011 by multiplying the amounts of monthly power
6   purchases (aMWs) that qualifies for 4(h)(10)(C) credits in a given water year by the flat monthly
7   spot market electricity prices (computed from HLH and LLH spot market electricity prices
8   calculated by AURORA$^{xmp®}$) for the same water year. The amounts of power purchases (aMWs)
9   that qualifies for 4(h)(10)(C) credits is derived external to RevSim, but are used in RevSim to
10   calculate the dollar amount of the 4(h)(10)(C) credits. A description of the methodology used to
11   derive the amounts of the power purchases (aMWs) associated with the 4(h)(10)(C) credits is
12   contained in the Loads and Resources Study, WP-10-FS-BPA-01. Table 2.8.1 in the Loads and
13   Resources Study Documentation, WP-10-FS-BPA-01A, contains the 4(h)(10)(C) power purchase
14   amounts for FY 2010-2011. The expenses and capital costs associated with the 4(h)(10)(C) credit
15   are determined outside of RevSim and are input into RevSim. The capital costs are $70 million
16   for FY 2010 and $60 million for FY 2011 and the direct program expenses are $216.8 million for
17   FY 2010 and $237.8 million in FY 2011.   *See* Revenue Requirement Study, WP-10-FS-BPA-02,
18   regarding 4(h)(10)(C) expenses and capital costs. The variable operating portion of the
19   4(h)(10)(C) credit is combined with the deterministic expense and capital portions to calculate
20   the total 4(h)(10)(C) credit.
21
22   **2.4.10.1 Expected 4(h)(10)(C) Credits from the 70 Water Year Run**
23   The 4(h)(10)(C) credits used in the RAM2010 when calculating rates are derived from the 70
24   Water Year Run of RevSim (section 2.5.1 of this Study Documentation). The dollar amounts of
25   4(h)(10)(C) credits for the 70 Water Year Run of RiskMod are reported in the Revenue Forecast
26   component of the Wholesale Power Rate Development Study Documentation, WP-10-FS-
27   BPA-05A. The results from the 70 Water Year Run indicate that these credits are $97 million for
28   FY 2010 and $102 million for FY 2011.
29
30   **2.4.10.2 4(h)(10)(C) Credits from the Risk Analysis Run**
31   The 4(h)(10)(C) credits calculated for the risk analysis are computed in the same manner as the
32   4(h)(10)(C) credits computed in the 70 Water Year Run except that the results are derived from
33   the Risk Simulation Run of RevSim (section 2.5.2 of this Study Documentation), where 3,500
34   games are run under variable spot market electricity prices estimated by AURORA$^{xmp®}$ Results
35   of the 4(h)(10)(C) credits calculated for the risk analysis are shown in Graphs 13-14, which
36   report the probability distributions of the variable total 4(h)(10)(C) credits. Study
37   Documentation, WP-10-FS-BPA-04B.
38
39   **2.5   Revenue Simulation Model (RevSim)**
40   The purpose of the RevSim module within RiskMod is to determine, via simulation, Power
41   Services' operating net revenue risk. Inputs to RevSim include risk data simulated by RiskSim
42   and AURORA$^{xmp®}$ along with deterministic monthly load and resource data, monthly PF and IP
43   rates, and non-varying revenues and expenses from the Loads and Resources Study, WP-10-FS-
44   BPA-01, the Revenue Forecast component of the Wholesale Power Rate Development Study,
45   WP-10-FS-BPA-05, and the RAM2010.

1
2 RevSim uses these inputs to calculate all revenues and expenses needed to determine Power
3 Services' operating net revenues. These revenues and expenses include revenues from firm
4 power sales (including the Slice product), surplus energy sales revenues, balancing and
5 augmentation power purchase expenses, purchase expenses for wind generation, and 4(h)(10)(C)
6 credits. Additional net revenue adjustments include varying PS transmission and ancillary
7 services expenses, which are computed outside of RevSim and then input into the model. These
8 variable revenues and expenses are then combined with deterministic revenues and expenses to
9 calculate Power Services' operating net revenues.
10
11 RevSim calculates firm and surplus energy revenues and balancing and augmentation power
12 purchase costs under various load, resource, and market price conditions to estimate Power
13 Services' operating net revenue risk. A key attribute of RevSim is that it is a HLH and LLH load
14 and resource model. For each simulation, RevSim calculates Power Services' HLH and LLH
15 load and resource condition and determines HLH and LLH surplus energy sales and balancing
16 power purchases. This calculation accounts for the winter hedging purchases described in the
17 Loads and Resources Study, WP-10-FS-BPA-01, section 2.3. In those months and water years
18 where firm loads exceed resources these winter hedging purchases reduce balancing purchases.
19 Conversely, in those months and water years where resources are sufficient to serve firm loads
20 these winter hedging purchases increase the amount of surplus energy sales.
21
22 Transmission losses on BPA's transmission system are incorporated into RevSim by reducing
23 Federal hydro generation and CGS output by 2.82 percent. This factor excludes losses on the
24 Southern Intertie. This loss factor is identical to the loss factor used in the Loads and Resources
25 Study, WP-10-FS-BPA-01.
26
27 Electricity prices estimated by AURORA$^{xmp®}$ are applied to the surplus energy sales and
28 balancing power purchase amounts to determine surplus energy revenues and balancing and
29 augmentation power purchase expenses. These HLH and LLH revenues and expenses are then
30 combined with deterministic revenues and expenses to calculate Power Services' operating net
31 revenues.
32
33 RevSim is used to perform two different analyses for the ratesetting process. The first analysis is
34 referred to as the "70 Water Year Run". The 70 Water Year Run provides data to the RAM2010
35 model for calculating rates that do not include any costs associated with mitigating risk. The
36 second analysis is referred to as the "Risk Simulation Run". The Risk Simulation Run provides
37 data to the ToolKit model for the purpose of determining if BPA has met its financial objectives
38 for the rate period, and if not, what risk mitigation measures and their associated costs are needed
39 to meet these financial objectives. Both of these analyses account for the winter hedging
40 purchases.
41
42 **2.5.1   Seventy (70) Water Year Run**
43 The purpose of the 70 Water Year Run is to calculate revenues from surplus energy sales,
44 expenses associated with purchases needed to meet firm load, 4(h)(10)(C) credits and
45 augmentation purchase costs.

1

2　The risk data simulated by RiskSim for the Risk Simulation Run are not used in the 70 Water

3　Year Run of RevSim. CGS output and PS loads are provided to RevSim by repeating the

4　respective deterministic forecasted values for each of the 70 iterations. HLH and LLH spot

5　market electricity prices from the 70 Water Year Run of AURORA$^{xmp®}$, *see* Market Price

6　Forecast Study, WP-10-FS-BPA-03, section 2.5, are used to calculate surplus energy revenues

7　and balancing power purchase expenses associated with the monthly HLH and LLH surplus and

8　deficit amounts for each of the 70 water years. The average surplus energy sales amounts,

9　surplus energy sales revenues, balancing power purchase amounts, and balancing power

10　purchases expenses for the 70 water years are reported in the Revenue Forecast component of the

11　Wholesale Power Rate Development Study Documentation, Volume 1, WP-10-FS-BPA-05A.

12

13　As previously discussed in Section 2.4.10.1 of this Study Documentation, the 70 Water Year Run

14　of RiskMod calculates the annual 4(h)(10)(C) credits for inclusion into the revenue forecast

15　component of the WPRDS and RAM2010 calculation of rates. Also, as previously discussed in

16　Section 2.4.8.1 of this Study Documentation, the results for water year 1937 in the 70 Water

17　Year Run of RiskMod are used to calculate the augmentation costs for inclusion into the revenue

18　requirement, power purchase expense forecast component of the WPRDS, and RAM2010

19　calculation of rates.

20

21　**2.5.2　Risk Simulation Run**

22　The Risk Simulation Run of RevSim calculates Power Services' annual net revenues for 3,500

23　games per FY. These games use variability in Power Services' loads, resources, and

24　transmission and ancillary service expenses, in conjunction with spot market electricity prices

25　calculated by AURORA$^{xmp®}$, and 4(h)(10)(C) credits calculated by RevSim, to derive Power

26　Services' annual net revenue risk. Non-Slice PF load variability, which is derived from PNW

27　load variability, is quantified as ratios relative to 1.00. These load variability ratios are

28　multiplied by the forecasted monthly PF loads subject to the load variance charge (*see* Loads and

29　Resources Study, WP-10-FS-BPA-01). The differences between the simulated and forecasted

30　values are added to the forecasted monthly non-Slice PF loads reported in the Loads and

31　Resources Study, WP-10-FS-BPA-01, to obtain variable non-Slice PF loads**.**

32

33　These variable non-Slice PF loads are multiplied by the PF rate to obtain variable non-Slice PF

34　energy revenues. In addition to adjusting non-Slice PF loads (energy), the ratios (relative to

35　1.00) are multiplied by the forecasted monthly PF demand in the Revenue Forecast component

36　of the Wholesale Power Rate Development Study, WP-10-FS-BPA-05, to obtain variable PF

37　demand. These variable demand values are multiplied by the PF demand charge to obtain

38　variable non-Slice PF demand revenues.

39

40　Surplus energy revenues and balancing power purchase expenses are based on Federal hydro

41　generation (70 water years) adjusted to account for refilling non-treaty storage in Canada and

42　efficiency losses associated with standing ready to provide and deploy within-hour balancing

43　reserves, Federal HLH hydro generation ratios (70 water years), BPA load variability, CGS

44　output variability, variable wind generation, and AURORA$^{xmp®}$ spot market electricity prices.

45　RevSim calculates monthly HLH and LLH surplus energy sales and balancing power purchases

|	
1	and applies corresponding HLH and LLH prices estimated by AURORA$^{xmp®}$ to determine
2	surplus energy sales revenues and balancing power purchase expenses.
3	
4	The differences in the 4(h)(10)(C) credits between the 70 Water Year Run and the Risk
5	Simulation Run are based on the differences in the spot market electricity prices estimated by
6	AURORA$^{xmp®}$ for the 70 Water Year Run and the Risk Simulation Run. Augmentation cost risk
7	is modeled by replacing the deterministic augmentation costs computed from the 70 Water Year
8	Run with the augmentation costs computed under the methodology described in section 2.4.8.2
9	of this Study Documentation.
10	
11	**2.5.3 Data Management Procedures (DMPs)**
12	RiskMod receives data from a variety of sources and provides data to other computer models
13	used in the rates process including AURORA$^{xmp®}$, RAM2010, and ToolKit. Data are stored in
14	two ACCESS databases, the Risk Input Database and the Risk Output Database. Figure 1
15	depicts a typical Risk Input Database and Figure 2 depicts a typical Risk Output Database. The
16	computer applications used to move data between modules within RiskMod (*i.e.*, RiskSim,
17	RevSim, and the Risk input and output databases) and also between RiskMod and other
18	computer models are collectively referred to as Data Management Procedures (DMPs).
19	
20	
21	**Figure 1: Typical Risk Input Database shown in Microsoft Access**
22	
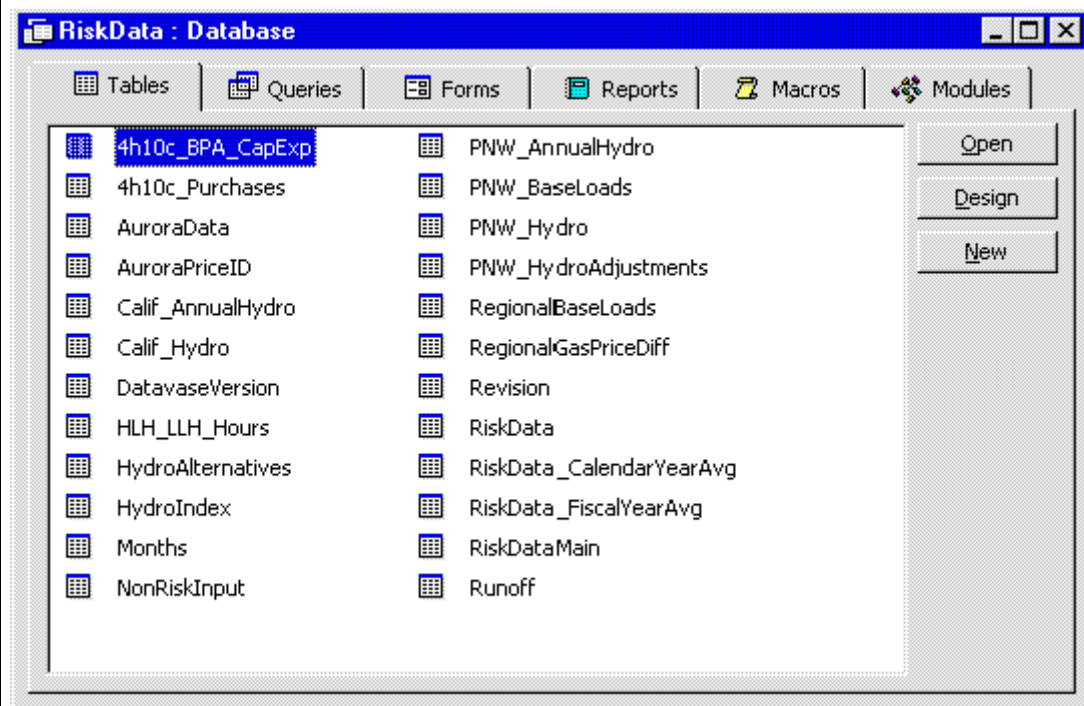
Figure 2: Typical Risk Output Database shown in Microsoft Access
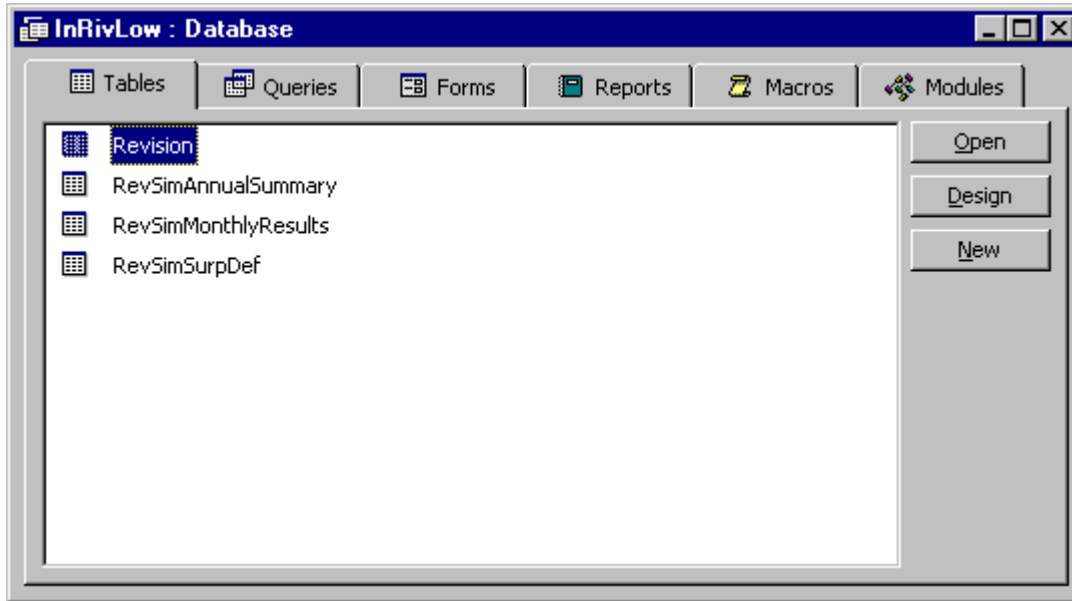
2.5.3.1   DMPs For Deterministic Data

Deterministic data from the Loads and Resources Study, WP-10-FS-BPA-01, are stored in the Risk Input Database and then read from the database by automated procedures within RevSim. Non-varying revenues, expenses, monthly rates, and the factor for estimating transmission losses are manually input directly into RevSim.

2.5.3.2   DMPs For Hydro Generation Data

Federal hydro generation data from the Loads and Resources Study, WP-10-FS-BPA-01, are downloaded as flat energy and HLH energy generation for each of the 70 water years. These data are used to calculate Federal HLH hydro generation ratios for each of the 70 water years. The flat generation values and HLH ratios are loaded into the Risk Input Database using the Data Manager computer application, which is one of the Data Management Procedures previously discussed.

The adjustments to Federal hydro generation associated with refilling non-treaty storage in Canada and adjustments to account for efficiency losses associated with standing ready to provide and deploy within-hour balancing reserves are not included in the Loads and Resources Study, WP-10-FS-BPA-01, and were received in Excel workbooks. These adjustments are added to Federal generation values as part of the process of loading hydro generation data into the Risk Input Database.

2.5.3.3   DMPs For Risk Data

Risk data simulated by RiskSim are loaded into the Risk Input Database using the Data Manager computer application.

2.5.3.4   DMPs for Interaction with AURORA$^{xmp®}$

AURORA$^{xmp®}$ reads data from an input SQL database and writes results to an output SQL database and excel workbook. To process multiple sets of simulated values, the software's internal feature known as a computational dataset table is used. The computational dataset table allows users to dynamically change input data in AURORA$^{xmp®}$'s input database tables. To process multiple simulations, multiple study cases are processed in AURORA$^{xmp®}$.

AURORA$^{xmp®}$ uses calendar year (CY) data rather than fiscal year (FY) data. The rate case period (FY 2010-2011) starts in October of CY 2009 and ends in September of CY 2011. In order to obtain prices that cover the rate case period, it is necessary to provide AURORA$^{xmp®}$ with three CY of data, *i.e.,* January 2009 through December 2011.

2.5.3.4.1   AURORA$^{xmp®}$ Seventy (70) Water Year Run

The only data varied in the 70 Water Year Run of AURORA$^{xmp®}$ is PNW hydro generation (*see* Hydroregulation component of the Loads and Resources Study, WP-10-FS-BPA-01), which is reported in Tables 1-2 of this Study Documentation. Data are supplied to AURORA$^{xmp®}$ as twelve monthly energy "ratios" along with a 13th value, which is the annual average hydro generation energy to capacity factor. The monthly hydro generation ratios supplied to AURORA$^{xmp®}$ are computed in 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 70 water years. The annual energy to capacity factor is calculated by dividing the PNW annual average hydro generation for each of the 70 water years (*see* Loads and Resources Study, WP-10-FS-BPA-01) by the PNW hydro capacity used in AURORA$^{xmp®}$ (*see* Market Price Forecast Study, WP-10-FS-BPA-03).

The data computed in the Excel workbook is imported into AURORA$^{xmp®}$ as a table in the table type category called "unknown". A computational dataset table for each calendar year is used to change the PNW hydro generation for each simulation. The AURORA$^{xmp®}$ project file contains 70 study cases, which completes the 70 simulations – one simulation for each water year. Upon completion of the 70 simulations, monthly HLH and LLH spot market electricity prices for FY 2010-2011 for each of the 70 water years are exported to an excel workbook. The Data Manager loads this Excel workbook into the Risk Input Database.

2.5.3.4.2   AURORA$^{xmp®}$ Risk Simulation Run

For the Risk Simulation Run of AURORA$^{xmp®}$, variation in natural gas prices, PNW and California loads, and PNW and California hydro generation are accounted for. *See* Market Price Forecast Study, WP-10-FS-BPA-03. AURORA$^{xmp®}$ is used to estimate HLH and LLH spot market electricity prices for 3,500 simulations. Considering the large number of simulated values produced in a Risk Simulation Run, the volume of data could not be reasonably loaded into a single workbook, as is done for the 70 Water Year Run. The simulated values are divided by data type (e.g., PNW load, California load, and natural gas price) and calendar year. For each data type and calendar year, a unique Excel worksheet is imported into AURORA$^{xmp®}$ as a table in the table type category called "unknown".

The modeling process for the Risk Simulation Run of AURORA$^{xmp®}$ is similar to that used for a
70 Water Year Run of AURORA$^{xmp®}$. A computational dataset table for each calendar year and
data type is used to change the simulated values for each simulation. The AURORA$^{xmp®}$ project
file contains 3,500 study cases, which completes the 3,500 simulations. Upon completion of the
3,500 simulations, monthly HLH and LLH spot market electricity prices for FY 2010-2011 for
each of the 70 water years are exported to an Excel workbook. The Data Manager loads this
Excel workbook into the Risk Input Database.

2.5.3.5   DMPs For RevSim

The net revenue simulations in RevSim combine variable data from the Risk Input Database with
deterministic data that are directly input. Code within RevSim reads the data from the Risk Input
Database, activates the calculation within RevSim, and writes results to the Risk Output
Database. The computer code contained in these procedures is comprised of a combination of
Microsoft Visual Basic and Structured Query Language.

The procedures in RevSim perform the study one iteration at a time, *i.e.*, 70 iterations for the
70 Water Year Run and 3500 iterations for the Risk Simulation Run. For each iteration, data are
read which reflect the variability in non-Slice PF loads, the output of CGS, variable wind
generation, PS transmission and ancillary services expenses, Federal hydro generation, Federal
hydro generation HLH ratios, 4(h)(10)(c) power purchase amounts, and the HLH and LLH spot
market electricity prices from AURORA$^{xmp®}$. Using these data, surplus energy sales and
balancing power purchase amounts (aMW), surplus energy revenues and balancing power
purchase expenses, 4(h)(10)(C) credits, and PBL net revenues are calculated and written to the
Risk Output Database. The Risk Output Database contains both monthly and annual summary
data for many of the quantities calculated.

2.5.3.6   DMPs Between RiskMod, RAM2010, and ToolKit

Data transfers between these models are generally accomplished through Excel files or as
manual data entry. Surplus energy revenues, balancing power purchase expenses, and
4(h)(10)(C) credits are provided to RAM2010 as an Excel workbook generated from the Risk
Output Database. *See* Wholesale Power Rate Development Study, WP-10-FS-BPA-05,
regarding RAM2010. Rates from RAM2010 are manually entered into RevSim from a
RAM2010 summary file. Annual net revenues are provided from RiskMod to ToolKit as an
Excel workbook generated from the Risk Output Database. There is no automated procedure for
communicating the value of PNRR from ToolKit to RAM2010.

2.5.4   Interaction Between RiskMod, RAM2010, and ToolKit

RiskMod is used in an iterative process with the RAM2010 and ToolKit Model to calculate rates,
PNRR, and to design other financial tools as needed (*i.e.*, surcharges or credits) to assure BPA
will achieve its financial objectives for the rate period. The initial step in the process is to
estimate the annual average surplus energy revenues, balancing power purchase expenses, and
4(h)(10)(C) credits in the 70 Water Year Run of RiskMod and input these data into RAM2010.
With this information, RAM2010 calculates an initial set of rates for the rate period which is fed
back to RevSim. RevSim is run and produces 3500 net revenues for each FY in the rate period.

1	These results are input into ToolKit to calculate the amount of PNRR and other financial tools
2	needed to achieve BPA's financial objectives.
3	
4	**2.5.5 Results from RiskMod**
5	A statistical summary of the annual net revenues for FY 2010-2011 estimated by RiskMod using
6	Proposed Rates with $0 million in PNRR is reported in Study Documentation, WP-10-FS-BPA-
7	04B, Table 42. Net revenues over the rate period averaged $64.5 million/year. These values
8	represent only the operating net revenues calculated in RiskMod. They do not reflect additional
9	net revenue adjustments in the ToolKit model due to the output from NORM, interest earned on
10	financial reserves, and the impacts of the CRAC and DDC. Also, the average net revenues in
11	Table 42 will differ from the net revenues shown in the Revenue Requirement Study, WP-10-FS-
12	BPA-02, Table 1, because Table 1 shows the results of a deterministic forecast that does not
13	account for the impact of risks.
14	

1   **3.   NON-OPERATING RISK ANALYSIS MODEL (NORM)**
2

3   **3.1   Methodology**
4   NORM is written in Excel 2003 with the @RISK add-in package. Each of the risks is modeled
5   using probability functions available in @RISK. Some of these functions are *discrete* while
6   others are *continuous*. Discrete functions take two arrays as inputs, one listing the possible
7   values the uncertain variable can take, the other the respective probabilities of those values. In
8   other words, for an uncertainty having to do with expense levels, the input consists of a series of
9   dollar amounts by which the expense level in the revenue requirement could vary, and the
10   probability, as a percentage, that each amount of variation could occur.
11

12   For example, when rolling dice, the operation of a single die would be described as follows
13   (fractions rounded off):
14

15   <die> =RiskDiscrete(A1:F1,A2:F2)
16

17   with the values 1, 2, 3, 4, 5, and 6 in cells A1 to F1, and identical probabilities of 17 percent in
18   each of the cells A2 to F2. When @RISK is run, each game will have a value for the function
19   drawn randomly from the set of six possible values according to those probabilities. If
20   1,000 games are run, there should be about 167 games (1,000 / 6) where the value is 1, and about
21   the same number with each of the other values. The actual number may vary slightly, but
22   probably not by much. The larger the number of games, the more closely the actual count is
23   likely to approach the expected number, which equals the probability times the number of games.
24

25   Since NORM is used to represent the possibilities that actual values for various factors will be
26   different from the deterministic value used as starting points in the rate case calculations, this
27   example will illustrate NORM better with one change. Assume that the expected value of the
28   roll of the die, 3.5, has been used in the revenue requirement. Then the actual NORM
29   distribution would comprise the six possible values shown above, while the output from NORM
30   used in the ToolKit would comprise the six deviations from the expected value, or 2.5, 1.5, .5,
31   -.5, -1.5, and -2.5.
32

33   Each risk modeled in NORM is described by a *model* and enough data to *specify* the model. A
34   model could be as simple as the discrete risk example above of a single die, or it could be a
35   complicated formula with many random factors in it, each of which uses a different probability
36   distribution. A simple model's specification might require only a few numbers; a complex
37   model might require specifying several distributions (identifying the distributions and giving the
38   parameters) as well as the functional relationships among the various distributions.
39

40   Some distributions in NORM are continuous probability distributions, such as the Normal
41   probability distribution. For these, the *parameters* of the distribution of possible deviations are
42   entered (*e.g.*, mean and standard deviation for the Normal distribution). For example, the
43   Consumer Price Index (CPI) is a factor in the calculation of payments under the Colville/
44   Spokane Settlement. The future values of the CPI cannot be known now, but are modeled in
45   NORM. For calculating the FY 2010 Colville/Spokane Settlement payments, the annual change

in the CPI is modeled as a Normal distribution with a mean of 2.0 percent and a standard
deviation of 0.5 percent. In each game, @Risk produces a number for the annual change in CPI
in such a way that the set of results from all of the games approximates a Normal distribution,
that is, @Risk "draws" a number from a Normal distribution with mean of 2.0 percent and
standard deviation of 0.5 percent. This set of results will approximate a Normal distribution
more and more closely as the number of games increases.

Deviations are expressed in annual average amounts. Negative amounts indicate a decrease in
net revenues, *i.e.*, either a decrease in revenue or an increase in expense. Positive amounts
indicate an increase in net revenues, *i.e.*, either an increase in revenue or a decrease in expense.
BPA developed the distributions of the risks (possible values and associated probabilities). For
instance, the probabilities that a line item will deviate from the costs included in the revenue
requirement could be distributed as follows:

- 40 percent probability that costs will deviate $0 (in other words, a 40 percent probability
  that they will be the same as the level projected in the revenue requirement)

- 20 percent probability that costs will be $10 M higher (shown as -$10 M in NORM
  output)

- 20 percent probability that costs will be $10 M lower (shown as $10 M in NORM output)

- 10 percent probability that costs will be $25 M higher

- 10 percent probability that costs will be $25 M lower

NORM models the risks of Power Services, as well as the risks of the Corporate costs which are
the responsibility of Power Services. Transmission Services risks are not included in the
analysis. In general, NORM includes the Power Services expense uncertainty due to the rates
yet to be developed for transmission services. The impacts of Transmission Services revenue
uncertainty on BPA's financial picture are excluded. NORM does model some changes in
revenue, and some changes in cash. Many of the expense risks are included in the Slice true-up,
so NORM models the change in the Slice true-up that would be implied by a change in these
expense items, which could result in an increase in revenue if the Slice true-up is positive for
BPA. A NORM deviation of -$10M subject to the Slice true-up is handled in this way: In year
N, the increase of $10M in expense is noted. $2.26M of this will be covered by the Slice true-up
booked in that same year, so NORM notes an increase in net revenue of $2.26M, partially
offsetting that expense increase. In that same year N, cash is decreased by the full $10M, but the
payment by the Slice customers (or a reduction in payment by BPA to the Slice customers) of
$2.26M in the year following year N is also noted.

The distributions for each expense and revenue item modeled in NORM are shown in Study
Documentation, WP-10-FS-BPA-04B, section 3. The values in the probability distribution
graphs are in millions of dollars and the statistical data accompanying those graphs are in

1 thousands of dollars. (The deviations are calculated by comparing the values in the distributions
2 to the point values assumed elsewhere in the rate case (*e.g.*, the revenue requirement).)
3

1 **4.   RISK MITIGATION**
2
3 There is no additional risk mitigation discussion. Study Documentation, WP-10-FS-BPA-04B
4 reports the TK Main worksheet.
5
6
7