B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

2007 Supplemental Wholesale Power Rate Case
Final Proposal

FY 2009 RISK ANALYSIS STUDY DOCUMENTATION

September 2008

WP-07-FS-BPA-12A

RISK ANALYSIS STUDY DOCUMENTATION
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COMMONLY USED ACRONYMS

AC	Alternating Current
AEP	American Electric Power Company, Inc.
AER	Actual Energy Regulation
AFUDC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
Alcoa	Alcoa Inc.
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
AOP	Assured Operating Plan
ASC	Average System Cost
Avista	Avista Corporation
BASC	BPA Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
C&R Discount	Conservation and Renewables Discount
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAC	Columbia Falls Aluminum Company
Cfs	Cubic feet per second
CGS	Columbia Generating Station
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
Con Aug	Conservation Augmentation
C/M	Consumers / Mile of Line for Low Density Discount
ConMod	Conservation Modernization Program
COSA	Cost of Service Analysis
Council	Northwest Power Planning 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
CT	Combustion Turbine
CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones
DOE	Department of Energy
DOP	Debt Optimization Program
DROD	Draft Record of Decision

DSI	Direct Service Industrial Customer or Direct Service Industry
ECC	Energy Content Curve
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
EQR	Electric Quarterly Report
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FERC SR	Federal Energy Regulatory Commission Special Rule
FELCC	Firm Energy Load Carrying Capability
Fifth Power Plan	Council's Fifth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
GCPs	General Contract Provisions
GEP	Green Energy Premium
GI	Generation Integration
GSR	Generation Supplied Reactive and Voltage Control
GRI	Gas Research Institute
GRSPs	General Rate Schedule Provisions
GSP	Generation System Peak
GSU	Generator Step-Up Transformers
GTA	General Transfer Agreement
GWh	Gigawatt-hour
HLH	Heavy Load Hour
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU	Investor-Owned Utility
IP	Industrial Firm Power (rate)
IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company
ISO	Independent System Operator
JP	Joint Party

JP1	Cowlitz County Public Utility District, Northwest Requirements Utilities and Members, Western Public Agencies Group and Members, Public Power Council, Industrial Customers of Northwest Utilities
JP2	Grant County Public Utility District No. 2, Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Western Public Agencies Group and Members(Grays Harbor)
JP3	Benton County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, Western Public Agencies Group and Members (Grays Harbor)
JP4	Cowlitz County Public Utility District, Eugene Water & Electric Board, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, Grant County Public Utility District No. 2
JP5	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma, specified members of WA[1]
JP6	Avista Corporation, Idaho Power Corporation, PacifiCorp, Portland General Electric Company, Puget Sound Energy, Inc.
JP7	NONE
JP8	Northwest Energy Coalition, Save Our *Wild* Salmon
JP9	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members, PacifiCorp, Western Public Agencies Group and Members, Avista Corporation, Portland General Electric Company

[1] The members of Western Public Agencies Group and Members (WA) that are participating in the JP5 designation include: Benton REA, the cities of Ellensburg and Milton, the towns of Eatonville and Steilacoom, Washington, Alder Mutual Light Co., Elmhurst Mutual Power and Light Co., Lakeview Light and Power Co., Parkland Light and Water Co., Peninsula Light Co., the Public Utility Districts of Grays Harbor, Kittitas, Lewis and Mason Counties, the Public Utility District No. 3 of Mason County, and the Public Utility District No. 2 of Pacific County, Washington.

JP10	Alcoa, Inc., Cowlitz County Public Utility District, Industrial Customers of Northwest Utilities
JP11	Cowlitz County Public Utility District, Eugene Water & Electric Board, Grant County Public Utilities District No. 2, Pacific Northwest Generating Cooperative and Members, Pend Oreille County Public Utility District No. 1, Seattle City Light, City of Tacoma
JP12	Alcoa, Inc., Industrial Customers of Northwest Utilities, Public Power Council, Western Public Agencies Group and Members, Northwest Requirements Utilities and Members, Pacific Northwest Generating Cooperative and Members
JP13	Columbia River Inter-Tribal Fish Commission, Confederated Tribes and Bands of the Yakama Nation, Nez Perce Tribe
JP14	Benton County Public Utility District, Cowlitz County Public Utility District, Eugene Water & Electric Board, Franklin County Public Utility District No. 1, Grant County Public Utilities District No. 2, Industrial Customers of Northwest Utilities, Northwest Requirements Utilities and Members , Public Power Council, Seattle City Light, City of Tacoma, Western Public Agencies Group and Members, Springfield Utility Board, Pacific Northwest Generating Cooperative and Members
JP15	Calpine Corporation, Northwest Independent Power Producers Coalition, PPM Energy, Inc., TransAlta Centralia Generation, LLC
kAf	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LOLP	Loss of Load Probability
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAf	Million Acre Feet
MCA	Marginal Cost Analysis
Mid-C	Mid-Columbia
MIP	Minimum Irrigation Pool
MMBTUMMBtu	Million British Thermal Units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool

MORC	Minimum Operating Reliability Criteria
MT	Market Transmission (rate)
MVAr	Mega Volt Ampere Reactive
MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand
NWEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NF	Nonfirm Energy (rate)
NFB Adjustment	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) Adjustment
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPA	Northwest Power Act
NPCC	Northwest Power and Conservation Council
NPV	Net Present Value
NR	New Resource
NR (rate)	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
OATT	Open Access Transmission Tariff
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PBL	Power Business Line
PDP	Proportional Draft Points
PF	Priority Firm Power (rate)
PFR	Power Function Review
PGE	Portland General Electric Company
PGP	Public Generating Pool
PMA	Power Marketing Agencies

PNCA	Pacific Northwest Coordination Agreement
PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point Transmission
PUD	Public or People's Utility District
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
RD	Regional Dialogue
REP	Residential Exchange Program
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTO	Regional Transmission Operator
SCCT	Single-Cycle Combustion Turbine
Slice	Slice of the System (product)
SME	Subject Matter Expert
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
SOS	Save Our *Wild* Salmon
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TBL	Transmission Business Line
Tcf	Trillion Cubic Feet
TPP	Treasury Payment Probability
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
Tribes	Columbia River Inter-Tribal Fish Commission, Nez Perce, Yakama Nation, collectively

UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council (formally called WSCC)
WMG&T	Western Montana Electric Generating and Transmission Cooperative
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSCC	Western Systems Coordination Council (now WECC)
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
Yakama	Confederated Tribes and Bands of the Yakama Nation

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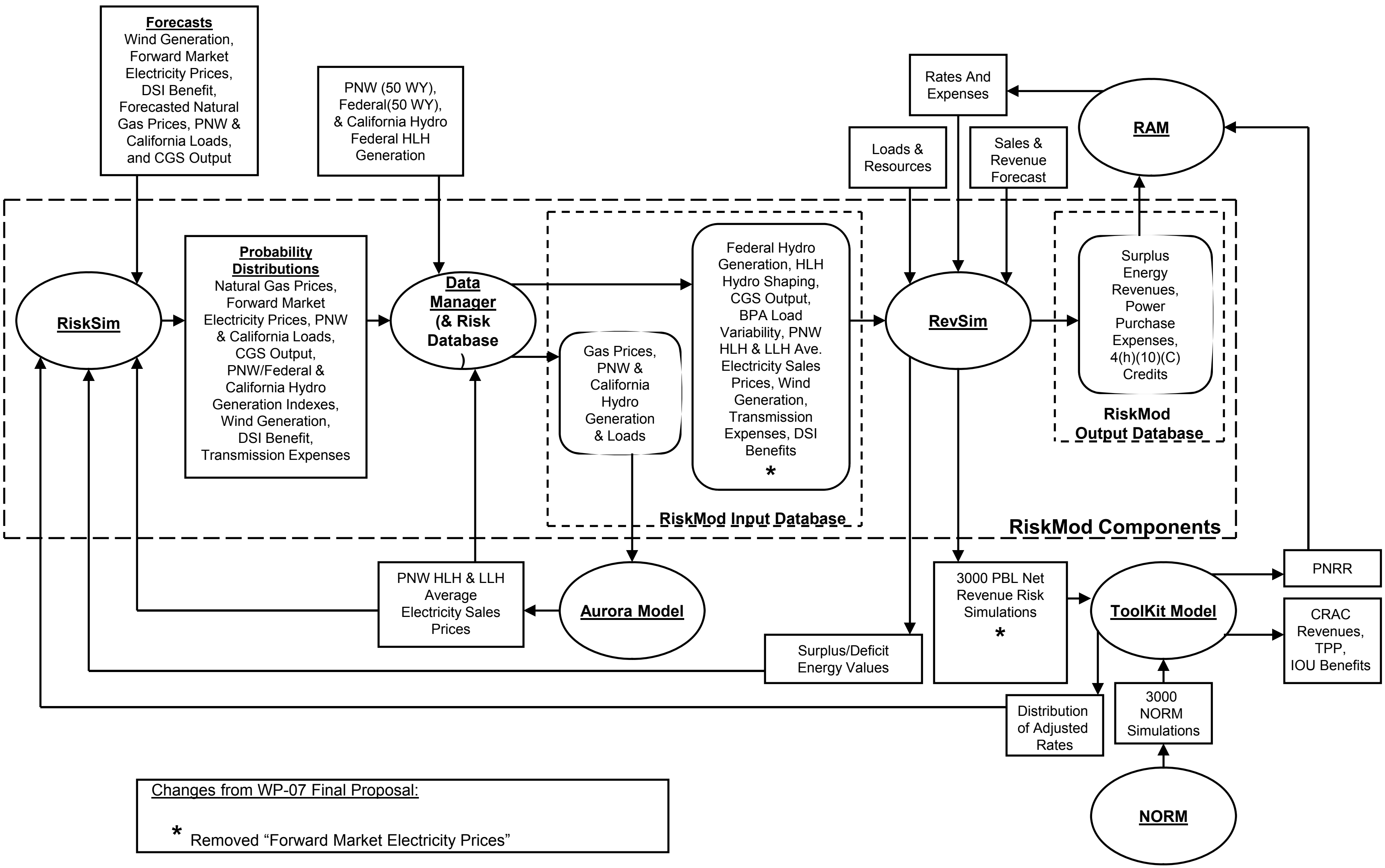
1. OPERATIONAL RISK ANALYSIS MODEL (RISKMOD)

1.1 RiskMod

The RiskMod Model is comprised of a set of risk simulation models, collectively referred to as RiskSim; a set of computer programs that manages data referred to as Data Management Procedures; and RevSim, a model that calculates net revenues. RiskMod interacts with the AURORA Model, the RAM2007, and the ToolKit Model during the process of performing the Risk Analysis Study. AURORA is the computer model being used to perform the Market Price Forecast Study (*see* FY 2009 Market Price Forecast Study, WP-07-FS-BPA-11; the RAM2007 is the computer model being used to calculate rates (*see* FY 2009 Wholesale Power Rate Development Study, WP-07-FS-BPA-13); and the ToolKit is the computer model being used to develop the risk mitigation package that achieves BPA's 97.5 percent TPP standard (*see* Section 3 in the FY 2009 Risk Analysis Study, WP-07-FS-BPA-12).

Variations in monthly loads, resources, natural gas prices, forward market electricity prices, and aluminum smelter benefit payments are simulated in RiskSim. Monthly spot market electricity prices for the simulated loads, resources, and natural gas prices are estimated by the AURORA Model. Data Management Procedures facilitate the format and movement of data that flow to and/or from RiskSim, AURORA, and RevSim. RevSim estimates net revenues using risk data from RiskSim, spot market electricity prices from AURORA, loads and resources data from the FY 2009 Load Resource Study, WP-07-FS-BPA-09, various revenues from the Revenue Forecast component of the FY 2009 Wholesale Power Rate Development Study, WP-07-FS-BPA-13, and rates and expenses from the RAM2007. Annual average surplus energy revenues, purchased power expenses, and section 4(h)(10)(C) credits calculated by RevSim are used in the Revenue Forecast and the RAM2007. Surplus energy values from RevSim are used in the Transmission Expense Risk Model to calculate variable transmission expenses. Net revenues estimated for each simulation by RevSim are input into the ToolKit Model to develop the risk mitigation package that achieves BPA's 97.5 percent TPP standard. The processes and interaction between each of the models and studies are depicted in Graph 1.

Graph 1: RiskMod Risk Analysis Information Flow



1.2 Risk Simulation Models (RiskSim)

To quantify the effects of operational risks, BPA developed risk models that combine the use of logic, econometrics, and probability distributions to quantify the ordinary operational risks that BPA faces. Econometric modeling techniques are used to capture the dependency of values through time. Parameters for the probability distributions were developed from historical data. The values sampled from each probability distribution reflect their relative likelihood of occurrence and are deviations from the base case values used in the Revenue Forecast, Revenue Requirement, and AURORA Model. (*See* the Revenue Forecast component of the FY 2009 Wholesale Power Rate Development Study, WP-07-FS-BPA-13; the FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10; and discussion of the AURORA Model in the FY 2009 Market Price Forecast Study, WP-7-FS-BPA-11).

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 the AURORA Model. *Id*. Loads, resources, and natural gas price risk data for each simulation are input into the AURORA Model to estimate monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) spot market electricity prices. The prices estimated by AURORA 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.

For the WP-07 Final Supplemental Proposal, most of the risk models contained in RiskSim were updated from the WP-07 Initial Supplemental Proposal using revised data for FY 2008-2009. The exceptions are that data in the Wind Generation Risk Models were not modified. Also, unlike in the WP-07 Initial Supplemental Proposal, simulated forward market price risk data for a 12-month strip of power for FY 2009 (simulated by the Forward Market Price Risk Model) were not used in the WP-07 Final Supplemental Proposal when computing DSI Benefit risk. *See* Section 1.15 of this Study Documentation, regarding why the Forward Market Price Risk Model was not run for FY 2009 in the WP-07 Final Supplemental Proposal. Similarly, annual average flat PF rate risk data (due to either a CRAC or DDC being triggered for FY 2009 depending on FY 2008 financial results) for FY 2009 (calculated by the ToolKit Model) were not used when computing DSI Benefit risk in the WP-07 Final Supplemental Proposal. *See* Section 1.12.1 of this Study Documentation, regarding why variable PF rates for FY 2009 were not computed in the ToolKit Model for the WP-07 Final Supplemental Proposal.

The Supplemental Proposal uses the same methodology for calculating net revenues (RevSim) as was used in the WP-07 Final Proposal with data updates for FY 2008-2009. Data which were updated for FY 2009 are noted in the discussion of operational risk factors which follows in Sections 1.5 through 1.15. Net revenues for FY 2008 were determined using actual revenues and expenses for October 1, 2007 through July 31, 2008 and an assessment of the uncertainty in revenues and expenses for August and September 2008.

1.3 @RISK Computer Software

Most of the risk simulation models developed to quantify operational 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.

1.4 Operational Risk Factors

In the course of doing business, BPA manages risks that are unique to operating a hydro system as large as the FCRPS. The variation in hydro generation due to the volume of water supply from one year to the next can be substantial. BPA also faces other operational risks that increase BPA's risk exposure, including the following: (1) load variability due to changes in load growth and weather; (2) nuclear plant (CGS) generation; (3) wind generation and value of output; (4) transmission expenses; (5) DSI payment benefits; and (6) variability in electricity prices due to load, resource, and natural gas price variability. All these risk factors are quantified in the Risk Analysis Study.

The following is a discussion of the major risk factors included in RiskMod. Each of these risk factors is used in the AURORA Model, RevSim, or both.

1.5 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 Risk Analysis Study to account for the impact that various PNW hydro generation levels have on monthly HLH and LLH spot market electricity prices estimated by the AURORA Model.

1.5.1 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 50 water years from the Hydroregulation component of the Load Resource Study. These hydro generation data for FY 2009 were revised since the WP-07 Initial Supplemental Proposal. (*See* FY 2009 Load Resource Study, WP-07-FS-BPA-09, regarding 50 water years.) The monthly hydro generation data for each of the 50 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 50 water years (1929-1978). (*See* FY 2009 Load Resource Study, WP-07-FS-BPA-09, regarding HydroSim.)

A consistent set of monthly Federal and PNW hydro generation data for hydro operations are randomly sampled, by water year, from tables containing hydro generation values for each of the 50 water years for 12 months of the year (50 X 12 tables). The 50 x 12 tables were derived from 50 x 14 tables by averaging hydro generation data for the first and second half of April and August. The ability of the FCRPS to shape average monthly hydro generation into HLH hydro generation, for each water year, is incorporated into RiskMod by selecting from a 50 x 12 table of HLH hydro generation ratios produced from a comparable run of the Hourly Operating and Scheduling Simulator (HOSS) Model. (*See* Fy 2009 Load Resource Study, WP-07-FS-BPA-09.) 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 from HOSS, LLH ratios are calculated in RevSim. Tables 3 and 6 contain the 50 x 12 tables of PNW and Federal hydro generation data for FY 2009. Similarly, Table 9 contains the 50 x 12 table of HLH ratios from HOSS for FY 2009.

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 FY 2009 Load Resource Study, WP-07-FS-BPA-09, regarding a continuous study by HydroSim. The term "continuous study" refers to calculating hydro generation data sequentially over all 600 months of the 50 water year period. Developing hydro generation data in such a continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 50 water year period.

Table 1: PNW Hydro Generation (aMW) with Hydro Independents for FY 2007

(This table is not applicable to the WP-07 Final Supplemental Proposal)

Table 2: PNW Hydro Generation (aMW) with Hydro Independents for FY 2008

(This table is not applicable to the WP-07 Final Supplemental Proposal)

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929												
1930												
1931												
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Table 3: PNW Hydro Generation (aMW) with Hydro Independents for FY 2009

(Updated from WP-07 Initial Supplemental Proposal)

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	10,016	11,805	12,291	11,309	9,162	11,283	8,918	10,482	16,298	12,918	9,634	8,873
1930	10,431	11,786	12,157	9,137	11,044	9,709	10,428	10,813	14,365	12,933	9,444	9,055
1931	10,163	11,846	12,116	9,651	9,002	9,714	9,702	10,338	14,823	12,654	10,130	9,580
1932	9,450	11,348	11,745	9,874	9,468	12,622	17,404	20,294	18,191	14,101	10,514	9,808
1933	10,434	11,901	13,038	19,201	15,753	12,088	14,526	16,964	18,073	17,084	13,885	10,832
1934	12,319	15,429	19,758	20,198	19,461	18,264	17,994	18,409	16,338	13,180	9,072	9,033
1935	10,510	12,161	11,810	18,040	18,767	10,469	13,094	17,007	15,445	15,585	11,684	9,146
1936	10,292	11,873	11,999	10,171	10,043	11,493	13,491	19,132	18,049	12,389	10,410	8,467
1937	10,226	11,710	12,467	9,463	9,348	9,631	9,846	11,132	15,217	11,808	10,804	9,091
1938	10,250	11,961	12,742	18,365	14,440	14,893	17,168	20,411	17,844	14,478	9,709	9,736
1939	10,541	11,644	11,591	13,063	10,047	11,566	14,360	18,607	14,103	12,358	8,819	8,273
1940	10,622	11,621	13,480	11,761	12,291	16,237	15,399	15,069	15,208	11,208	8,570	9,034
1941	10,251	11,270	12,545	13,121	10,360	12,011	9,635	10,016	14,954	12,201	9,936	10,218
1942	9,563	11,011	14,269	16,777	12,397	8,588	12,608	14,708	18,321	16,182	11,623	9,431
1943	10,645	11,949	12,508	17,309	17,091	15,769	18,535	19,992	18,373	16,342	11,377	8,680
1944	9,879	11,768	12,317	12,166	9,315	9,100	8,715	10,736	14,035	10,894	9,500	9,582
1945	9,349	11,035	11,190	9,725	10,191	9,274	8,373	15,411	18,257	11,554	9,713	8,775
1946	9,970	11,979	13,275	16,133	14,184	16,461	17,873	20,733	18,092	16,493	11,423	9,759
1947	10,248	12,041	17,489	18,764	18,819	18,177	16,080	19,118	18,215	16,076	10,844	9,543
1948	14,629	14,801	15,654	20,025	14,862	14,167	16,172	20,657	18,432	17,153	13,865	10,716
1949	11,225	12,044	12,745	13,671	12,900	16,898	17,452	20,708	18,096	11,761	9,372	8,115
1950	10,236	11,854	12,642	17,849	18,534	19,530	18,102	18,952	17,775	17,324	12,844	10,118
1951	12,544	14,510	19,341	20,420	19,909	19,450	18,420	20,518	18,208	17,146	12,515	9,688
1952	13,617	12,701	15,770	20,196	16,452	12,882	18,293	20,811	18,418	15,110	10,856	8,830
1953	10,213	11,632	11,641	13,237	18,145	12,881	11,857	18,585	18,439	17,320	11,772	9,558
1954	11,201	12,076	14,459	17,294	19,565	14,799	15,662	19,692	17,956	17,240	16,334	13,868
1955	11,392	13,061	14,975	12,907	11,602	11,222	10,651	15,205	18,043	17,099	13,604	9,484
1956	12,095	14,335	19,027	20,724	19,837	19,657	18,405	20,453	18,299	17,298	12,363	9,939
1957	11,628	11,914	13,567	17,096	11,062	16,000	16,480	20,983	18,492	13,545	9,949	9,025
1958	10,376	11,717	12,064	15,292	16,435	14,050	16,232	20,922	18,410	13,277	10,323	8,951
1959	10,930	12,640	17,354	20,062	19,449	16,518	17,079	18,804	17,964	15,043	12,084	14,167
1960	15,816	17,073	18,037	18,769	15,433	14,857	18,214	17,649	17,923	15,535	10,764	9,547
1961	10,668	12,125	12,067	17,850	16,047	15,708	15,849	19,082	17,788	14,581	11,034	8,767
1962	9,834	12,080	12,628	18,284	12,636	11,135	17,126	18,711	18,005	12,819	10,709	8,815
1963	11,713	13,014	16,820	19,167	14,875	10,009	12,945	16,907	18,365	15,643	11,621	9,615
1964	10,203	12,313	12,380	16,696	12,388	9,455	13,546	17,889	18,484	17,164	12,994	11,382
1965	12,208	12,412	18,670	20,555	19,997	18,855	17,383	20,568	18,251	15,073	12,545	10,243
1966	11,475	11,984	12,447	17,973	11,728	10,330	16,622	17,017	16,696	15,707	11,568	9,025
1967	10,373	11,901	13,043	20,278	19,746	16,541	12,454	17,867	18,565	17,208	12,238	9,883
1968	11,262	12,017	13,144	19,050	16,627	14,891	10,778	15,424	18,165	17,047	12,815	12,647
1969	12,855	14,252	15,953	20,306	19,656	16,968	18,615	20,813	18,199	16,663	10,509	9,404
1970	11,151	12,187	11,931	15,778	14,851	12,724	11,962	17,906	18,531	14,012	9,945	8,664
1971	10,374	11,364	12,614	20,712	19,774	19,529	18,460	20,562	18,397	17,663	14,136	10,513
1972	11,453	12,238	13,149	20,798	19,988	19,465	18,227	20,442	18,481	17,338	15,484	10,822
1973	11,142	11,978	14,301	17,095	10,426	9,294	8,791	13,200	15,611	12,707	8,486	8,365
1974	10,250	11,064	15,648	20,868	20,230	19,782	18,341	20,326	18,207	17,430	14,108	10,316
1975	9,908	11,881	12,002	16,724	14,092	15,275	12,441	19,386	18,478	17,696	12,057	10,625
1976	12,757	14,494	20,058	20,454	19,749	17,872	18,520	20,711	18,409	17,219	16,992	15,337
1977	11,169	11,784	12,290	12,262	9,159	8,658	8,388	10,509	12,687	10,541	9,959	9,229
1978	8,454	11,175	12,768	16,473	13,299	13,930	17,029	19,165	16,328	15,949	11,407	12,763

Table 4: Federal Hydro Generation (aMW) with Hydro Independents for FY 2007

(This table is not applicable to the WP-07 Final Supplemental Proposal)

Table 5: Federal Hydro Generation (aMW) with Hydro Independents for FY 2008

(This table is not applicable to the WP-07 Final Supplemental Proposal)

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929												
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Table 6: Federal Hydro Generation (aMW) with Hydro Independents for FY 2009

(Updated from WP-07 Initial Supplemental Proposal)

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	5,999	7,079	7,234	7,251	5,441	7,428	5,529	6,566	10,543	8,447	6,269	6,070
1930	6,738	7,524	7,436	5,511	7,108	6,324	6,692	6,678	9,359	8,424	6,336	6,165
1931	6,488	7,426	7,297	5,616	5,594	6,153	6,442	6,976	9,857	8,508	6,695	6,499
1932	5,937	7,075	6,963	5,643	5,626	8,209	11,347	13,984	10,942	9,000	6,743	6,830
1933	6,717	6,905	7,957	12,205	10,140	7,533	9,235	11,115	10,613	9,881	9,277	7,099
1934	7,352	9,072	11,832	12,013	11,539	11,497	11,138	11,825	10,407	8,760	5,798	6,117
1935	6,463	6,764	6,885	11,403	12,057	6,471	8,489	10,920	9,375	9,992	7,722	6,068
1936	6,577	7,381	7,036	6,172	6,383	7,438	8,598	12,818	11,218	8,299	6,805	5,855
1937	6,661	7,474	7,377	5,550	5,899	6,253	6,222	7,468	9,683	7,645	7,019	6,286
1938	6,606	7,132	7,848	11,536	9,143	9,737	11,063	13,398	11,498	9,305	6,240	6,760
1939	6,770	7,342	6,757	8,209	6,127	7,502	9,304	12,245	8,422	8,208	5,833	5,663
1940	6,825	7,350	8,590	7,121	7,450	10,732	10,215	10,194	9,931	7,170	5,611	6,193
1941	6,566	7,058	8,181	8,371	6,151	7,788	6,084	6,656	9,924	8,163	6,732	7,072
1942	6,005	6,932	9,158	11,021	7,592	5,421	8,029	9,809	11,583	10,744	8,058	6,263
1943	6,737	7,154	7,552	10,978	11,172	10,499	11,218	13,159	10,807	9,989	7,318	5,723
1944	6,266	7,350	7,173	7,772	5,680	5,481	5,441	7,110	9,023	7,384	6,569	6,638
1945	5,996	7,073	6,717	5,707	6,425	5,938	5,335	10,537	11,650	7,511	6,333	5,997
1946	6,263	7,334	8,484	9,810	8,961	10,761	11,677	13,347	11,287	10,571	7,518	6,585
1947	6,433	7,268	11,298	12,225	11,796	11,631	10,160	12,786	11,332	10,582	7,124	6,458
1948	8,921	9,038	10,096	13,175	9,553	9,246	10,448	13,659	10,521	10,811	9,228	6,987
1949	6,971	7,214	7,961	8,553	8,130	11,410	11,248	13,780	11,190	7,412	5,906	5,378
1950	6,538	6,803	7,502	11,187	11,944	12,726	11,592	12,519	10,174	10,583	8,191	6,706
1951	7,746	8,577	12,000	12,875	11,922	12,677	11,394	13,467	11,122	10,668	8,154	6,337
1952	8,274	7,553	10,206	13,218	10,347	8,324	12,202	13,677	11,722	9,845	7,156	5,956
1953	6,578	7,289	6,801	7,915	11,841	8,317	7,418	12,234	11,174	10,835	7,681	6,474
1954	6,965	7,326	9,067	10,635	12,675	9,243	9,976	13,074	10,350	9,757	10,971	9,129
1955	7,001	7,582	9,493	7,672	7,080	7,062	6,530	10,351	10,633	9,799	9,205	6,151
1956	7,206	8,350	12,080	13,387	12,666	12,700	11,208	13,229	10,283	10,582	7,980	6,635
1957	7,179	7,137	8,459	10,768	6,479	10,299	11,026	13,927	10,749	8,946	6,425	6,200
1958	6,601	7,301	7,519	9,643	10,297	9,111	10,505	13,876	11,286	8,759	6,677	6,136
1959	6,891	7,425	11,052	13,207	12,499	10,670	10,680	12,200	10,455	9,279	7,889	9,328
1960	9,608	10,248	11,408	12,174	9,309	9,588	11,457	11,822	11,249	9,962	6,789	6,534
1961	6,757	7,180	7,583	11,025	10,011	10,259	10,211	12,777	10,482	9,604	7,276	5,864
1962	6,209	7,463	7,681	11,966	7,819	7,071	11,106	12,514	11,411	8,187	6,829	5,986
1963	7,521	7,726	10,744	12,389	8,885	6,192	8,419	11,637	11,646	10,331	7,791	6,437
1964	6,299	7,394	7,746	10,377	7,676	5,691	8,698	12,023	10,484	10,382	8,723	7,425
1965	7,636	7,484	12,075	13,486	12,272	12,468	10,772	13,653	11,516	9,544	8,372	6,622
1966	7,145	7,269	7,910	11,585	7,353	6,382	10,566	11,065	10,484	10,227	7,659	5,949
1967	6,428	7,160	8,010	12,843	12,733	10,548	7,456	11,571	10,422	10,967	8,140	6,672
1968	6,861	7,079	8,252	12,008	10,361	9,179	6,765	10,181	10,996	11,254	8,578	8,068
1969	7,787	8,543	10,298	13,258	13,033	11,185	11,249	13,541	11,192	10,915	7,022	6,246
1970	6,987	7,377	7,467	9,756	9,220	8,189	7,769	11,761	11,482	9,113	6,402	5,859
1971	6,556	7,071	7,667	13,353	12,472	12,599	11,846	13,486	10,575	10,444	9,502	7,007
1972	7,194	7,378	8,533	13,308	12,890	11,476	10,635	13,438	10,181	9,847	10,368	7,058
1973	6,994	7,262	8,970	10,726	6,159	5,789	5,250	8,848	10,112	8,209	5,671	5,577
1974	6,435	6,729	10,092	12,578	11,622	12,462	11,015	13,388	10,231	9,876	9,395	6,782
1975	6,204	7,230	7,447	10,173	8,820	10,121	7,840	12,919	10,960	10,390	7,805	7,079
1976	7,913	8,692	12,330	12,901	12,581	11,735	11,804	13,609	11,165	10,404	11,214	10,219
1977	6,996	7,249	7,263	7,870	5,621	5,437	5,166	6,765	8,211	7,171	6,756	6,359
1978	5,360	7,034	7,972	10,549	8,296	8,988	10,826	12,532	10,348	10,273	7,457	8,380

Table 7: Heavy-Load-Hour Hydro Generation Ratios for FY 2007

(This table is not applicable to the WP-07 Final Supplemental Proposal)

Table 8: Heavy-Load-Hour Hydro Generation Ratios for FY 2008

(This table is not applicable to the WP-07 Final Supplemental Proposal)

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
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Table 9: Heavy-Load-Hour Hydro Generation Ratios for FY 2009

(Updated from WP-07 Initial Supplemental Proposal)

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	1.19623	1.26638	1.18848	1.20838	1.11240	1.14313	1.09329	1.17146	1.21546	1.25162	1.26736	1.28204
1930	1.19923	1.27249	1.18811	1.17768	1.13258	1.15247	1.09421	1.16799	1.25634	1.26570	1.28106	1.27421
1931	1.20058	1.27125	1.19234	1.16664	1.11400	1.14381	1.09850	1.24456	1.25325	1.28095	1.28294	1.27660
1932	1.19956	1.26664	1.18934	1.16491	1.10947	1.13778	1.10768	1.22406	1.17009	1.23964	1.28323	1.27901
1933	1.19917	1.25220	1.21007	1.20163	1.21761	1.13366	1.14307	1.25280	1.07434	1.13130	1.24196	1.28118
1934	1.18395	1.30148	1.21483	1.10212	1.16303	1.23618	1.10124	1.20344	1.22999	1.25533	1.23319	1.27520
1935	1.19696	1.25382	1.19764	1.22709	1.18475	1.12547	1.16711	1.29819	1.21124	1.24636	1.27953	1.28124
1936	1.19843	1.26797	1.19141	1.19122	1.11218	1.14719	1.06202	1.18988	1.22875	1.26643	1.25533	1.27512
1937	1.19944	1.27053	1.19025	1.19379	1.12465	1.15198	1.09805	1.18253	1.21445	1.26675	1.27835	1.27253
1938	1.20220	1.25827	1.18788	1.19072	1.14267	1.21331	1.15304	1.18417	1.17808	1.25492	1.28133	1.27319
1939	1.20296	1.26547	1.18843	1.22432	1.12224	1.14801	1.09613	1.27561	1.25657	1.25847	1.27005	1.28331
1940	1.20136	1.26682	1.19243	1.20372	1.13619	1.21600	1.15260	1.29498	1.24993	1.26745	1.27480	1.27339
1941	1.20167	1.25893	1.20508	1.23285	1.11737	1.14502	1.09453	1.28181	1.25268	1.27306	1.28252	1.27287
1942	1.20092	1.25332	1.26329	1.19307	1.13179	1.13573	1.09868	1.28711	1.16275	1.22903	1.27737	1.27420
1943	1.19891	1.25501	1.19095	1.26655	1.18335	1.19001	1.11390	1.17707	1.15892	1.20490	1.22934	1.27203
1944	1.19985	1.26530	1.18937	1.22319	1.11664	1.13398	1.09056	1.21601	1.23350	1.26931	1.23865	1.27751
1945	1.19524	1.26863	1.18882	1.16888	1.12271	1.14377	1.09035	1.24891	1.20763	1.25485	1.28043	1.27515
1946	1.20081	1.26366	1.19238	1.25049	1.18287	1.21064	1.14180	1.15038	1.17739	1.23062	1.26589	1.27033
1947	1.19995	1.25717	1.25791	1.21081	1.20098	1.23810	1.15633	1.23677	1.19566	1.24299	1.24277	1.28028
1948	1.17597	1.29124	1.25020	1.23569	1.13658	1.19208	1.14134	1.16959	0.99394	1.21568	1.24653	1.28075
1949	1.20483	1.26304	1.20404	1.24396	1.14517	1.20757	1.07375	1.21997	1.20593	1.25806	1.23461	1.27249
1950	1.19965	1.25963	1.19562	1.26155	1.21254	1.20865	1.14183	1.18712	1.03233	1.20051	1.27725	1.26529
1951	1.20496	1.29676	1.26740	1.18123	1.15926	1.21120	1.11063	1.10565	1.18638	1.20905	1.24535	1.27956
1952	1.18310	1.26696	1.25688	1.21958	1.19632	1.22560	1.10984	1.14025	1.19738	1.25206	1.24354	1.27454
1953	1.19601	1.27008	1.18956	1.22789	1.21614	1.13864	1.11341	1.25421	1.11083	1.21390	1.25462	1.27921
1954	1.20327	1.26279	1.23334	1.26578	1.21788	1.21946	1.14129	1.16913	1.02383	1.17055	1.23761	1.27858
1955	1.19780	1.28514	1.23315	1.20275	1.13030	1.14682	1.09456	1.26221	1.01812	1.10579	1.21985	1.27689
1956	1.20315	1.28970	1.25970	1.18288	1.19576	1.21983	1.07814	1.09991	1.05320	1.20126	1.22209	1.26985
1957	1.20654	1.25778	1.24044	1.26111	1.13327	1.14799	1.15607	1.19718	1.07040	1.25103	1.23733	1.27870
1958	1.20173	1.26509	1.18762	1.25662	1.19748	1.22160	1.12528	1.22164	1.13874	1.25344	1.27339	1.28098
1959	1.19910	1.27750	1.26145	1.18000	1.19900	1.20592	1.18695	1.20756	1.09423	1.18204	1.27100	1.28190
1960	1.16751	1.30014	1.26812	1.25329	1.14735	1.20083	1.13077	1.27919	1.18688	1.23884	1.23687	1.26609
1961	1.20186	1.26547	1.20490	1.25618	1.21484	1.22224	1.16009	1.24264	1.01387	1.25598	1.25433	1.28362
1962	1.19801	1.26177	1.19365	1.26449	1.12662	1.14004	1.11937	1.26183	1.19506	1.23666	1.27543	1.28073
1963	1.20548	1.28142	1.26463	1.26785	1.14475	1.18775	1.14915	1.27914	1.20779	1.24259	1.25830	1.28156
1964	1.19393	1.26042	1.19383	1.26761	1.14579	1.14139	1.13200	1.27246	1.06306	1.13113	1.22913	1.27708
1965	1.20302	1.26771	1.24957	1.17608	1.18474	1.21630	1.13361	1.18515	1.14897	1.22942	1.23768	1.27415
1966	1.20633	1.27154	1.22917	1.22841	1.13590	1.14676	1.19784	1.29784	1.23961	1.22645	1.23641	1.27866
1967	1.19617	1.26349	1.19637	1.19516	1.16931	1.18704	1.18008	1.28180	1.06127	1.17576	1.23961	1.27560
1968	1.20482	1.26759	1.22672	1.24590	1.20456	1.21561	1.13374	1.31082	1.18052	1.19145	1.23426	1.28193
1969	1.20437	1.28970	1.25188	1.18092	1.21300	1.19453	1.10230	1.13312	1.17226	1.23633	1.22850	1.27076
1970	1.19868	1.26917	1.19681	1.27075	1.19475	1.14516	1.15010	1.27469	1.16860	1.25203	1.25555	1.28325
1971	1.19786	1.26560	1.18667	1.23072	1.14548	1.19721	1.12724	1.09614	1.10089	1.19857	1.26574	1.27073
1972	1.19770	1.25947	1.22316	1.23034	1.16256	1.11927	1.13058	1.12261	1.01889	1.17029	1.22135	1.27884
1973	1.19913	1.25952	1.23522	1.23985	1.11907	1.14134	1.08999	1.26025	1.25556	1.25885	1.22093	1.27424
1974	1.19679	1.24122	1.26176	1.12373	1.15541	1.20961	1.06784	1.09781	1.01901	1.09553	1.28109	1.26899
1975	1.19589	1.26359	1.19525	1.26035	1.18918	1.21963	1.14989	1.19520	1.11930	1.17050	1.22458	1.28195
1976	1.20943	1.29468	1.25074	1.17848	1.19899	1.18136	1.13861	1.15444	1.18042	1.09427	1.26267	1.28176
1977	1.20226	1.26547	1.19105	1.23051	1.11433	1.12139	1.08231	1.25384	1.22750	1.28531	1.18723	1.28022
1978	1.19208	1.25412	1.18092	1.27026	1.12855	1.23797	1.17008	1.21066	1.19010	1.22469	1.28383	1.27242

1.5.2 Adjustments to Federal Hydro Generation Tables

The following section will discuss adjustments made to Federal hydro generation to account for refilling non-treaty storage in Canada. These storage adjustments are added to the values presented in Table 6 to get the final Federal hydro generation for each of the 50 water years.

The WP-07 Final Proposal made an adjustment to Federal hydro generation for FY 2007 to reconcile differences between the HYDSIM study for FY2006 and the HYDSIM study for FY 2007. A similar adjustment to Federal hydro generation for FY 2009 is not made in this Supplemental Proposal.

1.5.3 Non-Treaty Storage

Adjustments to hydro generation were made for each water year during FY 2009 to reflect the return of non-treaty storage. These adjustments have been updated to reflect the return of non-treaty storage that has been accomplished since the WP-07 Final Proposal.

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. Since the current storage balance is 778 ksfd (thousand second foot days) and a full balance is 1134 ksfd, approximately 356 ksfd needs to be stored in the next three years.

The method constructed to model the return of non-treaty storage attempts to minimize the total cost of this return. For purposes of this analysis, it is assumed that 356 ksfd is returned in FY 2009-2011.

The basic model constructs 50 water year sequences that start in October 2008 and end in July 2011, with each water year incrementing after each October. The first step in each water year sequence is to identify opportunities for returning non-treaty storage flows under extremely high flows. The metric chosen for this step is to determine when spill exceeds 150 kcfs, which results in total dissolved gases violating the gas cap (water quality limit) at Bonneville dam. Storage under these conditions would occur up to 200 ksfd per month, subject to operational limits in Canada. The median amount of this type of storage over the 50 sequences is 150 ksfd with 26 percent of the sequences able to return the full amount. This is the only storage that is allowed in the April-September period, since additional storage would inhibit 2008 FCRPS Biological Opinion flow objectives.

For sequences in which high flows did not return the full amount, the objective of the next step is to find the lowest cost time to return the remaining amount by July 2011 between October and March. Looking at price variability results from AURORA over the fifty water years, the standard deviations as a percentage of monthly average price were determined for each month. These percentages were used to represent daily price variability and are listed in the following table.

	Sept.	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 yield average monthly storage amounts. The median balance over all 50 sequences is 910 ksfd at the end of FY09 with a range of 778-1134 ksfd.

Given that BC Hydro also needs to return its storage, it is assumed that the amounts of these returns are doubled. Even if BC Hydro does not match BPA's storage return over the course of the month, there will be an energy delivery from BPA to BC hydro that is roughly equivalent to the amount of lost Federal generation that would have occurred had they matched.

These average monthly storage amounts are then multiplied by the Federal h/k (a measure of electrical energy produced per unit of streamflow) reported by HYDSIM to create a matrix of monthly adjustments to Federal hydro generation.

An additional effect of not having returned storage is that the storage elevation of Mica is lower than it would have been had all of the storage been returned. Since the h/k of a hydro project is proportional to the storage elevation, the energy production per unit of streamflow has been reduced at Mica. This energy reduction is called head loss and BPA must also deliver this additional energy to BC Hydro. The amounts for these energy deliveries are computed for each month of each sequence based upon the amount of non-treaty storage returned. Given these storage return computations, the hydro generation adjustments associated with refilling non-treaty storage during FY 2009 are provided in Table 12.

Table 10: Federal Hydro Generation Adjustment for Refill of Non-Treaty Storage, FY 2007

(This table is not applicable to the WP-07 Final Supplemental Proposal)

Table 11: Federal Hydro Generation Adjustment for Refill of Non-Treaty Storage, FY 2008

(This table is not applicable to the WP-07 Final Supplemental Proposal)

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929												
1930												
1931												
1932												
1933												
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1972												
1973												
1974												
1975												
1976												
1977												
1978												

Table 12: Federal Hydro Generation Adjustment for Refill of Non-Treaty Storage, FY 2009

(Updated from WP-07 Initial Supplemental Proposal)

Water Year	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep
1929	-412	0	0	0	0	0	0	0	0	0	0	0
1930	0	0	0	0	0	0	0	0	0	0	0	0
1931	0	0	0	-16	0	0	0	0	-288	0	0	0
1932	-59	0	-431	-110	-114	-151	0	0	0	0	0	0
1933	-589	0	0	-429	-271	0	0	0	0	0	0	0
1934	-59	0	0	0	0	0	0	0	0	0	0	0
1935	-78	0	0	0	0	0	0	0	0	0	0	0
1936	-39	0	0	-159	-62	-219	0	0	0	0	0	0
1937	-177	0	0	-114	0	0	0	0	0	0	0	0
1938	-59	0	0	-39	0	-251	0	0	0	0	0	0
1939	0	0	0	-19	0	0	0	0	0	0	0	0
1940	0	0	-20	-86	-41	0	0	0	0	0	0	0
1941	-79	0	0	-190	-248	-262	-217	0	0	0	0	0
1942	-79	0	0	-38	0	0	0	0	0	0	0	0
1943	0	0	0	0	0	0	0	0	0	0	0	0
1944	0	0	0	-19	-21	-45	0	0	0	0	0	0
1945	0	0	0	0	0	0	0	0	0	0	0	0
1946	0	0	0	0	0	0	0	-262	0	0	0	0
1947	0	0	0	0	0	0	0	-445	0	0	0	0
1948	0	0	0	0	0	0	0	0	-53	0	0	0
1949	0	0	0	-42	-15	-15	0	-49	0	0	0	0
1950	0	0	0	0	0	0	0	-271	0	0	0	0
1951	0	0	0	0	-21	0	0	0	0	0	0	0
1952	0	0	0	0	0	0	0	0	-47	0	0	0
1953	0	0	0	0	0	0	0	0	-335	0	0	0
1954	0	0	0	0	0	0	-119	-68	-248	0	0	0
1955	0	0	0	0	0	0	0	-404	-288	0	0	0
1956	0	0	0	0	-41	-37	0	0	0	0	0	0
1957	0	0	0	-20	-17	-18	0	0	-81	0	0	0
1958	-358	0	0	-47	0	-58	0	0	0	0	0	0
1959	0	0	0	-38	-76	-92	0	0	-66	0	0	0
1960	0	0	0	-38	-21	0	0	0	0	0	0	0
1961	0	0	0	-16	-21	0	0	0	0	0	0	0
1962	0	0	0	-19	0	0	0	0	-288	0	0	0
1963	0	0	0	-75	-90	-75	0	0	0	0	0	0
1964	0	0	0	-31	0	0	0	0	0	0	0	0
1965	0	0	0	-31	-17	0	0	0	-227	0	0	0
1966	0	0	0	-38	-38	-55	0	0	0	0	0	0
1967	0	0	0	0	0	0	0	-270	0	0	0	0
1968	0	0	0	0	0	0	0	0	0	0	0	0
1969	0	0	0	0	0	0	0	-260	-232	0	0	0
1970	0	0	0	0	0	0	0	-197	0	0	0	0
1971	0	0	0	0	0	0	0	0	0	0	0	0
1972	0	0	0	0	0	0	0	-50	0	0	0	0
1973	0	0	0	0	0	-18	0	0	-394	0	0	0
1974	0	0	-81	-195	-67	-74	0	-243	0	0	0	0
1975	-216	0	0	-57	0	0	0	0	0	0	0	0
1976	-116	0	0	-210	-207	-332	0	0	0	0	0	0
1977	-111	0	0	-457	0	0	0	0	0	0	0	0
1978	-589	0	0	0	-596	0	0	0	0	0	0	0

1.5.4 FY 2007 Storage Adjustment

This storage adjustment is not made in the Supplemental rate case.

Table 13: Federal Hydro Generation Storage Adjustment for FY 2007

(This Table is not applicable to the WP-07 Final Supplemental Proposal)

1.5.5 Variable 4(h)(10)(C) Fish Credits

The 4(h)(10)(C) credit is a provision in the 1980 Pacific Northwest Electric Power Planning and Conservation Act that allows BPA and its ratepayers to receive a credit for non-power fish and wildlife impacts attributable to the Federal projects. The amount of 4(h)(10)(C) credits that BPA can collect for each of the 50 water years for FY 2009 is determined by summing the costs of the operational impacts, the expenses, and the capital costs associated with fish and wildlife mitigation measures, and then multiplying the total cost by 0.223 (22.3 percent).

The costs of the operational impacts are calculated for each of the 50 water years in RiskMod for FY 2009 by multiplying HLH and LLH spot market electricity prices from AURORA by the amount of power purchases (aMW) that qualifies for 4(h)(10)(C) credits. The amounts of power purchases (aMW) that qualifies for 4(h)(10)(C) credits are derived external to RiskMod, but are used in RiskMod to calculate the dollar amount of the 4(h)(10)(C) credits. Documentation of the power purchases used for FY 2009, along with a description of the methodology used to derive the amounts of power purchases (aMW) associated with the 4(h)(10)(C) credits, are contained in the FY 2009 Load Resource Study Documentation, WP-07-FS-BPA-09A. The capital costs for FY 2009 are $50 million per year and the expenses are $200 million per year (*see* FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10).

1.5.6 Sampling Hydro Generation

Federal and PNW hydro generation variability is modeled in RiskMod by randomly sampling, in the @RISK computer software, each of the 50 water years (1929-1978) and using the associated hydro generation data in the same continuous manner that the data are developed by HydroSim when performing a continuous study. This random selection is accomplished by sampling values ranging from 1929-1978 from a uniform probability distribution in a risk simulation model. Given the water year, the corresponding monthly Federal and PNW hydro generation data and the HOSS HLH hydro generation ratios for that water year are selected. The uniform probability distribution was selected for modeling hydro generation risk because it appropriately assigns equal probability to each of the 50 water years being sampled. Graph 2 reports the number of times that each of the 50 water years were sampled from a uniform probability distribution for 3000 simulations. As shown in this graph, each of the 50 water years was sampled 60 times.

Surplus energy revenues and power purchase expenses reported in the Revenue Forecast component of the Wholesale Power Rate Development Study and used in setting rates in the RAM2007 are derived by performing a 50 water year run of RiskMod. (*See* the Revenue Forecast component of the FY 2009 Wholesale Power Rate Development Study, WP-07-FS-BPA-13; and discussion of the RAM2007 components of the FY 2009 Wholesale Power Rate Development Study, WP-07-FS-BPA-13.)

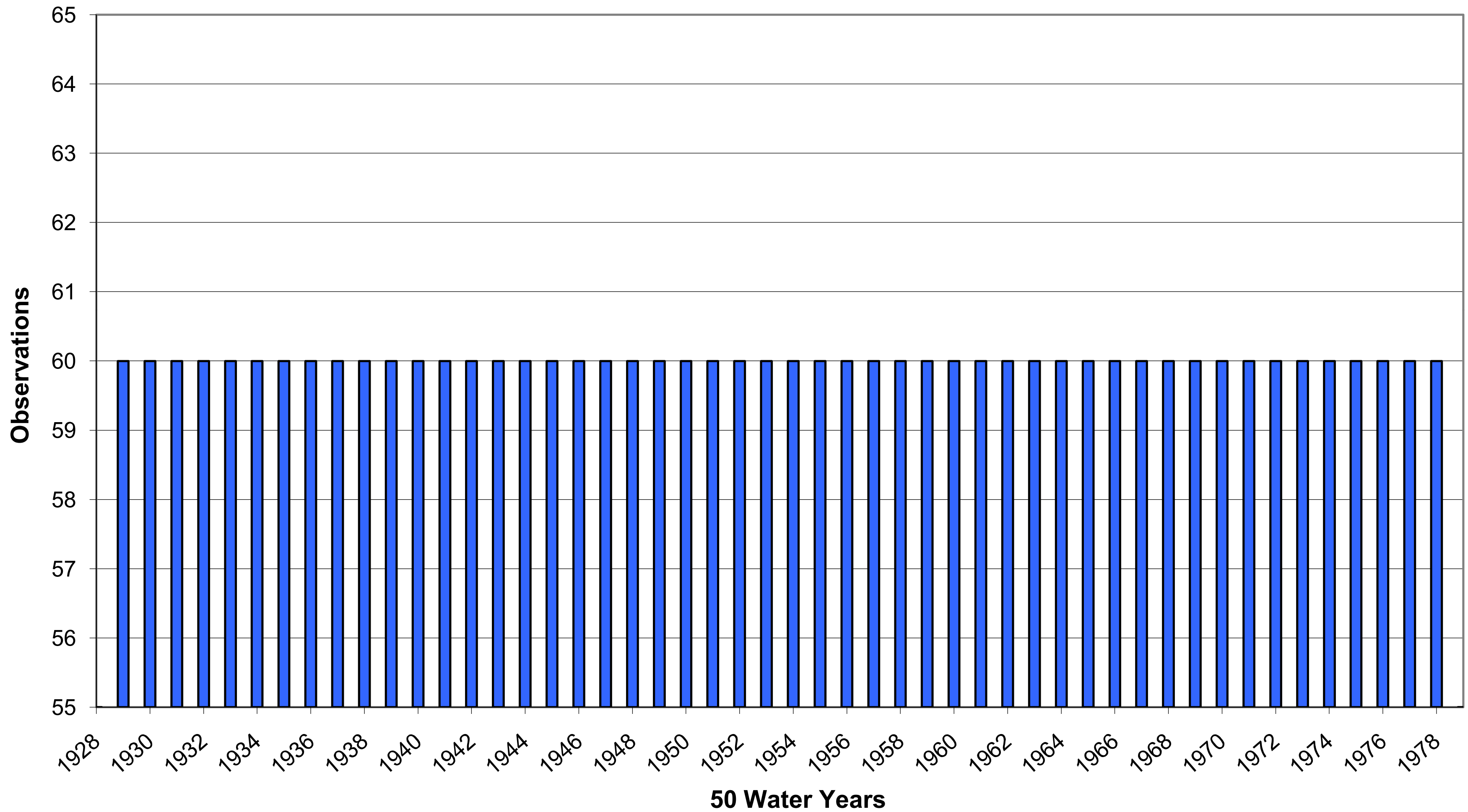
For the 50 water year run of RiskMod, average surplus energy revenues, 4(h)(10)(C) credits and power purchase expenses are estimated using Federal HLH and LLH hydro generation for the 50 water years. No other risk factors, except for hydro generation, are allowed to vary when performing the 50 water year run of RiskMod. HLH and LLH spot market electricity prices estimated by the AURORA Model using PNW hydro generation for the 50 water years are input into RevSim and used to calculate surplus energy revenues, 4(h)(10)(C) credits, and power purchase expenses. Results for FY 2009 from the 50 water year run of RiskMod are reported in the Revenue Forecast component of the FY 2009 Wholesale Power Rate Development Study, WP-07-FS-BPA-13. Results for FY 2010-2013 are provided to RAM2007 to inform the 7(b)(2) rate test (see FY 2009 7(b)(2) Rate Test Study, WP-07-FS-BPA-14). The results FY 2010-2013 are provided in Table 13A. For the Risk Simulation run of RiskMod, Federal, and PNW hydro generation data for each of the 50 water years are combined with additional risk factors to quantify net revenue risk.

Table 13A: 50 Water Year Results Provided to RAM2007 for FY 2010-2013
THIS IS A NEW TABLE

Table 13A: RiskMod Results Used in the 7(b)(2) Rate Test

	Federal Surplus Energy Revenues ($ Thousand)	Balancing Power Purchase Expenses ($ Thousand)
FY 2010	584,742	81,371
FY 2011	636,249	69,169
FY 2012	666,468	94,626
FY 2013	701,190	83,556

Graph 2: Number of Times PNW and Federal Hydro Generation for the 50 Water Years were Sampled Based on 3,000 Sampled Values (No change from WP-07 Initial Supplemental Proposal)



1.5.7 Use of PNW Hydro Generation Risk in AURORA

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

1.6 PNW and BPA Load Risk Factor

PNW load risk is incorporated into the Risk Analysis 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 PBL's surplus energy revenues and power purchase expenses. This impact is accounted for by inputting into the AURORA Model various PNW load values and having it estimate the associated HLH and LLH spot market electricity prices.

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

1.6.1 PNW and BPA Load Variability

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

The PNW Load Risk Model is designed to incorporate forecasted monthly load data from the AURORA Model such that, when no risk is being simulated for CY 2008-2009, the forecasted monthly loads match the sum of the forecasted loads for the three regions (Oregon/Washington, Idaho, and Montana) that comprise the PNW in the AURORA Model. This process results in the simulated loads reflecting variability in loads relative to the forecasted loads that AURORA uses to perform the Market Price Forecast Study. (*See* FY 2009 Market Price Forecast Study, WP-07-FS-BPA-11.)

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 2008-2009 and then, subsequently, simulating the impact of monthly load swings due to weather on the simulated monthly loads that include load growth.

1.6.2 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. Under this method, simulated annual average loads randomly increase and decrease through time from the annual average load level of the prior year with the results including outcomes that represent periods of strong load growth, weak load growth, and vacillating positive and negative load growth. The mean-reverting technique causes simulated annual loads to tend to revert to the forecasted loads as loads move further from forecasted loads (either higher or lower).

Input data from the AURORA Model used in the PNW Load Risk Model are the following: (1) annual average CY 2007 PNW load; (2) forecasted annual load growth for CY 2008-2009; and (3) monthly load shaping factors (values relative to 1.00) that are derived for use in AURORA by dividing historical monthly loads by historical annual average loads. (*See* FY 2009 Market Price Forecast Study, WP-07-FS-BPA-11.) Inputting the data used by the AURORA Model allows the PNW Load Risk Model to replicate the forecasted monthly PNW loads in AURORA.

Load growth variability is incorporated into the PNW Load Risk Model by sampling values from standard normal distributions (normal distributions with a mean of zero and a standard deviation of one) in @RISK, multiplying the sampled values by an annual load growth standard deviation, and adding the simulated positive and negative values to the annual load level of the prior year. The values sampled from the standard normal distribution are in terms of the number of positive or negative standard deviations.

The annual load growth standard deviation used in the PNW Load Risk Model is 3.21 percent with the cumulative annual load growth standard deviation over a two year period being 4.16 percent. These values were derived from historical annual Western Electricity Coordinating Council (WECC) load data for the Northwest Power Pool Area during 1982-2005. The source of this data was a publication by the WECC titled, 10-Year Coordinated Plan Summary, Planning and Operation for Electric System Reliability, Western Electricity Coordinating Council, July 2006, at 61. Variability in monthly loads due to load growth risk is derived by multiplying variable annual loads by deterministic monthly load shape factors. The historical WECC load data and the cumulative annual load growth standard deviation calculations by BPA for the PNW are reported in Table 14.

Table 14: PNW and California Load Growth Standard Deviation Calculations for One to Seven Years (Updated from WP-07 Initial Supplemental Proposal)

Pacific Northwest (NWPP)

Year	NWPP	% Change Over 1 Yr	% Change Over 2 Yrs	% Change Over 3 Yrs	% Change Over 4 Yrs	% Change Over 5 Yrs	% Change Over 6 Yrs	% Change Over 7 Yrs
1982	26,804							
1983	26,861	0.21%						
1984	28,642	6.63%	6.86%					
1985	29,372	2.55%	9.35%	9.58%				
1986	28,927	-1.52%	1.00%	7.69%	7.92%			
1987	29,954	3.55%	1.98%	4.58%	11.52%	11.75%		
1988	31,986	6.78%	10.58%	8.90%	11.68%	19.08%	19.34%	
1989	33,265	4.00%	11.05%	15.00%	13.25%	16.14%	23.84%	24.11%
1990	34,372	3.33%	7.46%	14.75%	18.82%	17.02%	20.01%	27.96%
1991	34,840	1.36%	4.74%	8.92%	16.31%	20.44%	18.62%	21.64%
1992	35,114	0.79%	2.16%	5.56%	9.78%	17.23%	21.39%	19.55%
1993	35,708	1.69%	2.49%	3.89%	7.34%	11.63%	19.21%	23.44%
1994	36,107	1.12%	2.83%	3.64%	5.05%	8.54%	12.88%	20.54%
1995	36,336	0.63%	1.76%	3.48%	4.29%	5.71%	9.23%	13.60%
1996	38,151	5.00%	5.66%	6.84%	8.65%	9.50%	10.99%	14.69%
1997	37,911	-0.63%	4.34%	5.00%	6.17%	7.96%	8.81%	10.30%
1998	39,144	3.25%	2.60%	7.73%	8.41%	9.62%	11.48%	12.35%
1999	39,829	1.75%	5.06%	4.40%	9.61%	10.31%	11.54%	13.43%
2000	40,479	1.63%	3.41%	6.78%	6.10%	11.40%	12.11%	13.36%
2001	36,998	-8.60%	-7.11%	-5.48%	-2.41%	-3.02%	1.82%	2.47%
2002	39,121	5.74%	-3.36%	-1.78%	-0.06%	3.19%	2.54%	7.67%
2003	38,881	-0.61%	5.09%	-3.95%	-2.38%	-0.67%	2.56%	1.92%
2004	39,646	1.97%	1.34%	7.16%	-2.06%	-0.46%	1.28%	4.58%
2005	41,199	3.92%	5.96%	5.31%	11.35%	1.78%	3.44%	5.25%

Avg	**0.019**	**0.039**	**0.056**	**0.075**	**0.093**	**0.117**	**0.139**
StDev	**0.0321**	**0.0416**	**0.0503**	**0.0591**	**0.0692**	**0.0740**	**0.0799**
Min	**-0.086**	**-0.071**	**-0.055**	**-0.024**	**-0.030**	**0.013**	**0.019**
Max	**0.068**	**0.111**	**0.150**	**0.188**	**0.204**	**0.238**	**0.280**

NWPP & Cal/Mex Correlation (Post 1986)	**0.9077**

California (Cal/Mex)

Year	CAL/MEX	% Change Over 1 Yr	% Change Over 2 Yrs	% Change Over 3 Yrs	% Change Over 4 Yrs	% Change Over 5 Yrs	% Change Over 6 Yrs	% Change Over 7 Yrs
1987	24,498							
1988	25,491	4.05%						
1989	26,153	2.60%	6.76%					
1990	27,021	3.32%	6.00%	10.30%				
1991	26,324	-2.58%	0.65%	3.27%	7.46%			
1992	27,021	2.65%	0.00%	3.32%	6.00%	10.30%		
1993	26,895	-0.46%	2.17%	-0.46%	2.84%	5.51%	9.79%	
1994	27,820	3.44%	2.96%	5.68%	2.96%	6.37%	9.14%	13.56%
1995	27,454	-1.31%	2.08%	1.61%	4.29%	1.61%	4.98%	7.70%
1996	28,390	3.41%	2.05%	5.56%	5.07%	7.85%	5.07%	8.56%
1997	29,326	3.30%	6.82%	5.42%	9.04%	8.53%	11.41%	8.53%
1998	29,064	-0.90%	2.37%	5.86%	4.47%	8.06%	7.56%	10.41%
1999	29,943	3.02%	2.10%	5.47%	9.06%	7.63%	11.33%	10.82%
2000	31,461	5.07%	8.25%	7.28%	10.82%	14.59%	13.09%	16.98%
2001	30,708	-2.39%	2.55%	5.66%	4.71%	8.16%	11.85%	10.38%
2002	31,689	3.20%	0.73%	5.83%	9.03%	8.06%	11.62%	15.43%
2003	31,632	-0.18%	3.01%	0.54%	5.64%	8.84%	7.86%	11.42%
2004	32,945	4.15%	3.96%	7.29%	4.72%	10.03%	13.35%	12.34%
2005	32,534	-1.25%	2.85%	2.67%	5.95%	3.41%	8.65%	11.94%

Avg	**0.016**	**0.033**	**0.047**	**0.061**	**0.078**	**0.097**	**0.115**
StDev	**0.0251**	**0.0235**	**0.0274**	**0.0242**	**0.0309**	**0.0277**	**0.0279**
Min	**-0.026**	**0.000**	**-0.005**	**0.028**	**0.016**	**0.050**	**0.077**
Max	**0.051**	**0.082**	**0.103**	**0.108**	**0.146**	**0.134**	**0.170**

Note: For the reason describe below, California load growth variability was calculated using data that starts in 1987.

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

1.6.3 PNW and BPA Load Risk Due to Weather

Monthly PNW (and indirectly BPA) load variability due to weather conditions is quantified by first sampling values from standard normal distributions in @RISK, then multiplying the sampled values by monthly load standard deviations, and finally adding the resulting positive and negative values to the simulated loads after load growth.

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

1.6.4 Derivation of PNW/BPA 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

n is the number of independent random variables

In the case of BPA's analysis, the number of independent random variables is the number of days in a month and the standard deviation for all the independent random variables is the daily load standard deviations for each month. The PNW monthly load standard deviations for each month are derived by inserting values for the number of days in each month and the daily load standard deviations for each month into the equation above. Table 15 contains the calculations performed to derive PNW monthly load standard deviations from daily load standard deviations for each month. These monthly load standard deviations are input into the PNW Load Risk Model to quantify monthly load variability due to weather.

Table 15: Derivation of Load-Weighted, Monthly Load Standard Deviations for PNW (No change from WP-07 Initial Supplemental Proposal)

PNW

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

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

1.6.5 Modeling Methodology

In order for the PNW Load Risk Model to simulate the cumulative annual load growth standard deviation reflected in the historical data over a two year period, a mean-reversion decay parameter was developed so that the simulated cumulative annual load growth standard deviation for year two (CY 2009) would be calibrated to the values in the historical data. No mean-reversion decay parameter was developed for year 1, since the load growth standard deviation used in the probability distributions is the annual load growth standard deviation for a year.

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

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 annual load

<u>Annual load movements through time were modeled as follows:</u>

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)))

1.6.6 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 value for CY 2009 to test how well the values computed in step (2) compare.

BPA used the statistical approach of minimizing the sum of residuals squared 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.

1.6.7 Model and Results

Tables 16 and 17 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.

Table 16: PNW and California Load Variability Calibration (Updated from WP-07 Initial Supplemental Proposal)

Mean-Reversion Calibration Section	CY08	CY09
Mean Reversion Rate	N/A	5.470
Additional California Annual Load Volatility Adjustment Factors	0.984	0.160
Sum of Residuals ^2 for PNW (CY08-09)	62	
Sum of Residuals ^2 for California (CY08-09)	2,035	
Sum of Residuals ^2 for PNW & California (CY08-09)	2,098	

PNW Load Risk Result Section	Avg 08-09	CY 2008	CY 2009
Simulated Annual PNW Loads (aMW)	24,644	24,342	24,946
Forecasted Annual PNW Loads (aMW)	24,645	24,343	24,947
Sim Less Forecast	(1)	(1)	(1)
	Avg 08-09	**CY 2008**	**CY 2009**
Sim Load Stdev	914	790	1,037
Historical Load Stdev Applied to Current Load Forecast	910	783	1,037
Sim Less Hist Stdev	4	8	0

California Load Risk Result Section	Avg 08-09	CY 2008	CY 2009
Simulated Annual Calif Loads (aMW)	33,021	32,678	33,364
Forecasted Annual Calif Loads (aMW)	33,036	32,690	33,383
Sim Less Forecast	(15)	(12)	(19)
	Avg 08-09	**CY 2008**	**CY 2009**
Sim Load Stdev	826	822	831
Historical Load Stdev Applied to Current Load Forecast	804	822	786
Sim Less Hist Stdev	23	0	45

Table 17: PNW Load Risk Model for 2008 - 2009
(Updated from WP-07 Initial Supplemental Proposal)

PNW Load Variability

PNW Load Growth Uncertainty:

Forecasted Calendar Year (2007) Annual Average PNW Loads	24,338				
Forecasted PNW Load Growth for 2008; Source: Aurora	0.02%				
Forecasted PNW Load Growth for 2009; Source: Aurora	2.48%				
Annual Load Growth Std Dev; Source: WECC Load Data (1982-2005)	3.21%				
				Additional	
Estimated Base Case Loads		*Std Normal Dist*	Base MR	MR Decay Factors	
CY 2008	24,343	*0.0*	Entered zero; i.e., no load variability		
CY 2009	24,947	*0.0*	1.00	5.47	

Load Growth Dev from any specified forecasted load level

CY 2008	*24343*
CY 2009	*24947*

PNW Load Variability Due to Load Growth Uncertainty

Calendar Year 2008

	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Oct '08	Nov '08	Dec '08	Simple Avg
Average Annual PNW Loads (Average Energy in aMW)	24343	24343	24343	24343	24343	24343	24343	24343	24343	24343	24343	24343	
PNW Monthly Load Shapes (Source: AURORA)	1.104	1.065	1.021	0.945	0.934	0.961	1.003	1.002	0.930	0.921	1.023	1.093	
Simulated Monthly PNW Loads (Average Energy in aMW)	26867	25920	24843	22997	22737	23381	24404	24382	22640	22429	24902	26599	24,342 aMW

PNW Load Variability Due to Load Growth and Weather Uncertainty

	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Oct '08	Nov '08	Dec '08	Simple Avg
PNW Loads after Load Growth (Average Energy in aMW)	26867	25920	24843	22997	22737	23381	24404	24382	22640	22429	24902	26599	24,342 aMW
Monthly Load Standard Deviation	1.53%	1.69%	1.18%	1.51%	1.36%	1.22%	1.65%	1.19%	1.43%	1.45%	1.50%	1.62%	
Random PNW Loads (Average Energy in aMW)	*26,867*	*25,920*	*24,843*	*22,997*	*22,737*	*23,381*	*24,404*	*24,382*	*22,640*	*22,429*	*24,902*	*26,599*	24,342 aMW

Table 17: PNW Load Risk Model for 2009 (Continued)
(Updated for FY 2008-2009 from WP-07 Initial Supplemental Proposal)

PNW Load Variability

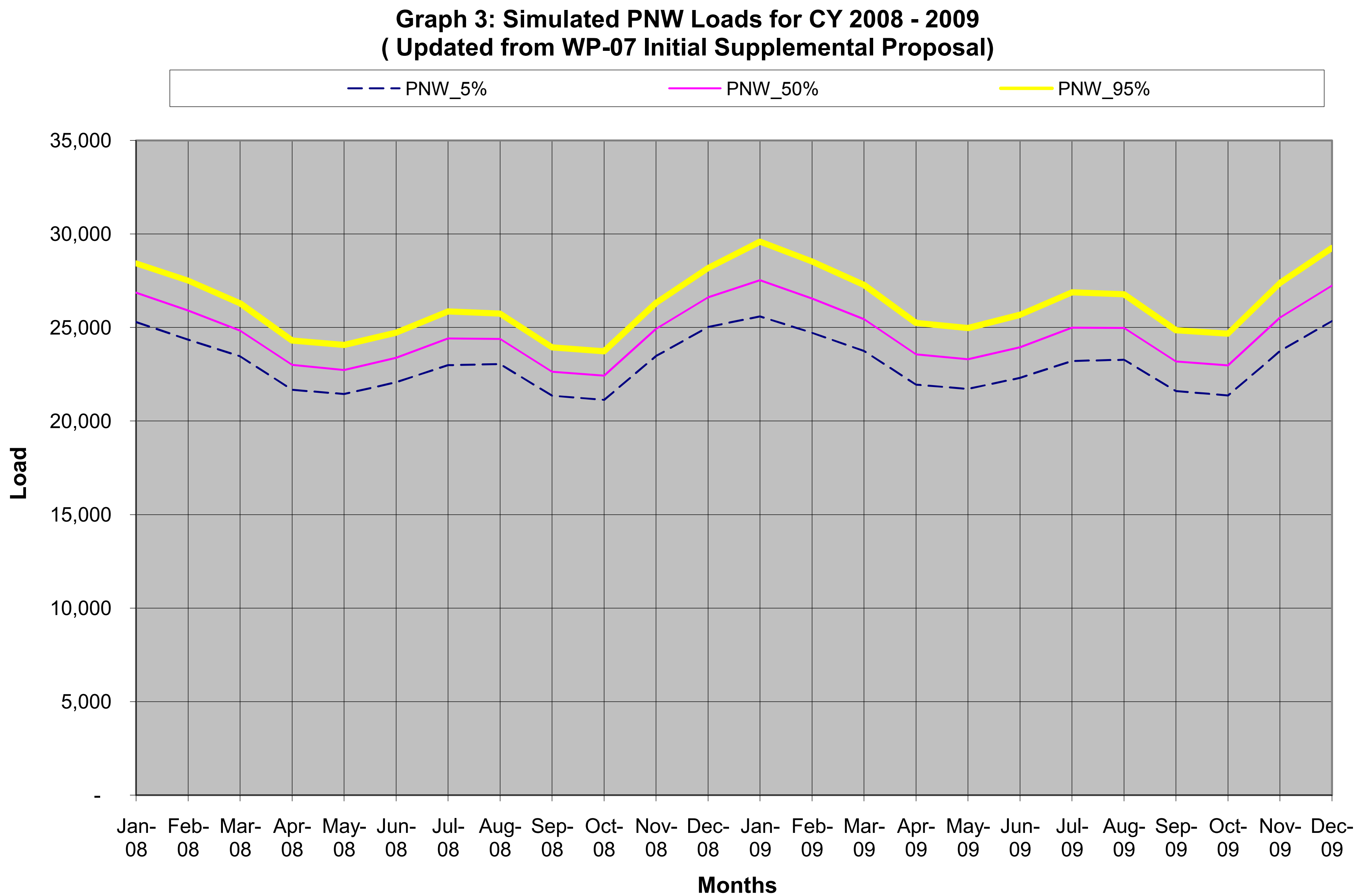
PNW Load Variability Due to Load Growth Uncertainty

Calendar Year 2009

	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	Oct '09	Nov '09	Dec '09	Simple Avg
Average Annual PNW Loads (Average Energy in aMW)	24947	24947	24947	24947	24947	24947	24947	24947	24947	24947	24947	24947	
PNW Monthly Load Shapes (Source: AURORA)	**1.104**	**1.065**	**1.021**	**0.945**	**0.934**	**0.961**	**1.003**	**1.002**	**0.930**	**0.922**	**1.023**	**1.093**	
Simulated Monthly PNW Loads (Average Energy in aMW)	27539	26568	25464	23572	23306	23966	25014	24991	23206	22990	25525	27264	**24,950 aMW**

PNW Load Variability Due to Load Growth and Weather Uncertainty

	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	Oct '09	Nov '09	Dec '09	Simple Avg
PNW Loads after Load Growth (Average Energy in aMW)	27539	26568	25464	23572	23306	23966	25014	24991	23206	22990	25525	27264	**24,950 aMW**
Monthly Load Standard Deviation	1.53%	1.69%	1.18%	1.51%	1.36%	1.22%	1.65%	1.19%	1.43%	1.45%	1.50%	1.62%	
Random PNW Loads (Average Energy in aMW)	***27,539***	***26,568***	***25,464***	***23,572***	***23,306***	***23,966***	***25,014***	***24,991***	***23,206***	***22,990***	***25,525***	***27,264***	**24,950 aMW**



Graph 3: Simulated PNW Loads for CY 2008 - 2009
(Updated from WP-07 Initial Supplemental Proposal)
PNW_5%
PNW_50%
PNW_95%
Load
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
Jan-08
Feb-08
Mar-08
Apr-08
May-08
Jun-08
Jul-08
Aug-08
Sep-08
Oct-08
Nov-08
Dec-08
Jan-09
Feb-09
Mar-09
Apr-09
May-09
Jun-09
Jul-09
Aug-09
Sep-09
Oct-09
Nov-09
Dec-09
Months

1.6.8 Use of Simulated PNW Loads in AURORA

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

1.7 California Hydro Generation Risk Factor

California hydro generation risk is incorporated into the Risk Analysis 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 power purchase expenses.

1.7.1 Modeling Hydro Risk

California hydro generation risk is incorporated into the Risk Analysis 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 the AURORA Model. 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 18.

1.7.2 Sampling Hydro Generation

California hydro generation risk is modeled in RiskMod by randomly sampling, in the @RISK computer software, values from 1 to 18 (which represent each of the 18 hydro generation years) and using the associated hydro generation data in a continuous manner like that used for the 50 water year analysis. Given the sampled hydro generation year, the corresponding monthly California hydro generation data for that year are selected for FY 2009.

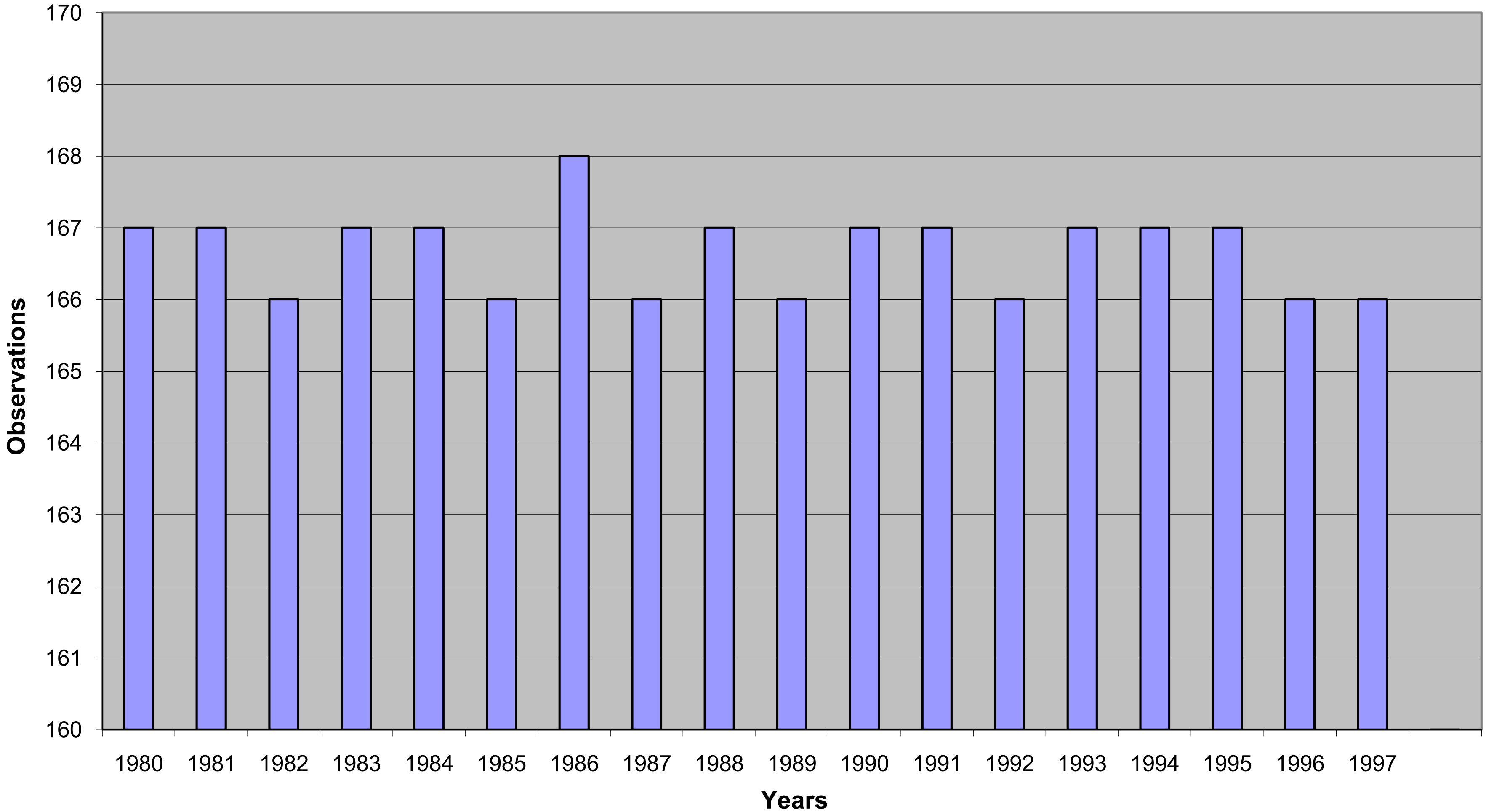
Table 18: California Hydro Generation for 1980 - 1997
(No change from WP-07 Initial Supplemental Proposal)

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

Source: Energy Information Administration (EIA) - Electric Power Monthly. Electric Utility Hydroelectric Net Generation by Census Division and State, 1980 - 1997

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 3000 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 3000 simulations is 166.7 (3000/18). These results in Graph 4 indicate that all years, except for 1986, were sampled either 166 or 167 times. The hydro generation data for 1986 were sampled 168 times.

Graph 4: Number of Times California Hydro Generation for 18 Years were Sampled Based on 3,000 Sampled Values (No change from WP-07 Initial Supplemental Proposal)



1.7.3 Use of California Hydro Generation Risk in AURORA

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

1.8 California Load Risk Factor

California load risk is incorporated into the Risk Analysis 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 power purchase expenses. This impact is accounted for by inputting into the AURORA Model various California load values and having it estimate the associated HLH and LLH spot market electricity prices.

1.8.1 California Load Variability

The California Load Risk Model is designed to incorporate forecasted monthly load data from the AURORA Model such that, when no risk is being simulated for CY 2008-2009, the forecasted monthly loads match the sum of the forecasted loads for the two regions (southern and northern California) that comprise California in the AURORA Model. This process results in the simulated loads reflecting variability in loads relative to the forecasted loads that AURORA uses to perform the Market Price Forecast Study. (*See* FY 2009 Market Price Forecast Study, WP-07-FS-BPA-11.)

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 2008-2009 and then, subsequently, simulating the impact of monthly load swings due to weather on the simulated monthly loads that include load growth.

1.8.2 Annual California Load Growth Risk

Annual California 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 the annual average load in a given year being the annual average load level from the previous year. Under this method, simulated annual average loads randomly increase and decrease through time from the annual average load level of the prior year with the results including outcomes that represent periods of strong load growth, weak load growth, and vacillating positive and negative load growth. The mean-reverting technique causes simulated annual loads to tend to revert to the forecasted loads as loads move further from forecasted loads (either higher or lower).

Input data from the AURORA Model used in the California Load Risk Model are the following: (1) annual average CY 2007 California loads; (2) forecasted annual load growth for CY 2008-2009; and (3) monthly load shaping factors (values relative to 1.00) that are derived for use in AURORA by dividing historical monthly loads by historical annual average loads (*see* FY 2009 Market Price Forecast Study, WP-07-FS-BPA-11). Inputting the data used by the AURORA Model allows the California Load Risk Model to replicate the forecasted monthly California loads in AURORA.

Load growth variability is incorporated into the California Load Risk Model by multiplying an annual load growth standard deviation by values sampled from standard normal distributions (normal probability distributions with a mean of zero and a standard deviation of one) in @RISK and adding the simulated positive and negative values to the annual load level of the prior year. The values sampled from the standard normal distribution are in terms of the number of positive or negative standard deviations.

The annual load growth standard deviation used in the California Load Risk Model is 2.51 percent with the cumulative annual load growth standard deviation over a two year period being 2.35 percent. These values were derived from historical annual Western Electricity Coordinating Council (WECC) load data for the California/Mexico Power Area during 1987-2005. The source of this data was a publication by the WECC titled, 10-Year Coordinated Plan Summary, Planning and Operation for Electric System Reliability, Western Electricity Coordinating Council, July 2006, at 61. Variability in monthly loads due to load growth variability is derived by multiplying variable annual loads by deterministic monthly load shape factors. The historical WECC load data and the cumulative annual load growth standard deviation calculations by BPA for California, along with the PNW, are reported in Table 14.

1.8.3 California Load Risk Due to Weather

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

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

1.8.4 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

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

Table 19: Derivation of Load-Weighted, Monthly Load Standard Deviations for California
(No change from WP-07 Initial Supplemental Proposal)

California

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

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

1.8.5 Modeling Methodology

Based on a correlation analysis of PNW and California loads from 1987-2005 that indicates they are highly correlated (the correlation coefficient between these loads is 0.9077 (*See* Table 14), 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 one and two (CY 2008-2009) 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.

<u>Annual load movements through time were modeled as follows:</u>

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.

1.8.6 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 2008-2009 to test how well the values computed in step (2) compare.

BPA used the statistical approach of minimizing the sum of residuals squared 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.

1.8.7 Model and Results

Table 16 and Table 20 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.

Table 20: California Load Risk Model for 2008 - 2009
(Updated from WP-07 Initial Supplemental Proposal)

California Load Variability

California Load Growth Uncertainty:

Forecasted Calendar Year (2007) Annual Average California Loads	32,696
Forecasted California Load Growth for 2008; Source: Aurora	-0.02%
Forecasted California Load Growth for 2009; Source: Aurora	2.12%
Annual Load Growth Std Dev; Source: WECC Load Data (1987-2005)	2.51%

Estimated Base Case Loads		Std Normal Dist (Same as PNW)	Additional Adj Factors
CY 2008	32,690	0.0	0.984
CY 2009	33,383	0.0	0.160

Load Growth Dev from any specified forecasted load level	
CY 2008	*32690*
CY 2009	*33383*

California Load Variability Due to Load Growth Uncertainty

Calendar Year 2008

	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Oct '08	Nov '08	Dec '08	Simple Avg
Average Annual California Loads (Average Energy in aMW)	32690	32690	32690	32690	32690	32690	32690	32690	32690	32690	32690	32690	
California Monthly Load Shapes (Source: AURORA)	0.954	0.930	0.930	0.920	0.974	1.051	1.094	1.120	1.082	0.986	0.952	1.002	
Simulated Monthly California Loads (Average Energy in aMW)	31195	30405	30405	30078	31849	34352	35772	36617	35366	32232	31115	32750	32,678 aMW

California Load Variability Due to Load Growth and Weather Uncertainty

	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Oct '08	Nov '08	Dec '08	Simple Avg
California Loads after Load Growth (Average Energy in aMW)	31195	30405	30405	30078	31849	34352	35772	36617	35366	32232	31115	32750	32,678 aMW
Monthly Load Standard Deviation	1.46%	1.54%	1.48%	1.50%	1.70%	1.76%	1.76%	1.59%	1.88%	1.52%	1.50%	1.46%	
Random California Loads (Average Energy in aMW)	*31,195*	*30,405*	*30,405*	*30,078*	*31,849*	*34,352*	*35,772*	*36,617*	*35,366*	*32,232*	*31,115*	*32,750*	32,678 aMW

Table 20: California Load Risk Model for 2009 (Continued)
(Updated for FY 2008-2009 from WP-07 Initial Supplemental Proposal)

California Load Variability

California Load Variability Due to Load Growth Uncertainty

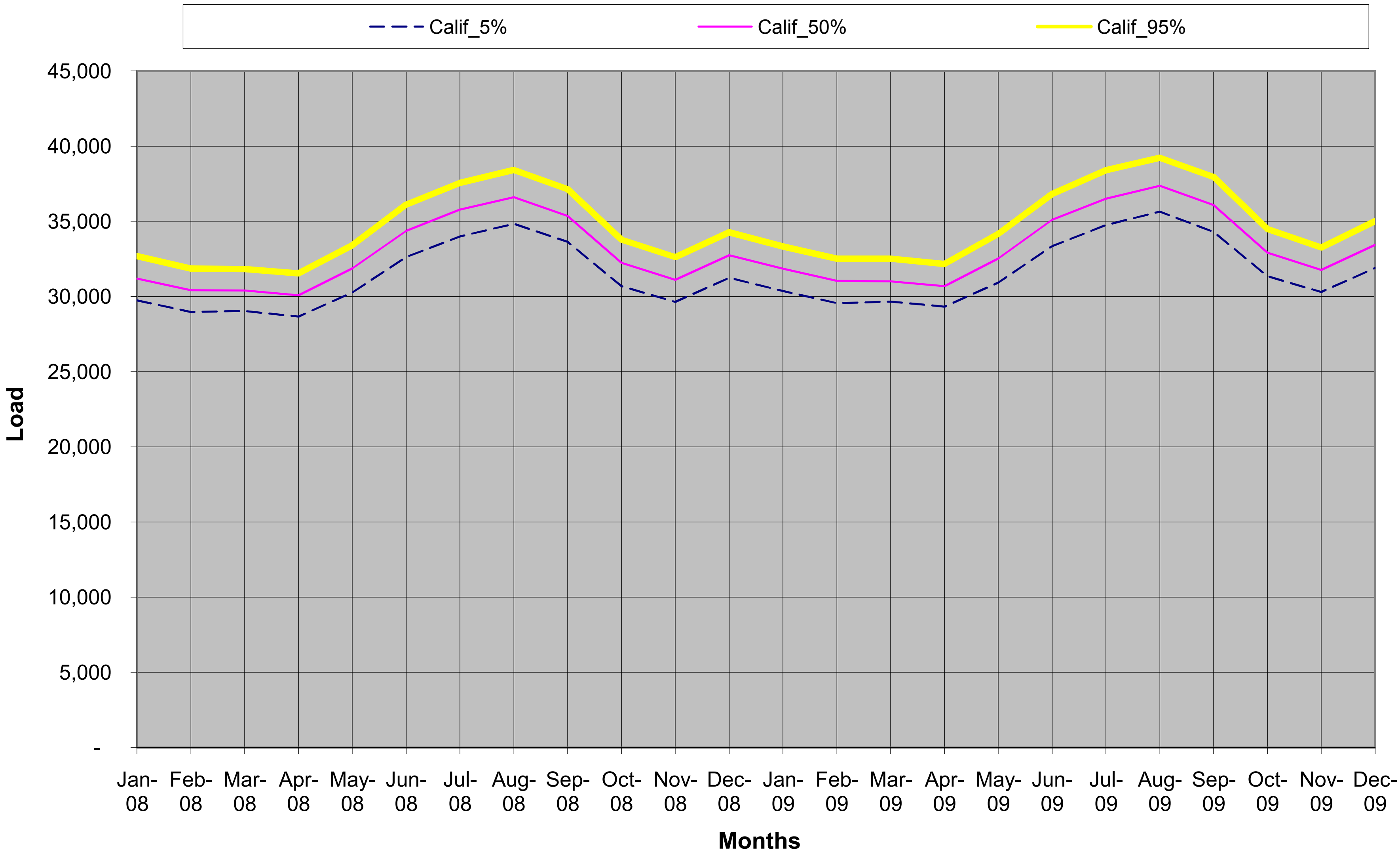
Calendar Year 2009

	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	Oct '09	Nov '09	Dec '09	Simple Avg
Average Annual California Loads (Average Energy in aMW)	33383	33383	33383	33383	33383	33383	33383	33383	33383	33383	33383	33383	
California Monthly Load Shapes (Source: AURORA)	**0.954**	**0.930**	**0.930**	**0.920**	**0.974**	**1.051**	**1.094**	**1.120**	**1.082**	**0.986**	**0.952**	**1.002**	
Simulated Monthly California Loads (Average Energy in aMW)	31850	31044	31044	30710	32517	35073	36523	37386	36108	32908	31769	33438	**33,364 aMW**

California Load Variability Due to Load Growth and Weather Uncertainty

	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	Oct '09	Nov '09	Dec '09	Simple Avg
California Loads after Load Growth (Average Energy in aMW)	31850	31044	31044	30710	32517	35073	36523	37386	36108	32908	31769	33438	**33,364 aMW**
Monthly Load Standard Deviation	1.46%	1.54%	1.48%	1.50%	1.70%	1.76%	1.76%	1.59%	1.88%	1.52%	1.50%	1.46%	
Random California Loads (Average Energy in aMW)	***31,850***	***31,044***	***31,044***	***30,710***	***32,517***	***35,073***	***36,523***	***37,386***	***36,108***	***32,908***	***31,769***	***33,438***	**33,364 aMW**

Graph 5: Simulated California Loads for CY 2008 - 2009
(Updated from WP-07 Initial Supplemental Proposal)



1.8.8 Use of Simulated California Loads in AURORA

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

1.9 Natural Gas Price Risk Factor

Natural gas price risk is incorporated into the Risk Analysis Study to account for the impact that natural gas price variability has on monthly HLH and LLH spot market electricity prices, which impacts BPA's surplus energy revenues and power purchase expenses. This impact is accounted for by inputting into AURORA the simulated monthly natural gas prices (in real 2000 dollars) from the Natural Gas Price Risk Model and having AURORA estimate the associated nominal monthly HLH and LLH spot market electricity prices for each simulation.

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

1.9.1 Inputs into the Natural Gas Price Risk Model

The Natural Gas Price Risk Model is designed to simulate variable natural gas prices based on natural gas prices used in AURORA to perform the Market Price Forecast Study (s*ee* FY 2009 Market Price Forecast Study, WP-07-FS-BPA-11). To accomplish this task, forecasted annual median delivered natural gas prices (in real 2000 dollars) to southern California for CY 2008-2009 and monthly gas price shape data (values relative to 1.00) from AURORA are input into the Natural Gas Price Risk Model. *Id.* With this data, the deterministic forecasted monthly prices in AURORA are calculated in the Natural Gas Price Risk Model by multiplying the annual median natural gas prices by the monthly gas price shapes. *Id.*

Additional information input into the Natural Gas Price Risk Model are minimum and maximum delivered natural gas price constraints (in real 2000 dollars) and monthly price volatilities for natural gas prices, which were derived from historical monthly spot market natural gas prices by computing the standard deviations of all the natural log (ln) price ratio changes from one month to the next month. These natural log price ratio changes (ln (price at time t/price at time t-1)) are commonly referred to as "returns" in the technical literature. Accordingly, they will be referred to as returns in this study.

Minimum and maximum delivered gas price constraints used in the Natural Gas Risk Model are \$1.50/MMBTU (Million British Thermal Units) and \$50.00/MMBTU. The minimum price constraint was set based on reviewing the historical real 2005 dollar prices at Ignacio, Colorado (*See* Table 21 in the FY 2009 Risk Analysis Study Documentation, WP-07-FS-BPA-12A) and adding an additional charge for delivery from Ignacio to southern California and the maximum price constraint was set such that no simulated prices would be constrained.

Historical monthly spot market gas prices in real 2005 dollars for Ignacio, Colorado, from December 1989 through December 2007 were used to calculate the monthly price volatilities for month-to-month price movements. Monthly price volatilities were estimated in terms of month-to-month price changes so that price movements through time could be modeled using the random-walk technique.

Table 21: Estimated Monthly Price Volatilities, Annual CY 2008 Price Volatility, and Annual CY 2008 Price Variability Based on the Gas Price Forecast (Updated from WP-07 Initial Supplemental Proposal)

Input Calculations for Gas Price Risk Model

Ignacio Monthly Spot Gas Prices in real 2005$

Dec-89	3.17												
	1	2	3	4	5	6	7	8	9	10	11	12	Annual
Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Average
1990	3.64	2.53	2.00	2.01	1.98	2.03	1.98	1.95	1.93	2.37	2.69	2.56	2.30
1991	2.19	1.58	1.38	1.43	1.39	1.36	1.38	1.47	1.67	1.69	2.24	2.24	1.67
1992	1.64	1.48	1.57	1.79	1.89	1.96	2.06	2.36	2.79	2.74	2.69	2.75	2.14
1993	2.57	2.20	2.67	2.51	2.34	2.17	2.30	2.47	2.59	2.36	2.48	2.57	2.44
1994	2.31	2.66	2.39	2.19	2.06	1.89	1.97	1.96	1.65	1.62	1.85	1.97	2.04
1995	1.57	1.36	1.35	1.39	1.42	1.40	1.24	1.48	1.55	1.45	1.51	1.55	1.44
1996	1.45	1.47	1.41	1.38	1.35	1.57	2.08	2.24	1.86	2.19	3.15	4.16	2.03
1997	4.17	2.86	1.89	2.03	2.24	2.32	2.40	2.65	3.08	3.25	3.47	2.54	2.74
1998	2.34	2.26	2.43	2.54	2.27	1.98	2.21	2.08	1.99	1.99	2.24	2.06	2.20
1999	2.04	1.90	1.75	2.06	2.32	2.35	2.34	2.76	2.75	2.91	2.60	2.57	2.36
2000	2.54	2.73	2.92	3.11	3.44	4.89	4.19	3.87	4.67	5.10	5.78	8.66	4.33
2001	9.06	6.30	5.34	5.10	3.91	2.96	2.70	2.83	2.03	2.32	2.43	2.51	3.96
2002	2.27	2.30	2.92	2.85	2.71	2.51	2.77	2.64	2.61	3.01	3.67	4.19	2.87
2003	4.76	5.49	5.68	3.78	4.76	5.19	4.79	4.85	4.47	4.49	4.29	5.60	4.85
2004	5.67	5.03	4.93	5.30	5.49	5.44	5.41	5.19	4.45	5.11	5.65	6.22	5.32
2005	5.53	5.54	6.27	6.39	5.62	5.77	6.22	7.42	8.99	10.17	7.41	11.27	7.22
2006	7.15	6.36	5.57	5.60	4.93	5.28	5.39	6.33	4.14	5.08	5.61	6.24	5.64
2007	5.85	6.61	5.80	6.32	6.34	6.17	5.19	5.24	4.93	5.88	5.09	6.11	5.79
Annual Average	3.71	3.37	3.24	3.21	3.14	3.18	3.15	3.32	3.23	3.54	3.60	4.21	3.41
Median	2.55	2.59	2.55	2.53	2.33	2.33	2.37	2.65	2.68	2.82	2.92	2.66	2.59
Annual Standard Deviation													1.71

Ignacio Monthly Spot Gas Price Natural Log (Ln) Ratio Deltas (Returns) and Volatility Computations; Reflects Month-To-Month Price Changes

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1990	0.14	-0.37	-0.23	0.00	-0.02	0.02	-0.02	-0.02	-0.01	0.21	0.13	-0.05
1991	-0.16	-0.33	-0.13	0.04	-0.03	-0.02	0.02	0.06	0.12	0.01	0.28	0.00
1992	-0.31	-0.10	0.06	0.13	0.05	0.04	0.05	0.13	0.17	-0.02	-0.02	0.02
1993	-0.07	-0.15	0.19	-0.06	-0.07	-0.08	0.05	0.07	0.05	-0.09	0.05	0.03
1994	-0.10	0.14	-0.11	-0.09	-0.06	-0.08	0.04	-0.01	-0.17	-0.02	0.13	0.06
1995	-0.22	-0.14	-0.01	0.03	0.02	-0.01	-0.12	0.18	0.05	-0.07	0.04	0.02
1996	-0.07	0.01	-0.04	-0.02	-0.02	0.15	0.28	0.08	-0.19	0.16	0.36	0.28
1997	0.00	-0.38	-0.42	0.07	0.10	0.03	0.03	0.10	0.15	0.05	0.07	-0.31
1998	-0.08	-0.03	0.07	0.05	-0.11	-0.14	0.11	-0.06	-0.04	0.00	0.12	-0.09
1999	-0.01	-0.07	-0.08	0.16	0.12	0.01	-0.01	0.16	0.00	0.05	-0.11	-0.01
2000	-0.01	0.07	0.07	0.06	0.10	0.35	-0.15	-0.08	0.19	0.09	0.12	0.40
2001	0.05	-0.36	-0.17	-0.05	-0.26	-0.28	-0.09	0.05	-0.33	0.13	0.04	0.03
2002	-0.10	0.01	0.24	-0.02	-0.05	-0.08	0.10	-0.05	-0.01	0.14	0.20	0.13
2003	0.13	0.14	0.03	-0.41	0.23	0.09	-0.08	0.01	-0.08	0.00	-0.05	0.27
2004	0.01	-0.12	-0.02	0.07	0.04	-0.01	-0.01	-0.04	-0.15	0.14	0.10	0.10
2005	-0.12	0.00	0.12	0.02	-0.13	0.03	0.07	0.18	0.19	0.12	-0.32	0.42
2006	-0.46	-0.12	-0.13	0.00	-0.13	0.07	0.02	0.16	-0.42	0.20	0.10	0.11
2007	-0.06	0.12	-0.13	0.09	0.00	-0.03	-0.17	0.01	-0.06	0.18	-0.14	0.18
Volatilities (Std Devs of Ln Ratio Deltas)	0.144	0.173	0.158	0.121	0.113	0.127	0.108	0.086	0.174	0.093	0.156	0.177
Average of Ln Ratio Deltas	-0.08	-0.09	-0.04	0.00	-0.01	0.00	0.01	0.05	-0.03	0.07	0.06	0.09

Cumulative Monthly Price Standard Deviation Computations for Gas Price Forecast Made at the Beginning of the Current Calendar Year (Impacted by Both Price Level and Volatility)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Avg
CY08 Price Forecast (Median)	6.41	6.63	7.14	7.72	7.53	9.06	7.04	6.76	6.55	6.13	6.16	6.35	6.96
CY08 Computed Average Prices	6.47	6.77	7.43	7.96	7.85	9.58	7.57	7.25	7.29	6.86	6.91	7.55	7.46

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
1990	7.97	6.28	5.69	6.27	6.04	7.70	5.45	4.80	4.70	4.95	5.31	4.82	5.83
1991	5.94	4.91	4.99	5.73	5.43	6.81	4.86	4.63	5.21	4.49	5.62	5.33	5.33
1992	5.10	5.27	6.31	7.74	8.08	9.90	8.32	8.73	10.46	9.11	8.45	8.10	7.96
1993	6.48	6.32	8.48	8.52	7.85	8.78	7.20	7.06	7.43	5.87	5.83	5.71	7.13
1994	6.26	8.11	8.09	7.95	7.38	8.29	6.58	5.91	4.92	4.07	4.40	4.49	6.37
1995	5.55	5.49	6.15	6.92	6.92	8.35	5.33	5.75	6.01	4.81	4.73	4.62	5.89
1996	6.50	7.46	7.93	8.33	8.08	10.84	12.27	12.27	10.29	10.85	14.69	17.98	10.63
1997	6.96	5.46	4.26	5.13	5.54	7.24	5.42	5.40	6.28	5.72	5.77	4.06	5.60
1998	6.40	7.02	8.32	9.26	8.18	8.63	7.55	6.46	6.19	5.32	5.67	4.95	7.00
1999	6.90	7.27	7.46	9.31	10.44	12.06	9.89	10.78	10.90	10.28	8.69	8.03	9.34
2000	6.87	8.32	9.78	10.94	12.06	18.58	13.82	11.82	14.50	14.32	15.28	21.13	13.12
2001	7.27	5.77	5.59	5.89	4.39	4.83	2.37	2.07	1.32	0.98	1.00	1.14	3.55
2002	6.28	7.19	10.02	10.32	9.72	10.50	9.47	8.30	8.24	8.43	9.68	10.33	9.04
2003	7.89	10.19	11.47	8.19	10.24	12.64	9.57	8.92	8.28	7.31	6.58	8.07	9.11
2004	7.04	7.06	7.71	8.82	9.06	10.47	8.32	7.29	6.24	6.25	6.52	6.76	7.63
2005	6.19	7.01	8.75	9.47	8.23	9.95	8.63	9.48	11.65	11.83	8.14	11.52	9.24
2006	4.41	4.52	4.63	5.21	4.45	6.27	4.35	4.55	2.87	2.85	2.99	3.24	4.19
2007	6.52	8.29	8.07	9.33	9.28	10.53	6.79	6.21	5.82	6.04	4.95	5.63	7.29
CY08 Cumulative Price Std Dev	0.883	1.433	1.978	1.752	2.124	3.028	2.839	2.722	3.290	3.372	3.591	5.054	2.362

Cumulative Monthly Volatility Computations for Gas Price Forecast Made at the Beginning of the Current Calendar Year

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual (LN)
1990	0.22	-0.05	-0.23	-0.21	-0.22	-0.16	-0.26	-0.34	-0.33	-0.21	-0.15	-0.28	1.76
1991	-0.08	-0.30	-0.36	-0.30	-0.33	-0.28	-0.37	-0.38	-0.23	-0.31	-0.09	-0.18	1.67
1992	-0.23	-0.23	-0.12	0.00	0.07	0.09	0.17	0.26	0.47	0.40	0.32	0.24	2.07
1993	0.01	-0.05	0.17	0.10	0.04	-0.03	0.02	0.04	0.13	-0.04	-0.05	-0.11	1.96
1994	-0.02	0.20	0.12	0.03	-0.02	-0.09	-0.07	-0.13	-0.29	-0.41	-0.33	-0.35	1.85
1995	-0.14	-0.19	-0.15	-0.11	-0.08	-0.08	-0.28	-0.16	-0.09	-0.24	-0.26	-0.32	1.77
1996	0.01	0.12	0.10	0.08	0.07	0.18	0.55	0.60	0.45	0.57	0.87	1.04	2.36
1997	0.08	-0.19	-0.52	-0.41	-0.31	-0.22	-0.26	-0.22	-0.04	-0.07	-0.07	-0.45	1.72
1998	0.00	0.06	0.15	0.18	0.08	-0.05	0.07	-0.05	-0.06	-0.14	-0.08	-0.25	1.95
1999	0.07	0.09	0.04	0.19	0.33	0.29	0.34	0.47	0.51	0.52	0.35	0.23	2.23
2000	0.07	0.23	0.31	0.35	0.47	0.72	0.67	0.56	0.79	0.85	0.91	1.20	2.57
2001	0.13	-0.14	-0.25	-0.27	-0.54	-0.63	-1.09	-1.18	-1.60	-1.83	-1.82	-1.72	1.27
2002	-0.02	0.08	0.34	0.29	0.26	0.15	0.30	0.21	0.23	0.32	0.45	0.49	2.20
2003	0.21	0.43	0.47	0.06	0.31	0.33	0.31	0.28	0.23	0.18	0.07	0.24	2.21
2004	0.09	0.06	0.08	0.13	0.19	0.14	0.17	0.08	-0.05	0.02	0.06	0.06	2.03
2005	-0.04	0.06	0.20	0.20	0.09	0.09	0.20	0.34	0.58	0.66	0.28	0.60	2.22
2006	-0.38	-0.38	-0.43	-0.39	-0.53	-0.37	-0.48	-0.39	-0.83	-0.77	-0.72	-0.67	1.43
2007	0.02	0.22	0.12	0.19	0.21	0.15	-0.04	-0.08	-0.12	-0.01	-0.22	-0.12	1.99
Cumulative Volatilities	0.144	0.211	0.278	0.234	0.289	0.300	0.416	0.428	0.557	0.611	0.604	0.656	0.326

1.9.2 Modeling Natural Gas Price Volatility and Variability

Statistical parameters needed to quantify risk in probability distributions in the Natural Gas Price Risk Model are developed from the Ignacio price data. This quantification allows the volatility in the historical natural gas price data for Ignacio to be incorporated into the Natural Gas Price Risk Model. This process is performed in the following manner: (1) all the returns from one month to the next month for all months from December 1989 through December 2007 are calculated; (2) all the returns are accumulated, by month, for each of the 12 months in a year; and (3) the standard deviation of all the returns from one month to the next month for each month are calculated. This process results in monthly price volatilities being calculated from a set of 18 price changes for all months of the year. Using a similar approach with annual price data, cumulative annual price volatilities over several years duration were computed to quantify how much annual prices could deviate in the future from the current natural gas price forecast.

Table 21 contains the historical Ignacio monthly spot market natural gas prices, the calculations of the month-to-month returns, and the derivation of the monthly price volatilities. Comparisons between the average and median prices for the monthly and annual historical price data indicate that average prices are greater than median prices. Additional comparisons indicate that the differences between the maximum prices and the median prices are greater than the differences between the minimum prices and the median prices. These asymmetrical differences were accounted for in this study by modeling natural gas price risk in lognormal probability distributions that differ in skewness depending on the size of the differences.

A comparison of the month-to-month volatilities in Table 21 reveals that, in general, month-to-month price movements, either upward or downward, are greatest during the wintertime. At the bottom of this table, the month-to-month returns are applied to the CY 2008 natural gas price forecast to compute monthly price variability, annual price variability, and the annual price volatility for CY 2008. As the values in this table indicate, price variability (as measured by standard deviation) is impacted by both the volatility and the price level with price variability increasing the higher the volatility and/or the price level.

The results reported in Table 21 indicate that monthly and annual price variability at forecasted CY 2008 prices are substantial with annual CY 2008 price variability being $2.36/MMBTU, which translates into an annual price volatility of 32.6 percent. These results reflect how much natural gas prices can vary from a gas price forecast made at the beginning of CY 2008. Natural gas price variability was turned off in the Natural Gas Price Risk Model for the months of January thru June of 2008 to account for the fact that there is less natural gas price risk for the remainder of the year than for a full year.

Table 22 contains the calculations of the cumulative annual price returns for one year after the current calendar year (CY 2009) and the derivation of the associated cumulative annual price volatility. The cumulative annual price returns for CY 2009 were derived by computing all the annual price returns over a one year period and calculating the associated standard deviation to get the cumulative annual price volatility. This value was computed so that the simulated prices over time would have a value to calibrate to, rather than move through time in an unconstrained manner. The cumulative annual price volatility for CY 2009 was calculated to be 30.2 percent.

At the bottom of Table 22, the cumulative annual price returns for CY 2009 were applied to the CY 2009 natural gas price forecast to compute the cumulative annual price variability. This price variability (as measured by standard deviation) is impacted by both the volatility and the price level with price variability increasing the higher the volatility and/or the price level.

Monthly gas price variability was incorporated into the Natural Gas Price Risk Model by sampling positive and negative standard deviation values from truncated standard normal probability distributions in @RISK, multiplying the sampled standard deviation values by monthly price volatility values, and multiplying the natural gas price of the prior month by the exponential of the simulated positive and negative values (which transforms values that are in terms of natural logs into unlogged values). A truncated standard normal distribution is a normal distribution having a mean of zero, a standard deviation of one, and a specified maximum and minimum value that sets an upper and lower bound on the standard deviation values that can be sampled. For this study, the specified maximum and minimum values were set at +5 and -5 standard deviations (which results in them having no impact), since controlling the maximum and minimum standard deviations was not needed.

In the @RISK computer software, this information is entered into a truncated standard normal probability distribution (RiskTNormal) as follows:

RiskTNormal (Mean = 0, Standard deviation = 1, Min value = -5, Max value = +5).

Under this methodology, the positive and negative values sampled from the truncated standard normal distributions are the number of standard deviations of a random price movement. The standard deviations sampled from the monthly truncated standard normal distributions in the Natural Gas Price Risk Model are multiplied by the monthly volatilities as part of the price movement computations reported in the equation below.

<u>Prices movements through time are modeled as follows:</u>

Price t = Price t-1 * EXP (Sampled positive or negative standard deviation * monthly volatility) + (FP t minus FP t-1)

Where:
Price t = Simulated price at time t
Price t-1 = Simulated price at time t-1
FP t = Forecasted price for time t
FP t-1 = Forecasted price for time t-1
EXP = Exponential Function (used to take the antilog of the returns; which are in logs)

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

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

Sampled positive or negative standard deviation = RiskTNormal (Mean-reversion decay parameters * (1 - Simulated mean-reversion ratios), 1, Maximum negative monthly standard deviation, Maximum positive monthly standard deviation)

Where:
RiskTNormal = Truncated normal probability distribution in @RISK with
Mean = Mean-reversion decay parameters * (1- Simulated mean-reversion ratios)
Standard deviation = 1
Minimum value = - 5 standard deviations
Maximum value = + 5 standard deviations
Mean-reversion decay parameters = Calibrated price decay values
Simulated mean-reversion ratios = LN(Simulated prior month price) / LN(Forecasted prior month price)
LN = Natural log function in Excel

Table 22: Estimated CY 2009 Price Statistics Based on Applying Historical Volatility to the Gas Price Forecast (Updated from WP-07 Initial Supplemental Proposal)

		Annual Gas Price Forecast
		CY09
		5.76

Ignacio Annual Spot Gas Price Natural Log (Ln) Ratio Deltas (Returns) and Volatility Computations

Year	Annual Average Historical Real Prices	1 Yr LN Ratio Changes
1990	2.30	
1991	1.67	-0.32
1992	2.14	0.25
1993	2.44	0.13
1994	2.04	-0.18
1995	1.44	-0.35
1996	2.03	0.34
1997	2.74	0.30
1998	2.20	-0.22
1999	2.36	0.07
2000	4.33	0.61
2001	3.96	-0.09
2002	2.87	-0.32
2003	4.85	0.52
2004	5.32	0.09
2005	7.22	0.30
2006	5.64	-0.25
2007	5.79	0.03
Volatilities (Std Devs of Ln Ratio Deltas)		0.302

Annual Gas Price Standard Deviation for Gas Price Forecast Based on Historical Volatility

Year		CY09
1990		
1991		3.95
1992		7.02
1993		6.20
1994		4.58
1995		3.85
1996		7.67
1997		7.39
1998		4.38
1999		5.86
2000		10.00
2001		5.00
2002		3.96
2003		9.22
2004		6.00
2005		7.40
2006		4.27
2007		5.61
Standard Deviation		1.87

1.9.3 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 is 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.

BPA used the statistical approach of minimizing the sum of residuals squared to help objectively determine the relative merits of one set of decay values versus another. The sum of residuals squared is calculated by squaring the differences between historical monthly and annual natural gas price volatilities and simulated monthly and annual natural gas price volatilities and summing these squared differences. The lower the sum of residuals squared, the better the simulated gas price volatilities approximate the historical gas price volatilities. Table 23 contains the final calibration results for natural gas price volatility along with additional summary statistical information.

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

Table 23: Natural Gas Price Volatility Calibration
(Updated from WP-07 Initial Supplemental Proposal)

Mean-Reversion Calibration Section:

CY 2008	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean Reversion Rate	0.315	0.315	0.315	0.315	0.315	0.315	0.315	0.315	0.315	0.315	0.315	0.315
Max/Min Std Dev.	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000

CY 2009	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Mean Reversion Rate	1.190	1.190	1.190	1.190	1.190	1.190	1.190	1.190	1.190	1.190	1.190	1.190
Max/Min Std Dev.	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000	5.000

Volatility Reporting & Calibration Section:

	Sum 08-09	CY 2008	CY 2009
Simulated Price Volatilities for FY08-09		0.304	0.302
Historical Price Volatilities Over 1, 2, and 3 Year Periods		0.326	0.302
Simulated Less Historical Volatilities		-0.022	0.000
Residual ^2	0.0005	0.000	0.000

Statistical Reporting Section:

	Sum 08-09	CY 2008	CY 2009
Simulated FY08-09 Price Standard Deviations		2.372	1.862
Estimated FY08-09 Price Standard Deviations; Derived By Applying Historical Price Volatilities to the Price Forecast		2.362	2.099
Simulated Less Estimated Standard Deviations		0.009	-0.237
Residual ^2	0.0563	0.000	0.056

	Avg 08-09	CY 2008	CY 2009
Simulated Average Price	6.46	7.43	6.09
Simulated Median Price	6.12	7.06	5.89
Simulated Average Minus Median Price	0.34	0.37	0.20
Average Minus Median Prices; Derived By Applying Historical Price Volatilities to the Price Forecast	0.35	0.50	0.30
Gas Price Forecast	6.01	6.96	5.76
Simulated Average Price Less Forecast Price	0.44	0.48	0.32
Simulated Median Price Less Forecast Price	0.11	0.10	0.12

CY 2008	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Simulated Cumulative Monthly Price Volatilities	0.144	0.219	0.253	0.260	0.294	0.265	0.372	0.402	0.456	0.505	0.529	0.538	0.304
Historical Cumulative Monthly Price Volatilities	0.144	0.211	0.278	0.234	0.289	0.300	0.416	0.428	0.557	0.611	0.604	0.656	0.326
Simulated Less Historical Monthly Price Volatilies	0.000	0.008	-0.025	0.026	0.005	-0.035	-0.044	-0.026	-0.101	-0.106	-0.075	-0.118	-0.022
Residual ^2	0.0000	0.0001	0.0006	0.0007	0.0000	0.0012	0.0019	0.0007	0.0103	0.0113	0.0056	0.0139	0.0005
Sum of Squares	0.0463												0.0005
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Simulated Cumulative Monthly Price Standard Deviations	0.940	1.519	1.944	2.170	2.402	2.641	2.881	2.999	3.409	3.529	3.794	4.091	2.372
Estimated Cumulative Price Std Devs; Derived From Historical LN Price Changes and tl	0.883	1.433	1.978	1.752	2.124	3.028	2.839	2.722	3.290	3.372	3.591	5.054	2.362
Simulated Less Estimated Price Standard Deviations	0.057	0.085	-0.035	0.418	0.278	-0.386	0.041	0.278	0.120	0.157	0.203	-0.963	0.009
Residual ^2	0.0033	0.0073	0.0012	0.1744	0.0771	0.1493	0.0017	0.0770	0.0143	0.0246	0.0413	0.9271	0.0001
Sum of Squares	1.4987												0.0001

1.9.4 Model and Results

Table 24 contains a copy of the Natural Gas Price Risk Model. Results from this risk model on a monthly basis over time are shown in Graph 6 for the 5th, 50th, and 95th percentiles. As can be noted in this graph, gas price variability started being simulated in July 2008. This was the first month that prices were forecasted in the Natural Gas Price Forecast. The monthly natural gas price variability patterns shown in this graph for CY 2008-2009 reflect the computations previously calculated in Table 21, which indicate that gas price volatility, in general, is highest during the winter.

The prices in Graph 6 include month-specific price level adjustments during CY 2008-CY 2009 that perfectly align the median monthly simulated gas prices to the monthly prices in the natural gas price forecast. These adjustments were made based on median prices rather than average simulated prices because BPA's natural gas price forecast represents its assessment that there is a 50 percent probability that natural gas prices could go higher or lower than its forecast. *See* Petty, *et al.*, WP-07-E-BPA-11. Because each of these monthly price level adjustments is applied to all simulated prices for that month, such adjustments do not alter the simulated price volatility values.

Table 24: Natural Gas Price Risk Model
(Updated from WP-07 Initial Supplemental Proposal)

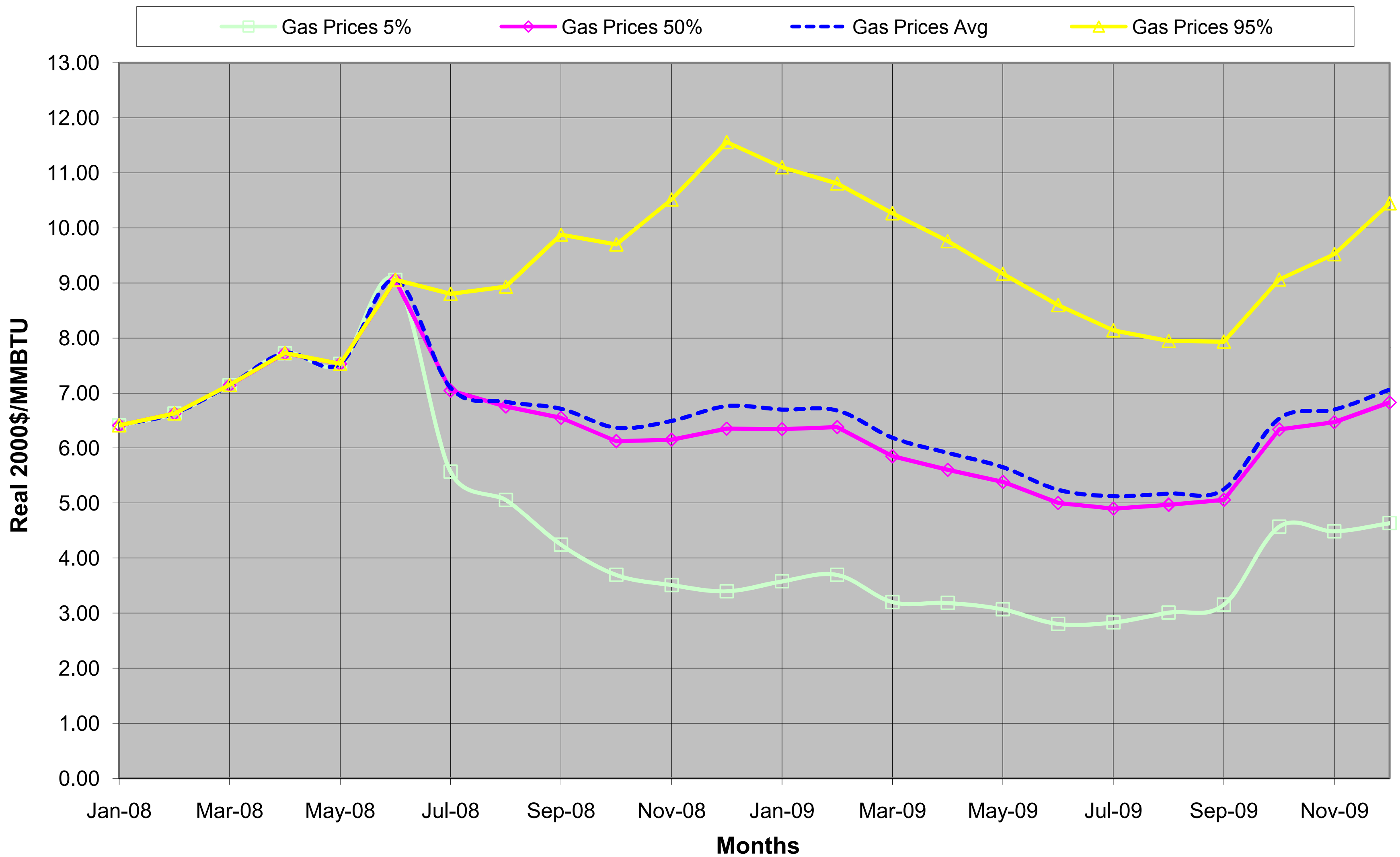
Forecasted Real 2000$ Delivered Natural Gas Prices Per MMBTU to Southern California

CY 2008 Avg $ 6.96
CY 2009 Avg $ 5.76

CY07-09 Avg $ 6.36

	Price Forecast ($/MMBTU)	Standard Normal Truncated Distribution N(var mean, 1); Includes Max and Min Std Devs	Monthly Volatility	Price Risk ($/MMBTU)	Standard Normal Distribution Mean Adjustor (Causes Mean Reversion)	Actuals		Monthly Volatility	Mean Reversion Decay Parameters	Maximum and Minimum Standard Deviations	Monthly Gas Price Shapes	Price Forecast ($/MMBTU)	Minimum Price ($/MMBTU)	Maximum Price ($/MMBTU)	Unconstrained Simulated Prices ($/MMBTU)
Initial Value					1.00										
Jan-08	6.41	0.00	0.144	6.41	1.00	Y	Jan-08	0.144	0.00	5.00	0.92	6.41	1.50	50.00	6.41
Feb-08	6.63	0.00	0.173	6.63	1.00	Y	Feb-08	0.173	0.00	5.00	0.95	6.63	1.50	50.00	6.63
Mar-08	7.14	0.00	0.158	7.14	1.00	Y	Mar-08	0.158	0.00	5.00	1.03	7.14	1.50	50.00	7.14
Apr-08	7.72	0.00	0.121	7.72	1.00	Y	Apr-08	0.121	0.00	5.00	1.11	7.72	1.50	50.00	7.72
May-08	7.53	0.00	0.113	7.53	1.00	Y	May-08	0.113	0.00	5.00	1.08	7.53	1.50	50.00	7.53
Jun-08	9.06	0.00	0.127	9.06	1.00	Y	Jun-08	0.127	0.00	5.00	1.30	9.06	1.50	50.00	9.06
Jul-08	7.04	0.00	0.108	7.04	1.00	N	Jul-08	0.108	0.00	5.00	1.01	7.04	1.50	50.00	7.04
Aug-08	6.76	0.00	0.086	6.76	1.00	N	Aug-08	0.086	0.00	5.00	0.97	6.76	1.50	50.00	6.76
Sep-08	6.55	0.00	0.174	6.55	1.00	N	Sep-08	0.174	0.00	5.00	0.94	6.55	1.50	50.00	6.55
Oct-08	6.13	0.00	0.093	6.13	1.00	N	Oct-08	0.093	0.00	5.00	0.88	6.13	1.50	50.00	6.13
Nov-08	6.16	0.00	0.156	6.16	1.00	N	Nov-08	0.156	0.00	5.00	0.88	6.16	1.50	50.00	6.16
Dec-08	6.35	0.00	0.177	6.35	1.00	N	Dec-08	0.177	0.00	5.00	0.91	6.35	1.50	50.00	6.35
Jan-09	6.35	0.00	0.144	6.35	1.00		Jan-09	0.144	1.92	5.00	1.10	6.35	1.50	50.00	6.35
Feb-09	6.38	0.00	0.173	6.38	1.00		Feb-09	0.173	1.92	5.00	1.11	6.38	1.50	50.00	6.38
Mar-09	5.85	0.00	0.158	5.85	1.00		Mar-09	0.158	1.92	5.00	1.02	5.85	1.50	50.00	5.85
Apr-09	5.61	0.00	0.121	5.61	1.00		Apr-09	0.121	1.92	5.00	0.97	5.61	1.50	50.00	5.61
May-09	5.39	0.00	0.113	5.39	1.00		May-09	0.113	1.92	5.00	0.93	5.39	1.50	50.00	5.39
Jun-09	5.00	0.00	0.127	5.00	1.00		Jun-09	0.127	1.92	5.00	0.87	5.00	1.50	50.00	5.00
Jul-09	4.90	0.00	0.108	4.90	1.00		Jul-09	0.108	1.92	5.00	0.85	4.90	1.50	50.00	4.90
Aug-09	4.97	0.00	0.086	4.97	1.00		Aug-09	0.086	1.92	5.00	0.86	4.97	1.50	50.00	4.97
Sep-09	5.06	0.00	0.174	5.06	1.00		Sep-09	0.174	1.92	5.00	0.88	5.06	1.50	50.00	5.06
Oct-09	6.34	0.00	0.093	6.34	1.00		Oct-09	0.093	1.92	5.00	1.10	6.34	1.50	50.00	6.34
Nov-09	6.47	0.00	0.156	6.47	1.00		Nov-09	0.156	1.92	5.00	1.12	6.47	1.50	50.00	6.47
Dec-09	6.83	0.00	0.177	6.83	1.00		Dec-09	0.177	1.92	5.00	1.19	6.83	1.50	50.00	6.83

Graph 6: Simulated Natural Gas Prices for 2008 - 2009
(Updated from WP-07 Initial Supplemental Proposal)



1.9.5 Use of Simulated Natural Gas Prices in AURORA

The spot market electricity price impacts associated with changes in natural gas prices are estimated in the AURORA model by inputting real monthly gas price data simulated by the Natural Gas Price Risk Model. From each simulation of monthly southern California natural gas prices (in real 2000 dollars), annual average gas prices and monthly gas price ratios (monthly gas prices divided by annual average gas prices) are derived. From this data, simulated monthly and annual gas prices are derived for each of the 13 regions that represent the WECC region in the AURORA Model. This task is accomplished by adding deterministic positive/negative annual average price basis differences for each of the remaining 12 regions modeled in AURORA to the simulated annual average delivered natural gas prices for southern California to get simulated annual average natural gas prices for all 13 regions. Monthly natural gas prices for each of the remaining 12 regions are derived by using the simulated monthly gas price ratios for southern California to yield simulated monthly natural gas prices for all 13 regions (*see* FY 2009 Market Price Forecast Study, WP-07-FS-BPA-11, for further discussion of AURORA).

1.10 Nuclear Plant Generation Risk Factor

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

1.10.1 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 FY 2009 Load Resource Study, WP-07-FS-BPA-09. 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 FY 2009 Load Resource Study, WP-07-FS-BPA-09.

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.

1.10.2 Model and Results

Table 25 contains a copy of the CGS Nuclear Plant Risk Model. The simulated frequency distribution for CGS output for October 2008 is shown in Graph 7.

Table 25: CGS Nuclear Plant Risk Model
(Updated from WP-07 Initial Supplemental Proposal)

	H Factor:	Capacity
CGS Input Parameters	19.93	1162

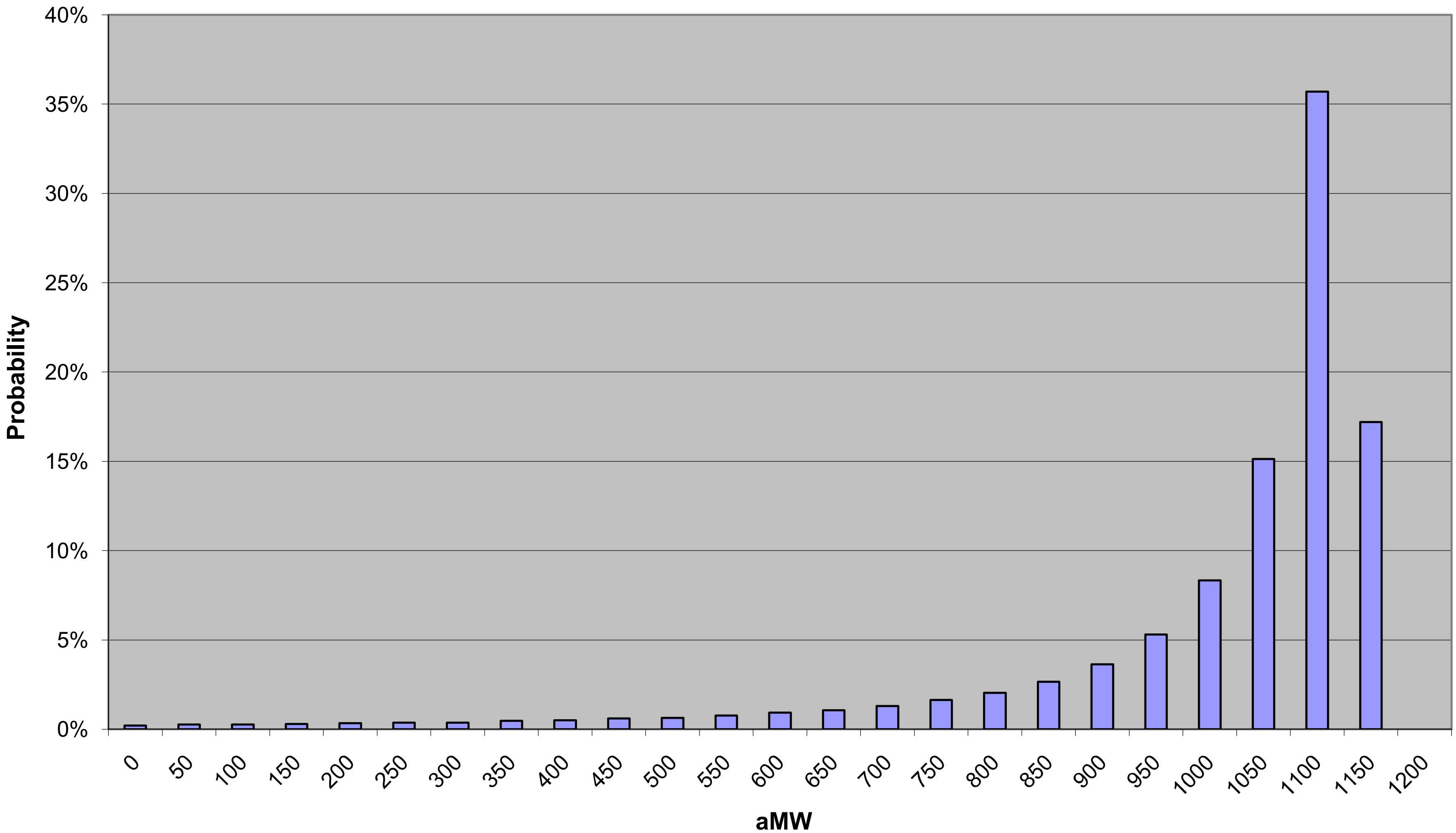
CY 2008

	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Oct '08	Nov '08	Dec '08
Simulated CGS Output (aMW)	1106	1106	1106	1106	1106	1106	1106	1106	1106	1106	1106	1106
CGS L&R Study (Average Energy in aMW)	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030
Simulated Mean Values	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030	1030
Risk Uniform Distribution	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*

CY 2009

	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	Oct '09	Nov '09	Dec '09
Simulated CGS Output (aMW)	1106	1106	1106	1106	286	0	1071	1106	1106	1106	1106	1106
CGS L&R Study (Average Energy in aMW)	1030	1030	1030	1030	266	0	997	1030	1030	1030	1030	1030
Simulated Mean Values	1030	1030	1030	1030	266	0	997	1030	1030	1030	1030	1030
Risk Uniform Distribution	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*	*0.5*

Graph 7: Simulated CGS Output Distribution for October 2008
(Updated from WP-07 Initial Supplemental Proposal)



1.11 Investor Owned Utility (IOU) Benefits Risk Factor

In the WP-07 Final Proposal, the variability of the Investor Owned Utility (IOU) Residential Exchange Program (REP) settlement benefits was modeled in the ToolKit. This was necessary because the IOU REP settlement benefits depended in part on a proxy for the market price of power, and since that could not be known in advance, there was financial uncertainty for BPA.

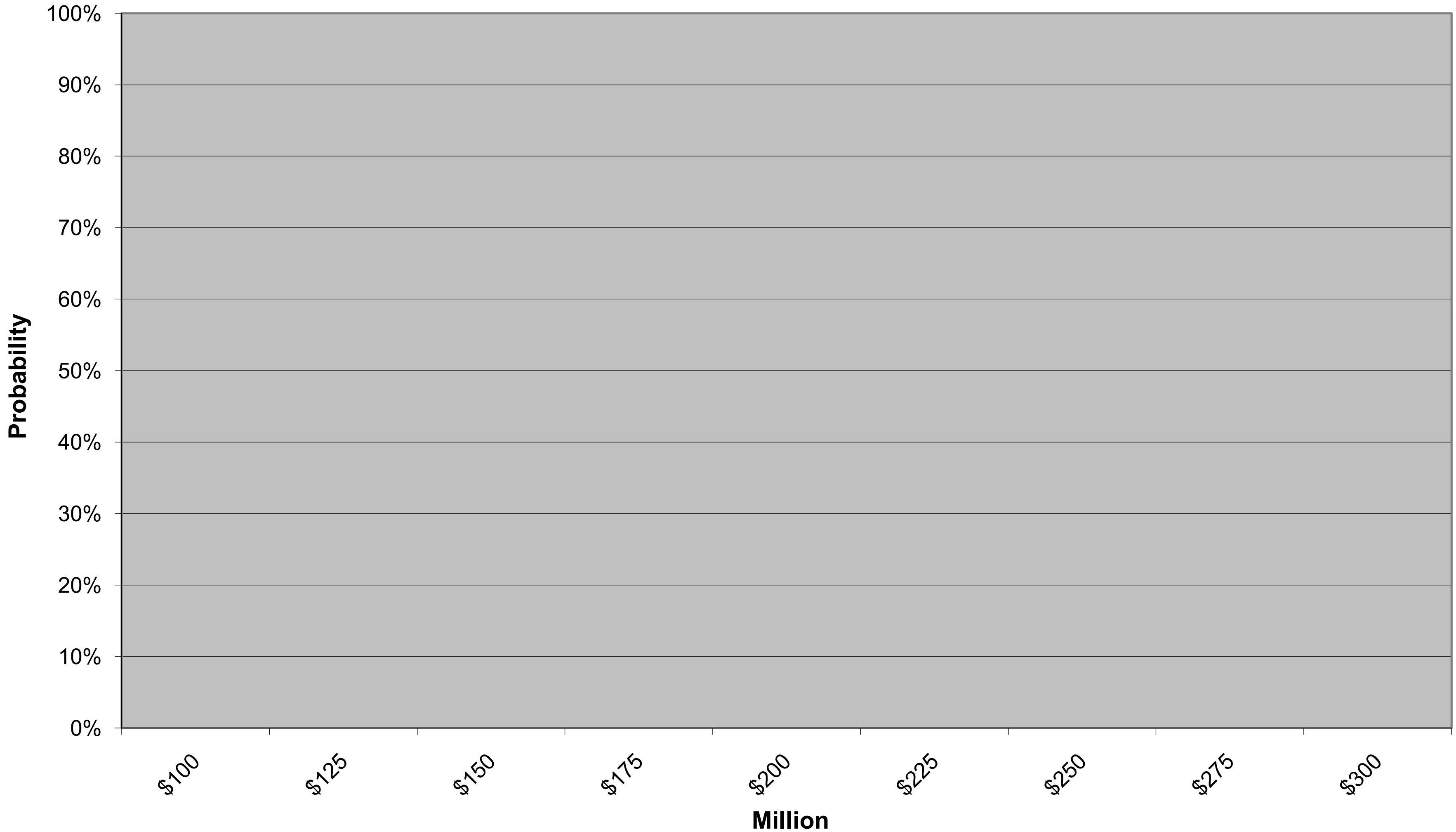
BPA is replacing the IOU REP settlements after they were overturned by the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit or Court). The replacement Residential Exchange Program does not create as much financial uncertainty for BPA. Most of the variability around IOU net REP benefit levels will be eliminated through how BPA is proposing to treat the Lookback amounts. *See* Marks, *et al.*, WP-07-E-BPA-62.

1.11.1 Data and Modeling Methodology

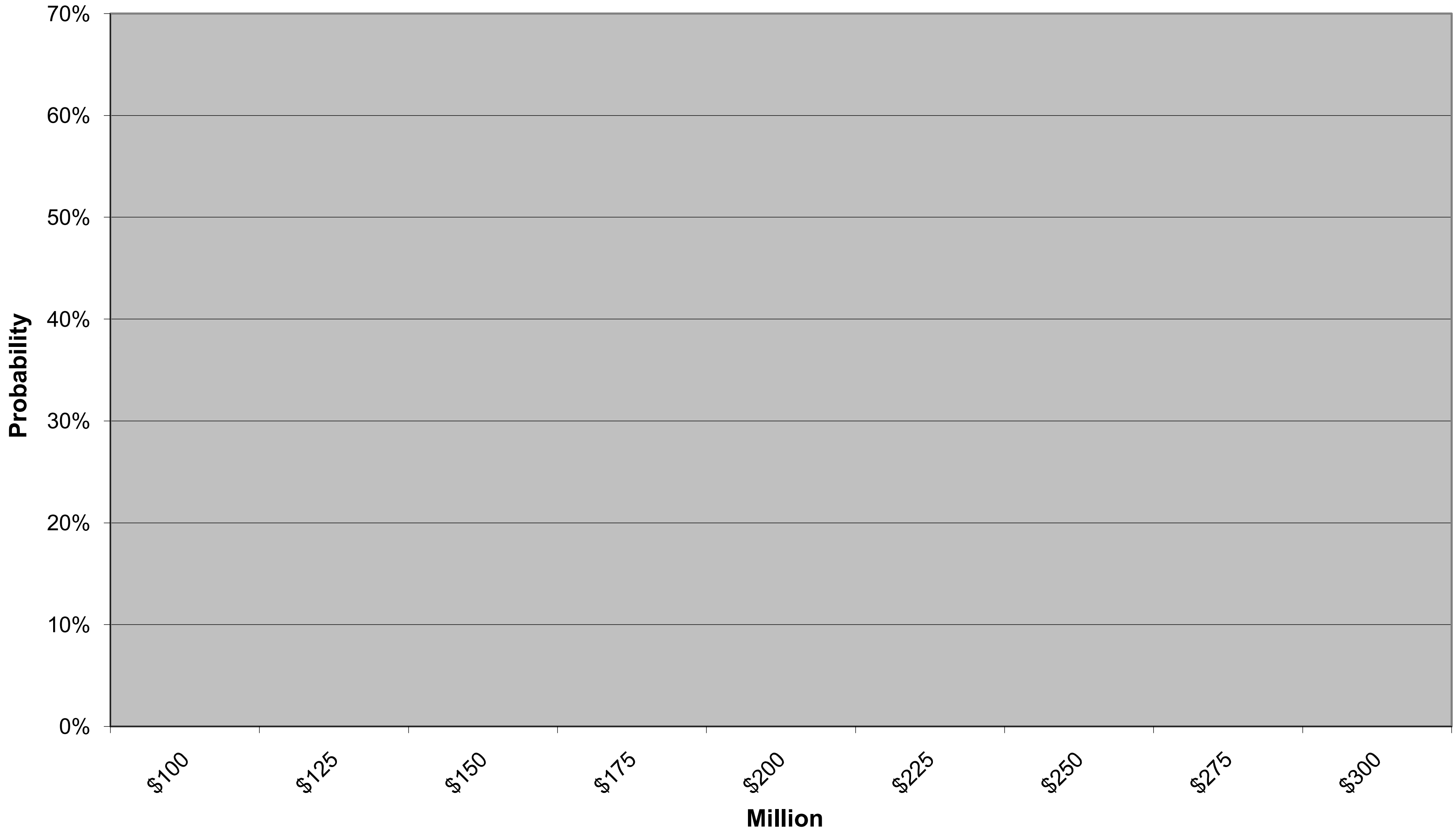
1.11.2 Results

Graphs 8-9 are not applicable to the Supplemental Proposal.

Graph 8: IOU Benefit Distribution for FY 2008
(This graph is not applicable to the WP-07 Final Supplemental Proposal)



Graph 9: IOU Benefit Distribution for FY 2009
(This graph is not applicable to the WP-07 Final Supplemental Proposal)



1.12 Direct Service Industry (DSI) Benefits Risk Factor

This risk factor reflects the uncertainty in the amount of DSI benefit payments in FY 2009, relative to the benefits included in the Revenue Requirement when setting rates. (*See* FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10**.)** The quantification of this risk reflects the service terms set forth in the BPA Service to DSI Customers for Fiscal Years 2007-2011, Administrator's Record of Decision, signed June 30, 2005 (DSI ROD), and the DSI Supplemental Administrator's Record of Decision, signed May 31, 2006 (DSI Supplemental ROD), which includes providing 560 aMW of financial benefits to the aluminum company DSIs and an FPS sale of 17 aMW to the Port Townsend Paper Company via its local PUD at the lowest-cost flat PF rate. The DSI Benefit risk is modeled in the DSI Benefit Risk Model, while service to Port Townsend is modeled in RevSim.

Since DSI contracts were executed in 2006, the following three things have occurred that impact the amount and risk of DSI benefit payments: (1) All three aluminum DSI Customers selected the 5-year option which provides for averaging power purchase prices and the PF Rate over the term of the contract; (2) DSI benefit payments for 460 aMW were reduced 8 percent each year for FY 2007-2009, resulting in a financial benefit based on the difference between the price paid on forward-market electricity purchases that have been acquired and the lowest-cost flat PF rate up to a maximum of $11.04/MWh ($44.5 million/year); and (3) Unused benefits (100 aMW) of one aluminum DSI Customer were allocated to the other two aluminum DSI customers effective October 1, 2007. The 8 percent reduction does not apply to the 100 aMW. The financial benefit payment for this portion is established annually and is based on the difference between the price paid on market electricity purchases that have not yet been acquired and the lowest-cost annual flat PF rate up to a maximum of $12.00/MWh or $10.5 million/year for FY 2009. This results in a potential maximum payment of $55 million/year for FY 2009 to the aluminum company DSIs. Relative to the Final Proposal, these changes reduced the DSI benefit risk by locking in the benefits at a lower level for 460 aMW with the DSI benefit risk exposure limited to the 100 aMW.

1.12.1 Data and Modeling Methodology

BPA modeled the risk associated with service to the aluminum smelters in the DSI Benefit Risk Model and the risk associated with making an FPS sale of 17 aMW to Port Townsend (PT) at the flat PF rate in RiskMod, which sells the 17 aMW at a PF-equivalent flat rate rather than as a surplus energy sale at variable prices on the wholesale power market. The revenues and loads associated with this FPS sale were included under West Hub FPS Sales in the Revenue Forecast component of the WPRDS and under Interregional Transfers Out in the Load Resource Study, which are both inputs into RiskMod. *See* the Revenue Forecast component of the FY 2009 Wholesale Power Rate Development Study, WP-07-FS-BPA-13 and FY 2009 Load Resource Study, WP-07-FS-BPA-09. The reduction in surplus energy sales and revenues were computed via the load and resource values in RiskMod.

For the WP-07 Final Supplemental Proposal, BPA assumes in the DSI Benefit Risk Model that the benefits to the aluminum smelters (560 aMW) will be monetized and the aluminum smelters will maximize their benefits and adjust their energy usage (to as low as 280 aMW) to minimize their per aMW effective (after BPA payments) electricity prices. For a complete description of the DSI service benefits, refer to the DSI ROD and DSI Supplemental ROD.

Financial benefits for 460 aMW were fixed at $44.5M/Yr to reflect these benefits were locked in via changes in the implementation of the DSI contracts since the Final Proposal. Benefit risk computations for the 100 aMW were based on comparisons between forward market electricity prices and the lowest cost flat PF rates, assuming a complete shutdown of this load at forward market electricity prices of $70.00/MWh or more (no benefit payments) and no benefit payments for prices below the lowest cost flat PF rates.

Unlike in the WP-07 Initial Supplemental Proposal, simulated forward market price risk data for a 12-month strip of power for FY 2009 (simulated by the Forward Market Price Risk Model) were not used in the WP-07 Final Supplemental Proposal. *See* Section 1.15 of this Study Documentation, regarding a discussion of why the Forward Market Price Risk Model was not run for FY 2009 in the WP-07 Final Supplemental Proposal. Instead, the deterministic forecast annual forward market price of $51.94/MWh estimated by AURORA for FY 2009 (*See* FY 2009 Market Price Forecast Study and Study Documentation, WP-07-FS-BPA-11 and WP-07-FS-BPA-11A, regarding the forward market price for FY 2009) was input into the DSI Benefit Risk Model for all 3000 games.

Similarly, annual average flat PF rate risk data (due to either a CRAC or DDC being triggered for FY 2009 depending on FY 2008 financial results) for FY 2009 (calculated by the ToolKit Model) were not used in the WP-07 Final Supplemental Proposal. *See* Section 3.2 in the FY 2009 Risk Analysis Study, WP-07-FS-BPA-12), regarding the ToolKit Model. Such PF rate risk computations were considered irrelevant for calculating FY 2009 DSI benefit risk given the following: (1) Most of the financial results for FY 2008 are known; (2) the FY 2008 financial outlook, relative to the CRAC and DDC thresholds at the time of the WP-07 Final Supplemental Proposal, indicate that neither is likely to trigger; (3) given the deterministic forecast annual forward market price of $51.94/MWh, a DDC would have no impact on the DSI benefits since the benefits are already at the maximum value and can't be increased, and a DDC would not reduce them; and (4) given the deterministic forecast annual forward market price of $51.94/MWh, it would take a CRAC that would raise the annual flat PF rate by more than $14/MWh to impact the FY 2009 DSI benefits. For these reasons, the deterministic annual flat PF rate of $25.56/MWh calculated by RAM for FY 2009 (*See* FY 2009 Wholesale Power Rate Development Study, WP-07-FS-BPA-13, regarding RAM results) was input into the DSI Benefit Risk Model for all 3000 games.

These price and rate data were copied into the DSI Benefit Risk Model to compute DSI benefits relative to the benefits included in the Revenue Requirement when setting rates, which total $55M/year in FY 2009. (*See* FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10**.)** These values reflect the fixed $44.5 M/Yr for 460 aMW plus the maximum financial benefits at $12.00/MWh for the 100 aMW.

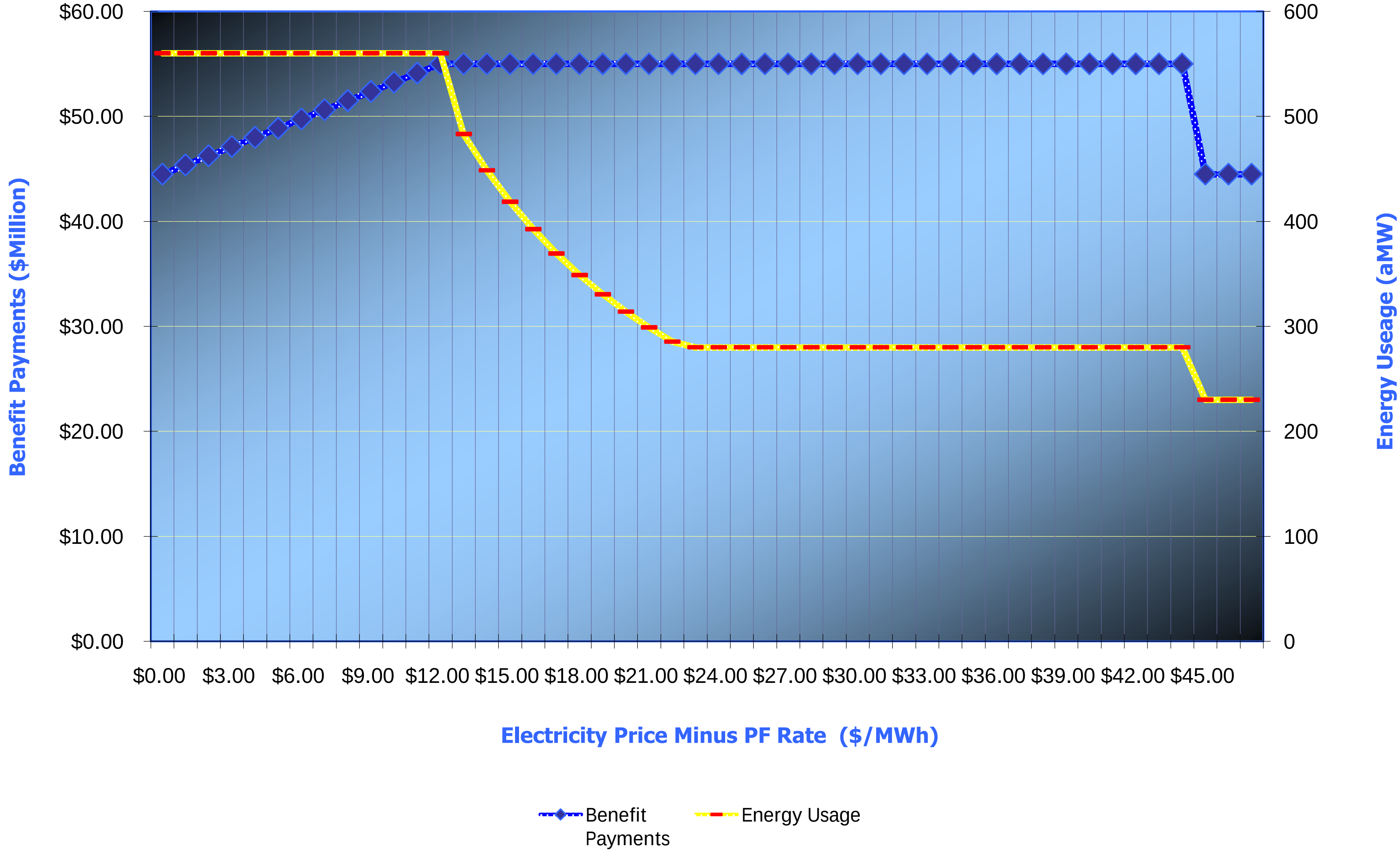
Table 26 contains an example of the algorithm used to compute the aluminum smelter benefits in the DSI Benefit Risk Model. This algorithm computes the aluminum smelter benefits, energy usage, and effective electricity prices (after BPA benefit payments) for forward market electricity prices ranging from an assumed lowest cost flat PF rates of $25.00/MWh to over $70.00/MWh. Under this algorithm, DSI benefits can range from a minimum of $44.5M to a maximum of $55M depending on the differences between forward market electricity prices and the lowest cost flat PF rates. The interrelationships between these factors are shown in Graph 10.

Table 26: Aluminum Smelter Benefit Payments and Energy Usage Algorithm Results Reflect an Assumed Effective Flat PF Rate of $25.00/MWh

(No change from the WP-07 Initial Supplemental Proposal)

Electricity Prices ($/MWh)	Electricity Prices Minus PF Rate ($/MWh)	Alum Smelter Energy Usage (aMW)	Alum Smelter Payments ($Million)	Smelter Effective Electricity Price ($/MWh)
$ 25.00	$ -	560	$ 44.5	$ 25.00
$ 26.00	$ 1.00	560	$ 45.4	$ 25.00
$ 27.00	$ 2.00	560	$ 46.2	$ 25.00
$ 28.00	$ 3.00	560	$ 47.1	$ 25.00
$ 29.00	$ 4.00	560	$ 48.0	$ 25.00
$ 30.00	$ 5.00	560	$ 48.9	$ 25.00
$ 31.00	$ 6.00	560	$ 49.7	$ 25.00
$ 32.00	$ 7.00	560	$ 50.6	$ 25.00
$ 33.00	$ 8.00	560	$ 51.5	$ 25.00
$ 34.00	$ 9.00	560	$ 52.4	$ 25.00
$ 35.00	$ 10.00	560	$ 53.2	$ 25.00
$ 36.00	$ 11.00	560	$ 54.1	$ 25.00
$ 37.00	$ 12.00	560	$ 55.0	$ 25.00
$ 38.00	$ 13.00	483	$ 55.0	$ 25.00
$ 39.00	$ 14.00	448	$ 55.0	$ 25.00
$ 40.00	$ 15.00	419	$ 55.0	$ 25.00
$ 41.00	$ 16.00	392	$ 55.0	$ 25.00
$ 42.00	$ 17.00	369	$ 55.0	$ 25.00
$ 43.00	$ 18.00	349	$ 55.0	$ 25.00
$ 44.00	$ 19.00	330	$ 55.0	$ 25.00
$ 45.00	$ 20.00	314	$ 55.0	$ 25.00
$ 46.00	$ 21.00	299	$ 55.0	$ 25.00
$ 47.00	$ 22.00	285	$ 55.0	$ 25.00
$ 48.00	$ 23.00	280	$ 55.0	$ 25.00
$ 49.00	$ 24.00	280	$ 55.0	$ 26.00
$ 50.00	$ 25.00	280	$ 55.0	$ 27.00
$ 51.00	$ 26.00	280	$ 55.0	$ 28.00
$ 52.00	$ 27.00	280	$ 55.0	$ 29.00
$ 53.00	$ 28.00	280	$ 55.0	$ 30.00
$ 54.00	$ 29.00	280	$ 55.0	$ 31.00
$ 55.00	$ 30.00	280	$ 55.0	$ 32.00
$ 56.00	$ 31.00	280	$ 55.0	$ 33.00
$ 57.00	$ 32.00	280	$ 55.0	$ 34.00
$ 58.00	$ 33.00	280	$ 55.0	$ 35.00
$ 59.00	$ 34.00	280	$ 55.0	$ 36.00
$ 60.00	$ 35.00	280	$ 55.0	$ 37.00
$ 61.00	$ 36.00	280	$ 55.0	$ 38.00
$ 62.00	$ 37.00	280	$ 55.0	$ 39.00
$ 63.00	$ 38.00	280	$ 55.0	$ 40.00
$ 64.00	$ 39.00	280	$ 55.0	$ 41.00
$ 65.00	$ 40.00	280	$ 55.0	$ 42.00
$ 66.00	$ 41.00	280	$ 55.0	$ 43.00
$ 67.00	$ 42.00	280	$ 55.0	$ 44.00
$ 68.00	$ 43.00	280	$ 55.0	$ 45.00
$ 69.00	$ 44.00	280	$ 55.0	$ 46.00
$ 70.00	$ 45.00	230	$ 44.5	N/A
$ 71.00	$ 46.00	230	$ 44.5	N/A
$ 72.00	$ 47.00	230	$ 44.5	N/A

Graph 10: Aluminum Smelter Benefit Payments And Energy Usage
(No change from the WP-07 Initial Supplemental Proposal)



1.12.2 Model and Results

Table 27 contains a copy of the top portion of the DSI Benefit Risk Model, which provides examples of how computations for 3000 outcomes per FY are performed throughout the entire Excel workbook. Based on the deterministic FY 2009 forward market price forecast of \$51.94/MWh and the deterministic average flat PF rate of \$25.56/MWh, results indicate that FY 2009 DSI benefits do not vary with all outcomes being equal to the maximum value of \$55M. Graph 11 is not applicable for the WP-07 Final Supplemental Proposal and Graph 12 shows the probability distribution for the DSI benefits for FY 2009, which indicates the value is a constant.

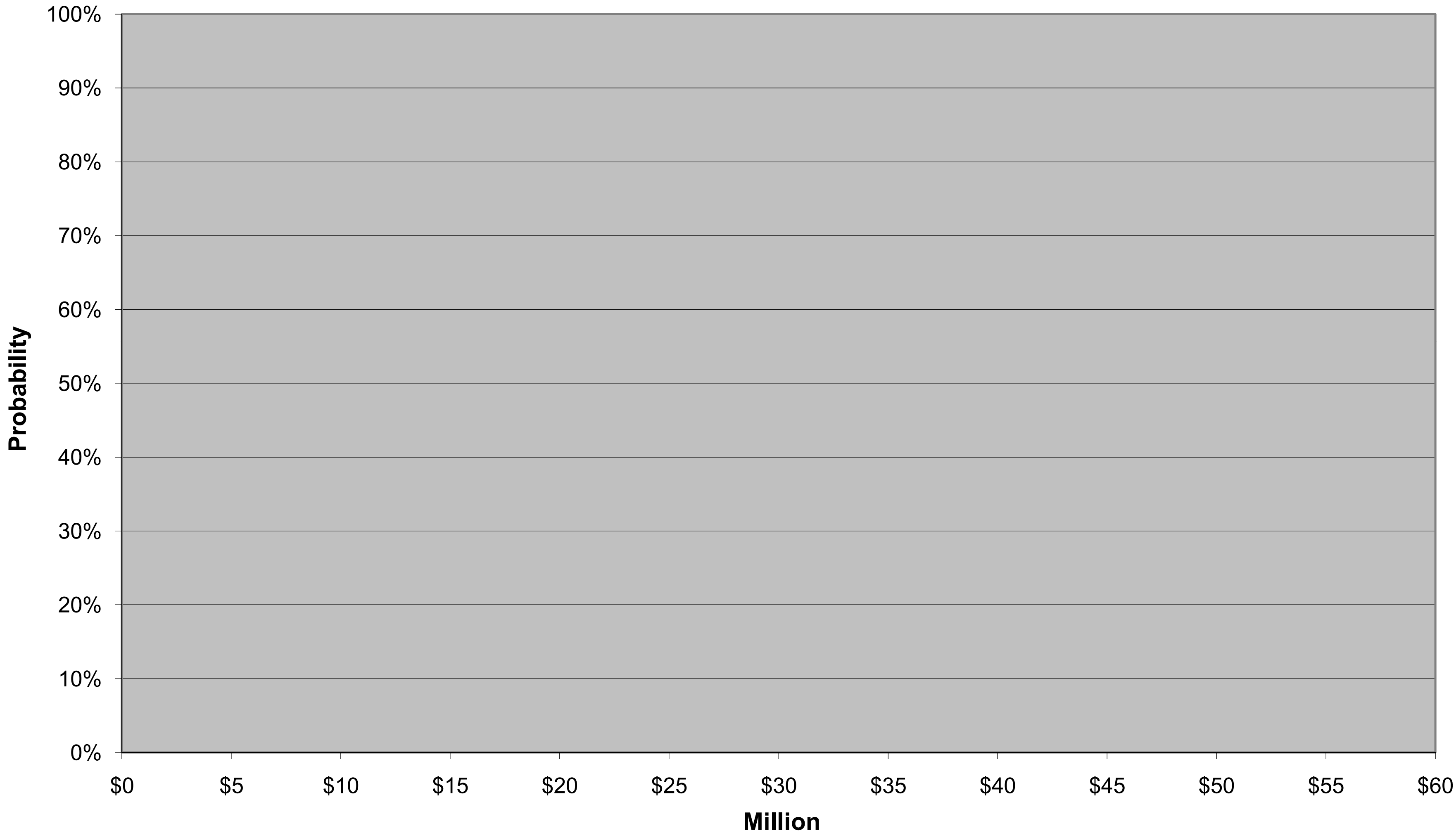
Table 27: DSI Benefit Risk Model
(Updated from the WP-07 Initial Supplemental Proposal)

Firm	Allocation	Max Electricity Price Benefit ($/MWh)	FY08-09 Payment Factor	Effective Max Benefit Price ($/MWh)
Alcoa Benefits (aMW)	320	$ 12.00	0.92	$ 11.04
CFAC Benefits (aMW)	140	$ 12.00	0.92	$ 11.04
Total Fixed Benefit (aMW)	460			
Total Fixed Payment for FY08 ($K)	$ 44,609			
Total Fixed Payment for FY09 ($K)	$ 44,487			

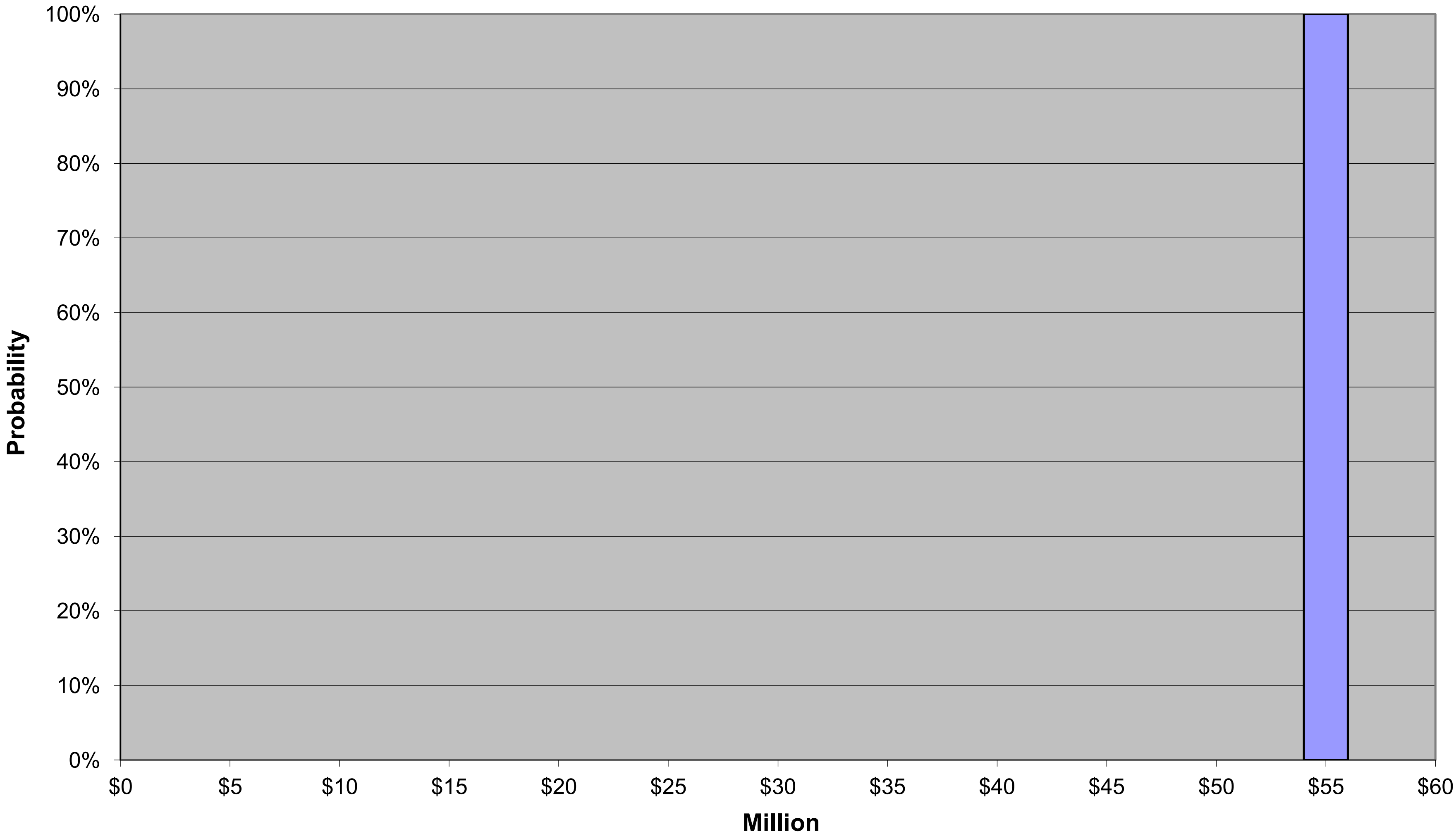
Firm	Allocation	Max Electricity Price Benefit ($/MWh)	FY08-09 Payment Factor	Effective Max Benefit Price ($/MWh)
Alcoa - GNA Reallocation (aMW)	70	$ 12.00	1.00	$ 12.00
CFAC - GNA Reallocation (aMW)	30	$ 12.00	1.00	$ 12.00
Total Variable Benefit (aMW)	100			
Total Max Variable Payment for FY08 ($I	$ 10,541			
Total Max Variable Payment for FY09 ($I	$ 10,512			
Combined Max Payment for FY08 ($K)	$ 55,149			
Combined Max Payment for FY09 ($K)	$ 54,999			
Max Electricity Price Benefit ($/MWh)	**$ 12.00**			
Shutdown Electricity Price ($/MWh)	**$ 70.00**			
Flat Vs. Shaped PF Rate Delta ($/MWh)	**$ (1.34)**			
Min Output (aMW) for Max Variable $	**50**			

3-Year Average			**$ 54,999**				**50**				**$ 51.94**				**$ 25.56**
Average (3000 iterations)	**N/A**	**N/A**	**$ 54,999**	Average	**N/A**	**N/A**	**50**	Average	**N/A**	**N/A**	**$ 51.94**	Average	**N/A**	**N/A**	**$ 25.56**
Max (3000 iterations)	**N/A**	**N/A**	**$ 54,999**	Stdev	**N/A**	**N/A**	**0**								
Min (3000 iterations)	**N/A**	**N/A**	**$ 54,999**												
					GNA Reallocation aMW Only										
	Smelter Payments ($K)				Smelter Energy Usage (aMW)				Annual Flat Forward Mkt Prices ($/MWh)				Effective Flat PF Rate ($/MWh)		
Iteration	**2007**	**2008**	**2009**		**2007**	**2008**	**2009**		**2007**	**2008**	**2009**		**2007**	**2008**	**2009**
1	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
2	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
3	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
4	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
5	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
6	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
7	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
8	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
9	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
10	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
11	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
12	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
13	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
14	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
15	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
16	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
17	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
18	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
19	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
20	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
21	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
22	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56
23	N/A	N/A	$ 54,999		N/A	N/A	50		N/A	N/A	$ 51.94		N/A	N/A	$ 25.56

Graph 11: Smelter Benefit Distribution for FY 2008
(This graph is not applicable to the WP-07 Final Supplemental Proposal)



Graph 12: Smelter Benefit Distribution for FY 2009
(Updated from WP-07 Initial Supplemental Proposal)



1.13 Wind Resource Risk Factor

The wind resource risk factor reflects the uncertainty in the amount and value of the energy generated by BPA'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 three Foote Creek projects are combined into a single project and the two Klondike projects are combined into a single project) such that the averages of the simulated monthly generation outcomes for each project closely approximate the expected monthly generation included in the FY 2009 Load Resource Study, WP-07-FS-BPA-09. These four risk simulation models are collectively referred to as Wind Generation Risk Models.

The risk of the value of the wind generation is calculated in RevSim and is based on the differences between the purchase prices specified in output contracts that wind generators have with BPA and the wholesale electricity prices at which BPA can sell the amount of variable energy produced. Under its output contracts, BPA only pays for the amount of energy that is produced.

1.13.1 Historical Data

To model monthly wind generation risk, daily average energy output data from March 2002 thru April 2005 for Stateline, January 2002 thru April 2005 for Condon, January 2002 through April 2005 for Klondike I, and October 2001 through September 2004 for Foote Creek I, II, and IV were sorted by month for each wind project, regardless of year. This process yielded a minimum of three years worth of daily output data for each month of the year from which cumulative probability distributions of daily output for each month were derived in the RiskCumul function in the @RISK computer package. The historical daily wind generation data used for this analysis were the data used to compute the monthly wind generation values included under Non-Utility Generation in the Load Resource Study. *See* FY 2009 Load Resource Study and Documentation, WP-07-FS-BPA-09 and WP-07-FS-BPA-09A, regarding this data. The historical wind generation variability (measured in terms of daily capacity factors) for Klondike I was used for the Klondike III wind project.

1.13.2 Modeling Methodology for Wind Generation Risk

Monthly wind generation variability for each of the wind projects was derived in risk simulation models in the following manner: (1) Sample the daily wind generation values from the cumulative probability distributions for each day in a given month (*i.e.*, 31 days for January); (2) Sum the daily wind generation values for all days in a given month; (3) Divide the monthly sum by the number of days in that particular month.

The daily wind generation from one day to the next day was modeled independently based on the highly variable daily generation amounts from one day to the next day exhibited in the historical data. The output of Condon, Stateline, Klondike, and Foote Creek were simulated independent of one another. However, the generation from the three Foote Creek projects was modeled together. This was done to account for the fact that all of the Foote Creek projects are all on the same ridgeline, contiguously located, and electrically connected at the same substation. The generation from the two Klondike projects was modeled together for the same reasons.

Tables 28-31 contain copies of the cumulative probability distributions of the daily output by month for each of the wind projects from which daily output risk was modeled. The values in these tables are specified in terms of daily capacity factors for which energy values can be computed by multiplying the capacity factors times the capacity value for a particular wind project. Tables 32-35 contain copies of the four risk simulation models.

Table 28: Condon Wind Project Daily Output Variability by Month
(No change from WP-07 Initial Supplemental Proposal)

Condon
Nameplate Capacity: 49.8 MW

	Cumulative Probability Distribution of Daily Capacity Factors (Energy = Capacity * Capacity Factors)											
Percentile	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Min	0.000	0.001	0.000	0.008	0.000	0.000	0.027	0.004	0.001	0.000	0.000	0.000
0.01	0.000	0.003	0.003	0.013	0.000	0.000	0.027	0.005	0.001	0.000	0.000	0.000
0.05	0.000	0.010	0.011	0.031	0.000	0.000	0.031	0.015	0.014	0.003	0.003	0.000
0.10	0.000	0.025	0.037	0.038	0.014	0.026	0.037	0.025	0.025	0.014	0.008	0.001
0.15	0.003	0.035	0.051	0.046	0.024	0.044	0.044	0.034	0.036	0.035	0.020	0.008
0.20	0.005	0.046	0.077	0.064	0.035	0.057	0.047	0.040	0.044	0.046	0.024	0.019
0.25	0.009	0.055	0.088	0.072	0.049	0.068	0.058	0.053	0.058	0.058	0.035	0.044
0.30	0.018	0.065	0.100	0.084	0.064	0.075	0.067	0.067	0.064	0.073	0.051	0.071
0.35	0.028	0.075	0.125	0.106	0.078	0.080	0.085	0.081	0.073	0.083	0.083	0.083
0.40	0.044	0.092	0.168	0.113	0.095	0.101	0.100	0.088	0.082	0.097	0.107	0.100
0.45	0.076	0.105	0.224	0.125	0.106	0.118	0.119	0.092	0.093	0.130	0.154	0.125
0.50	0.101	0.131	0.265	0.147	0.124	0.136	0.131	0.098	0.105	0.147	0.176	0.188
0.55	0.158	0.139	0.300	0.170	0.137	0.155	0.138	0.111	0.124	0.182	0.197	0.233
0.60	0.200	0.155	0.356	0.187	0.157	0.169	0.152	0.123	0.137	0.212	0.255	0.248
0.65	0.292	0.187	0.389	0.206	0.196	0.192	0.177	0.134	0.176	0.252	0.315	0.278
0.70	0.335	0.200	0.422	0.242	0.230	0.204	0.205	0.161	0.205	0.272	0.358	0.327
0.75	0.369	0.215	0.452	0.268	0.265	0.234	0.222	0.199	0.245	0.298	0.406	0.402
0.80	0.419	0.268	0.518	0.291	0.274	0.269	0.251	0.223	0.268	0.351	0.467	0.474
0.85	0.488	0.311	0.574	0.325	0.308	0.318	0.267	0.258	0.327	0.426	0.527	0.541
0.90	0.522	0.429	0.683	0.396	0.443	0.374	0.312	0.306	0.437	0.483	0.630	0.628
0.95	0.596	0.513	0.752	0.499	0.525	0.444	0.343	0.406	0.483	0.635	0.739	0.662
0.99	0.825	0.823	0.831	0.651	0.681	0.554	0.586	0.593	0.594	0.794	0.876	0.776
Max	0.866	0.953	0.901	0.712	0.696	0.628	0.723	0.719	0.758	0.859	0.931	0.800
Average	0.207	0.175	0.301	0.189	0.175	0.169	0.158	0.142	0.166	0.213	0.254	0.243
Energy (aMW)	10.3	8.7	15.0	9.4	8.7	8.4	7.9	7.1	8.3	10.6	12.6	12.1

Table 29: Combined Foote Creek I, II, and IV Wind Project Daily Output Variability by Month
(No change from WP-07 Initial Supplemental Proposal)

Foote Creek I, II, and IV
Nameplate Capacity: 33.9 MW

	Cumulative Probability Distribution of Daily Capacity Factors (Energy = Capacity * Capacity Factors)											
Percentile	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Min	0.270	0.331	0.168	0.189	0.151	0.135	0.118	0.075	0.092	0.144	0.189	0.162
0.01	0.274	0.342	0.168	0.213	0.160	0.141	0.119	0.082	0.103	0.153	0.198	0.177
0.05	0.322	0.353	0.176	0.245	0.176	0.155	0.129	0.088	0.114	0.158	0.224	0.213
0.10	0.382	0.364	0.202	0.269	0.186	0.177	0.134	0.097	0.122	0.167	0.254	0.278
0.15	0.435	0.382	0.246	0.282	0.190	0.186	0.140	0.103	0.134	0.182	0.290	0.317
0.20	0.469	0.405	0.265	0.298	0.201	0.193	0.144	0.116	0.140	0.203	0.341	0.354
0.25	0.490	0.439	0.272	0.310	0.206	0.225	0.149	0.127	0.151	0.216	0.349	0.374
0.30	0.500	0.462	0.319	0.332	0.210	0.233	0.152	0.130	0.169	0.236	0.363	0.409
0.35	0.519	0.506	0.354	0.353	0.233	0.246	0.156	0.140	0.188	0.245	0.375	0.430
0.40	0.539	0.524	0.361	0.373	0.246	0.253	0.165	0.151	0.200	0.264	0.392	0.465
0.45	0.561	0.542	0.400	0.386	0.265	0.264	0.168	0.157	0.207	0.303	0.399	0.495
0.50	0.576	0.569	0.409	0.399	0.280	0.274	0.175	0.171	0.229	0.334	0.435	0.520
0.55	0.582	0.587	0.428	0.418	0.292	0.283	0.190	0.181	0.235	0.355	0.459	0.540
0.60	0.590	0.592	0.444	0.443	0.303	0.295	0.193	0.192	0.244	0.369	0.475	0.556
0.65	0.602	0.619	0.453	0.459	0.321	0.318	0.195	0.204	0.250	0.388	0.502	0.561
0.70	0.612	0.630	0.475	0.479	0.329	0.336	0.204	0.225	0.273	0.413	0.524	0.571
0.75	0.624	0.638	0.492	0.490	0.342	0.353	0.222	0.242	0.282	0.418	0.529	0.590
0.80	0.630	0.654	0.510	0.506	0.366	0.376	0.229	0.258	0.298	0.426	0.540	0.598
0.85	0.643	0.676	0.559	0.519	0.390	0.398	0.240	0.270	0.315	0.446	0.566	0.610
0.90	0.661	0.691	0.587	0.540	0.426	0.444	0.265	0.278	0.344	0.473	0.595	0.628
0.95	0.673	0.696	0.604	0.580	0.452	0.485	0.296	0.321	0.386	0.495	0.643	0.636
0.99	0.706	0.721	0.639	0.627	0.484	0.566	0.334	0.350	0.485	0.526	0.680	0.648
Max	0.713	0.723	0.639	0.642	0.515	0.644	0.369	0.420	0.492	0.530	0.693	0.654
Average	0.545	0.543	0.398	0.405	0.287	0.293	0.189	0.184	0.230	0.321	0.435	0.478
Energy (aMW)	18.5	18.4	13.5	13.7	9.7	9.9	6.4	6.3	7.8	10.9	14.7	16.2

Table 30: Klondike I and III Wind Project Daily Output Variability by Month
(No change from WP-07 Initial Supplemental Proposal)

Klondike I and III
Nameplate Capacity: 74.0 MW

	Cumulative Probability Distribution of Daily Capacity Factors (Energy = Capacity * Capacity Factors)											
Percentile	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Min	0.000	0.000	0.003	0.001	0.007	0.010	0.002	0.008	0.002	0.000	0.000	0.000
0.01	0.000	0.001	0.004	0.002	0.022	0.027	0.017	0.018	0.009	0.000	0.000	0.000
0.05	0.000	0.002	0.015	0.012	0.050	0.049	0.052	0.045	0.017	0.002	0.000	0.000
0.10	0.000	0.007	0.027	0.037	0.080	0.068	0.106	0.068	0.032	0.007	0.003	0.000
0.15	0.001	0.015	0.049	0.063	0.131	0.092	0.155	0.096	0.050	0.021	0.005	0.001
0.20	0.003	0.025	0.065	0.094	0.158	0.137	0.205	0.131	0.070	0.037	0.007	0.004
0.25	0.007	0.033	0.109	0.134	0.182	0.191	0.256	0.173	0.084	0.058	0.022	0.007
0.30	0.011	0.045	0.135	0.164	0.231	0.248	0.302	0.216	0.105	0.080	0.036	0.010
0.35	0.015	0.050	0.167	0.186	0.294	0.310	0.338	0.249	0.154	0.107	0.044	0.019
0.40	0.021	0.068	0.201	0.214	0.326	0.346	0.363	0.283	0.191	0.137	0.050	0.036
0.45	0.033	0.094	0.246	0.244	0.379	0.401	0.416	0.301	0.217	0.216	0.058	0.047
0.50	0.048	0.104	0.316	0.274	0.424	0.427	0.478	0.357	0.272	0.232	0.064	0.071
0.55	0.073	0.135	0.360	0.297	0.456	0.470	0.553	0.378	0.302	0.277	0.083	0.102
0.60	0.113	0.189	0.416	0.353	0.491	0.489	0.577	0.411	0.368	0.323	0.144	0.114
0.65	0.132	0.229	0.482	0.391	0.546	0.595	0.622	0.448	0.436	0.348	0.196	0.177
0.70	0.185	0.258	0.533	0.426	0.567	0.616	0.639	0.510	0.497	0.400	0.233	0.196
0.75	0.255	0.287	0.565	0.488	0.609	0.732	0.678	0.584	0.527	0.449	0.268	0.260
0.80	0.287	0.361	0.595	0.531	0.704	0.768	0.727	0.642	0.605	0.530	0.387	0.289
0.85	0.304	0.487	0.687	0.598	0.735	0.811	0.785	0.699	0.651	0.569	0.508	0.330
0.90	0.404	0.593	0.757	0.664	0.824	0.853	0.824	0.750	0.705	0.645	0.549	0.381
0.95	0.562	0.713	0.822	0.808	0.903	0.894	0.854	0.799	0.769	0.714	0.633	0.500
0.99	0.673	0.808	0.887	0.904	0.970	0.961	0.900	0.843	0.821	0.895	0.802	0.685
Max	0.817	0.835	0.915	0.918	0.978	0.976	0.915	0.852	0.873	0.896	0.827	0.847
Average	0.142	0.207	0.350	0.323	0.428	0.450	0.469	0.378	0.326	0.283	0.188	0.148
Energy (aMW)	10.5	15.3	25.9	23.9	31.7	33.3	34.7	28.0	24.1	20.9	13.9	11.0

Table 31: Stateline Wind Project Daily Output Variability by Month
(No change from WP-07 Initial Supplemental Proposal)

Stateline
Nameplate Capacity: 90.4 MW

	Cumulative Probability Distribution of Daily Capacity Factors (Energy = Capacity * Capacity Factors)											
Percentile	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
Min	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000
0.01	0.000	0.000	0.000	0.000	0.003	0.001	0.002	0.001	0.000	0.000	0.000	0.000
0.05	0.000	0.000	0.003	0.007	0.005	0.003	0.005	0.003	0.000	0.000	0.000	0.000
0.10	0.000	0.000	0.018	0.017	0.013	0.006	0.020	0.010	0.000	0.000	0.000	0.000
0.15	0.000	0.000	0.036	0.028	0.019	0.009	0.025	0.015	0.008	0.001	0.001	0.000
0.20	0.000	0.001	0.063	0.049	0.041	0.021	0.044	0.033	0.014	0.007	0.002	0.000
0.25	0.000	0.002	0.086	0.078	0.068	0.029	0.070	0.049	0.022	0.020	0.005	0.001
0.30	0.001	0.005	0.125	0.105	0.091	0.037	0.094	0.080	0.039	0.027	0.011	0.003
0.35	0.002	0.009	0.240	0.132	0.114	0.071	0.130	0.114	0.061	0.063	0.027	0.014
0.40	0.005	0.012	0.299	0.170	0.140	0.101	0.167	0.152	0.074	0.095	0.034	0.024
0.45	0.009	0.017	0.343	0.194	0.168	0.143	0.201	0.180	0.090	0.126	0.047	0.031
0.50	0.015	0.025	0.387	0.212	0.195	0.179	0.221	0.196	0.125	0.143	0.067	0.053
0.55	0.045	0.043	0.425	0.244	0.208	0.213	0.259	0.223	0.179	0.215	0.113	0.133
0.60	0.089	0.087	0.508	0.285	0.232	0.260	0.310	0.251	0.200	0.241	0.176	0.158
0.65	0.176	0.108	0.546	0.305	0.307	0.337	0.329	0.280	0.277	0.290	0.241	0.254
0.70	0.222	0.141	0.585	0.357	0.409	0.412	0.391	0.314	0.316	0.329	0.346	0.316
0.75	0.269	0.191	0.623	0.399	0.482	0.505	0.415	0.342	0.372	0.392	0.446	0.356
0.80	0.325	0.234	0.647	0.503	0.507	0.563	0.453	0.384	0.482	0.457	0.528	0.471
0.85	0.376	0.306	0.699	0.537	0.578	0.628	0.491	0.480	0.526	0.483	0.585	0.505
0.90	0.671	0.393	0.750	0.658	0.645	0.691	0.554	0.551	0.614	0.545	0.760	0.587
0.95	0.787	0.569	0.847	0.719	0.728	0.769	0.604	0.686	0.721	0.622	0.822	0.692
0.99	0.878	0.951	0.875	0.821	0.858	0.880	0.815	0.760	0.804	0.788	0.857	0.779
Max	0.899	0.956	0.893	0.849	0.948	0.922	0.829	0.780	0.827	0.800	0.889	0.825
Average	0.174	0.134	0.385	0.271	0.272	0.274	0.261	0.238	0.228	0.227	0.233	0.203
Energy (aMW)	15.8	12.1	34.8	24.5	24.6	24.7	23.6	21.5	20.6	20.5	21.1	18.3

Table 32: Condon Wind Project Risk Model
(No change from WP-07 Initial Supplemental Proposal)

Condon																							
Capacity (MW)	**49.8**																						
	Month aMW	Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7	Day 8	Day 9	Day 10	Day 11	Day 12	Day 13	Day 14	Day 15	Day 16	Day 17	Day 18	Day 19	Day 20	Day 21	Day 22
Jan-05	**10.2**	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-05	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-05	**15.0**	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-05	**9.4**	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-05	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-05	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-05	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-05	**7.1**	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-05	**8.3**	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-05	**10.5**	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-05	**12.5**	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-05	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-06	**10.2**	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-06	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-06	**15.0**	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-06	**9.4**	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-06	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-06	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-06	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-06	**7.1**	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-06	**8.3**	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-06	**10.5**	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-06	**12.5**	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-06	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-07	**10.2**	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-07	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-07	**15.0**	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-07	**9.4**	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-07	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-07	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-07	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-07	**7.1**	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-07	**8.3**	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-07	**10.5**	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-07	**12.5**	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-07	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-08	**10.2**	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-08	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-08	**15.0**	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-08	**9.4**	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-08	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-08	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-08	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-08	**7.1**	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-08	**8.3**	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-08	**10.5**	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-08	**12.5**	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-08	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-09	**10.2**	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-09	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-09	**15.0**	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-09	**9.4**	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-09	**8.7**	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-09	**8.4**	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-09	**7.8**	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-09	**7.1**	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-09	**8.3**	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-09	**10.5**	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-09	**12.5**	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-09	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0

Table 32: Condon Wind Project Risk Model (Continued)
(No change from WP-07 Initial Supplemental Proposal

Condon									
Capacity (MW)									
	Day 23	Day 24	Day 25	Day 26	Day 27	Day 28	Day 29	Day 30	Day 31
Jan-05	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-05	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-05	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-05	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-05	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-05	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-05	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-05	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-05	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-05	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-05	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-05	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-06	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-06	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-06	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-06	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-06	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-06	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-06	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-06	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-06	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-06	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-06	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-06	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-07	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-07	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-07	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-07	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-07	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-07	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-07	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-07	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-07	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-07	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-07	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-07	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-08	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-08	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-08	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-08	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-08	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-08	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-08	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-08	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-08	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-08	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-08	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-08	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Jan-09	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
Feb-09	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Mar-09	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Apr-09	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4	9.4
May-09	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7
Jun-09	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Jul-09	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Aug-09	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1	7.1
Sep-09	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3	8.3
Oct-09	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
Nov-09	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Dec-09	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0

Table 33: Foote Creek I, II, and IV Wind Project Risk Model

(No change from WP-07 Initial Supplemental Proposal)

Foote Creek I, II, IV																						
Capacity (MW)	33.9																					
	Month aMW	Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7	Day 8	Day 9	Day 10	Day 11	Day 12	Day 13	Day 14	Day 15	Day 16	Day 17	Day 18	Day 19	Day 20	Day 21
Jan-05	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-05	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-05	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-05	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-05	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-05	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-05	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-05	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-05	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-05	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-05	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-05	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-06	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-06	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-06	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-06	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-06	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-06	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-06	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-06	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-06	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-06	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-06	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-06	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-07	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-07	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-07	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-07	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-07	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-07	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-07	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-07	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-07	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-07	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-07	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-07	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-08	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-08	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-08	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-08	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-08	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-08	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-08	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-08	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-08	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-08	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-08	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-08	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-09	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-09	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-09	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-09	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-09	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-09	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-09	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-09	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-09	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-09	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-09	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-09	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Table 33: Foote Creek I, II, & IV Wind Risk Model (Continued)
(No change from WP-07 Initial Supplemental Proposal)

Foote Creek I, II,										
Capacity (MW)										
	Day 22	Day 23	Day 24	Day 25	Day 26	Day 27	Day 28	Day 29	Day 30	Day 31
Jan-05	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-05	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-05	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-05	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-05	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-05	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-05	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-05	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-05	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-05	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-05	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-05	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-06	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-06	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-06	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-06	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-06	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-06	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-06	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-06	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-06	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-06	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-06	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-06	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-07	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-07	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-07	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-07	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-07	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-07	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-07	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-07	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-07	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-07	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-07	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-07	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-08	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-08	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-08	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-08	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-08	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-08	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-08	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-08	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-08	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-08	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-08	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-08	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
Jan-09	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5	18.5
Feb-09	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4	18.4
Mar-09	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5	13.5
Apr-09	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
May-09	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7	9.7
Jun-09	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9	9.9
Jul-09	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
Aug-09	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2
Sep-09	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-09	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
Nov-09	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Dec-09	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2

Table 34: Klondike I and III Wind Project Risk Model

(No change from WP-07 Initial Supplemental Proposal)

Tal

Capacity (MW)																						
Klondike I	24.0																					
Klondike III (Dec. 07)	50.0																					
	Month aMW	Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7	Day 8	Day 9	Day 10	Day 11	Day 12	Day 13	Day 14	Day 15	Day 16	Day 17	Day 18	Day 19	Day 20	Day 21
Jan-05	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-05	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-05	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-05	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-05	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-05	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-05	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-05	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-05	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-05	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-05	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-05	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Jan-06	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-06	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-06	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-06	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-06	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-06	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-06	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-06	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-06	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-06	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-06	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-06	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Jan-07	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-07	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-07	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-07	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-07	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-07	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-07	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-07	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-07	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-07	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-07	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-07	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jan-08	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Feb-08	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2
Mar-08	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9
Apr-08	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8
May-08	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8
Jun-08	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3
Jul-08	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Aug-08	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0
Sep-08	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Oct-08	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Nov-08	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
Dec-08	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jan-09	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Feb-09	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2
Mar-09	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9
Apr-09	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8
May-09	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8
Jun-09	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3
Jul-09	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Aug-09	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0
Sep-09	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Oct-09	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Nov-09	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
Dec-09	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8

le 34: Klondike I and III Wind Project Risk Model (Continued)
(No change from WP-07 Initial Supplemental Proposal)

Capacity (MW)										
Klondike I										
Klondike III (Dec. 07)										
	Day 22	Day 23	Day 24	Day 25	Day 26	Day 27	Day 28	Day 29	Day 30	Day 31
Jan-05	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-05	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-05	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-05	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-05	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-05	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-05	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-05	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-05	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-05	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-05	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-05	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Jan-06	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-06	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-06	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-06	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-06	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-06	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-06	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-06	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-06	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-06	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-06	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-06	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Jan-07	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4
Feb-07	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
Mar-07	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4	8.4
Apr-07	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7	7.7
May-07	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3	10.3
Jun-07	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jul-07	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3
Aug-07	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1
Sep-07	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8	7.8
Oct-07	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
Nov-07	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Dec-07	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jan-08	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Feb-08	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2
Mar-08	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9
Apr-08	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8
May-08	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8
Jun-08	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3
Jul-08	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Aug-08	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0
Sep-08	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Oct-08	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Nov-08	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
Dec-08	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
Jan-09	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
Feb-09	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2	15.2
Mar-09	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9
Apr-09	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8	23.8
May-09	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8	31.8
Jun-09	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3	33.3
Jul-09	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Aug-09	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0	28.0
Sep-09	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0	24.0
Oct-09	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8	20.8
Nov-09	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7	13.7
Dec-09	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8

Table 35: Stateline Wind Project Risk Model
(No change from WP-07 Initial Supplemental Proposal)

Stateline																						
Capacity (MW)	**90.4**																					
	Month aMW	Day 1	Day 2	Day 3	Day 4	Day 5	Day 6	Day 7	Day 8	Day 9	Day 10	Day 11	Day 12	Day 13	Day 14	Day 15	Day 16	Day 17	Day 18	Day 19	Day 20	Day 21
Jan-05	**15.6**	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-05	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-05	**34.7**	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-05	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-05	**24.4**	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-05	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-05	**23.6**	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-05	**21.4**	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-05	**20.5**	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-05	**20.2**	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-05	**21.0**	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-05	**18.1**	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-06	**15.6**	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-06	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-06	**34.7**	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-06	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-06	**24.4**	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-06	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-06	**23.6**	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-06	**21.4**	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-06	**20.5**	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-06	**20.2**	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-06	**21.0**	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-06	**18.1**	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-07	**15.6**	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-07	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-07	**34.7**	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-07	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-07	**24.4**	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-07	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-07	**23.6**	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-07	**21.4**	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-07	**20.5**	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-07	**20.2**	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-07	**21.0**	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-07	**18.1**	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-08	**15.6**	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-08	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-08	**34.7**	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-08	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-08	**24.4**	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-08	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-08	**23.6**	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-08	**21.4**	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-08	**20.5**	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-08	**20.2**	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-08	**21.0**	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-08	**18.1**	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-09	**15.6**	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-09	**12.0**	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-09	**34.7**	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-09	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-09	**24.4**	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-09	**24.5**	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-09	**23.6**	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-09	**21.4**	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-09	**20.5**	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-09	**20.2**	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-09	**21.0**	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-09	**18.1**	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1

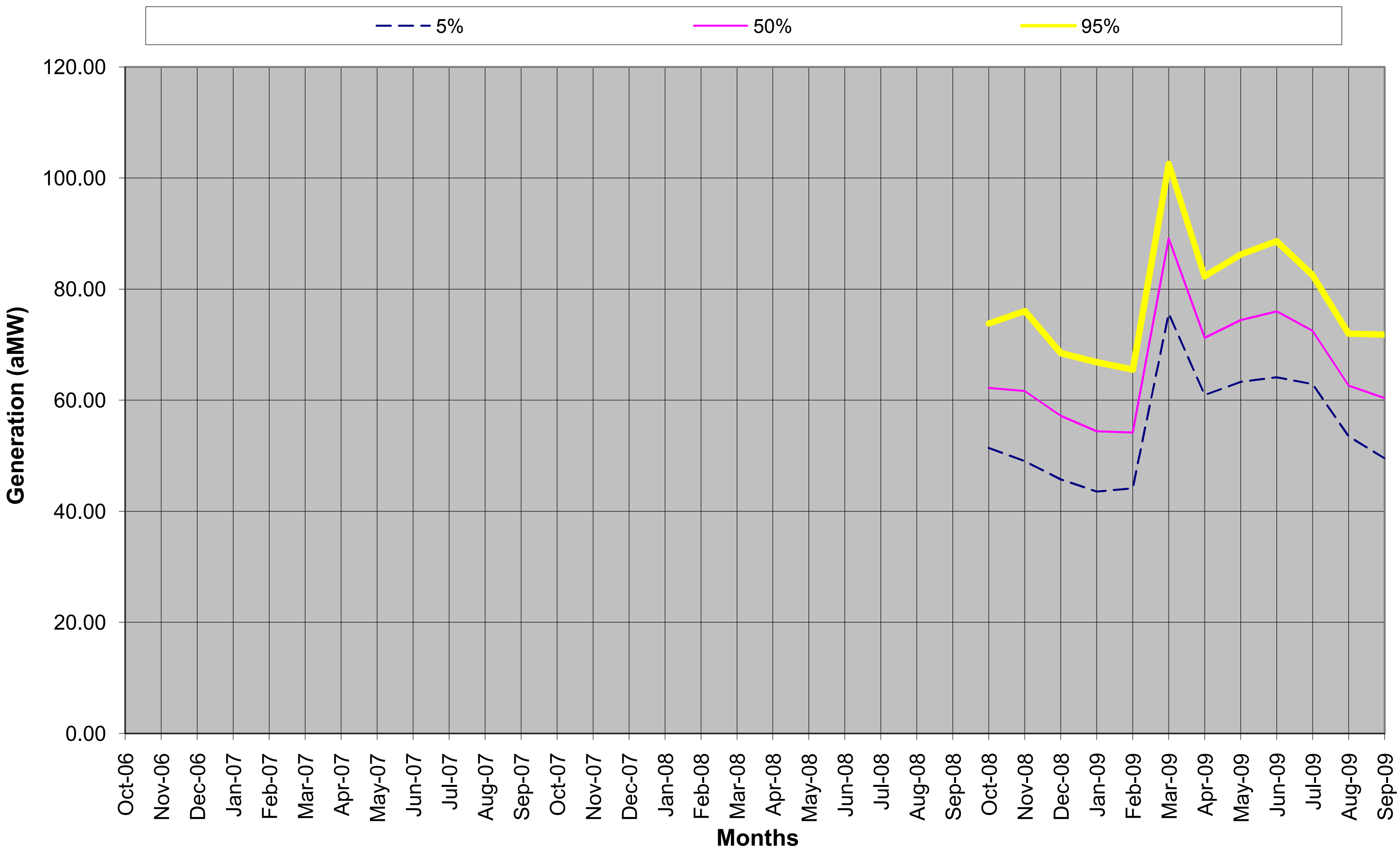
Table 35: Stateline Wind Project Risk Model (Continued)
(No change from WP-07 Initial Supplemental Propos

Stateline										
Capacity (MW)										
	Day 22	Day 23	Day 24	Day 25	Day 26	Day 27	Day 28	Day 29	Day 30	Day 31
Jan-05	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-05	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-05	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-05	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-05	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-05	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-05	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-05	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-05	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-05	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-05	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-05	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-06	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-06	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-06	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-06	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-06	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-06	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-06	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-06	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-06	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-06	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-06	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-06	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-07	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-07	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-07	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-07	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-07	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-07	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-07	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-07	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-07	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-07	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-07	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-07	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-08	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-08	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-08	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-08	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-08	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-08	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-08	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-08	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-08	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-08	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-08	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-08	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1
Jan-09	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6	15.6
Feb-09	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Mar-09	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7	34.7
Apr-09	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
May-09	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4	24.4
Jun-09	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5	24.5
Jul-09	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6
Aug-09	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4	21.4
Sep-09	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5	20.5
Oct-09	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
Nov-09	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0	21.0
Dec-09	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1	18.1

1.13.3 Wind Generation Risk Results

The monthly generation results from the risk simulations models are in terms of flat energy. Graph 13 shows the combined monthly flat energy output for all the wind projects during FY 2009 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 Supplemental Load Resource Study and Documentation. *See* FY 2009 Load Resource Study, WP-07-FS-BPA-09 and WP-07-FS-BPA-09A, regarding this data.

Graph 13: Simulated Total Wind Generation for FY 2009 (Updated from WP-07 Initial Supplemental Proposal)



1.13.4 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 weighted contract prices were used for the combined Klondike wind 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.

1.13.5 Value of Wind Generation Risk Results

Tables 36 and 37 are not applicable for the WP-07 Final Supplemental Proposal. Table 38 provides information from which the value of wind generation during FY 2009 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 are provided with the value of the wind generation being the difference between the revenues earned and purchase costs paid.

Table 36: Value of Wind Generation at Expected Wind Generation for FY 2007
(This table is not applicable to the WP-07 Final Supplemental Proposal)

Expected Generation (aMW)

Wind Project	Oct '06	Nov '06	Dec '06	Jan '07	Feb '07	Mar '07	Apr '07	May '07	Jun '07	Jul '07	Aug '07	Sep '07	Annual
Foote Creek I, II, & IV													
Stateline													
Condon													
Klondike Phase 1													
Total Wind Generation													

Contract Prices ($/MWh)

Wind Project	Oct '06	Nov '06	Dec '06	Jan '07	Feb '07	Mar '07	Apr '07	May '07	Jun '07	Jul '07	Aug '07	Sep '07	Annual
Foote Creek I, II, & IV													
Stateline													
Condon													
Klondike Phase 1													
Wtd. Average Price													

Power Purchase Costs for Expected Wind Generation ($1,000)

	Oct '06	Nov '06	Dec '06	Jan '07	Feb '07	Mar '07	Apr '07	May '07	Jun '07	Jul '07	Aug '07	Sep '07	Annual
Total Purchase Cost													

Average, Median, 5th Percentile, and 95th Percentile Spot Market Electricity Prices Estimated by AURORA ($/MWh)

	Oct '06	Nov '06	Dec '06	Jan '07	Feb '07	Mar '07	Apr '07	May '07	Jun '07	Jul '07	Aug '07	Sep '07	Annual
5%													
50%													
Average													
95%													

Revenues from Expected Wind Generation at Various AURORA Price Percentiles ($1,000)

	Oct '06	Nov '06	Dec '06	Jan '07	Feb '07	Mar '07	Apr '07	May '07	Jun '07	Jul '07	Aug '07	Sep '07	Annual
5%													
50%													
Average													
95%													

Table 37: Value of Wind Generation at Expected Wind Generation for FY 2008
(This table is not applicable to the WP-07 Final Supplemental Proposal)

Expected Generation (aMW)

Wind Project	Oct '07	Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Annual
Foote Creek I, II, & IV													
Stateline													
Condon													
Klondike Phase 1													
Total Wind Generation													**0.00**

Contract Prices ($/MWh)

Wind Project	Oct '07	Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Annual
Foote Creek I, II, & IV													
Stateline													
Condon													
Klondike Phase 1 & 3													
Wtd. Average Price													

Power Purchase Costs for Expected Wind Generation ($1,000)

	Oct '07	Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Annual
Total Purchase Cost	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Average, Median, 5th Percentile, and 95th Percentile Spot Market Electricity Prices Estimated by AURORA ($/MWh)

	Oct '07	Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Annual
5%													
50%													
Average													
95%													

Revenues from Expected Wind Generation at Various AURORA Price Percentiles ($1,000)

	Oct '07	Nov '07	Dec '07	Jan '08	Feb '08	Mar '08	Apr '08	May '08	Jun '08	Jul '08	Aug '08	Sep '08	Annual
5%	0	0	0	0	0	0	0	0	0	0	0	0	**0**
50%	0	0	0	0	0	0	0	0	0	0	0	0	**0**
Average	0	0	0	0	0	0	0	0	0	0	0	0	**0**
95%	0	0	0	0	0	0	0	0	0	0	0	0	**0**

Table 38: Value of Wind Generation at Expected Wind Generation for FY 2009
(Updated from WP-07 Initial Supplemental Proposal)

Expected Generation (aMW)

Wind Project	Oct '08	Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	Annual
Foote Creek I, II, & IV	10.9	14.7	16.2	18.5	18.6	13.5	13.7	9.7	9.9	6.4	6.3	7.8	
Stateline	20.5	21.0	18.3	15.4	12.3	34.9	24.5	24.6	24.7	23.6	21.5	20.6	
Condon	10.6	12.6	12.1	9.8	8.8	15.0	9.4	8.7	8.4	7.8	7.1	8.3	
Klondike Phase 1 & 3	19.2	13.9	10.6	9.3	15.3	25.9	24.0	30.6	30.3	33.8	27.9	24.1	
Total Wind Generation	61.2	62.3	57.2	53.1	55.0	89.3	71.7	73.7	73.4	71.5	62.8	60.8	**66.07**

Contract Prices ($/MWh)

Wind Project	Oct '08	Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	Annual
Foote Creek I, II, & IV	49.29	49.33	49.29	59.11	59.11	59.12	59.17	59.24	59.14	59.18	59.13	59.08	
Stateline	33.97	33.97	33.97	34.92	34.92	34.92	34.92	34.92	34.92	34.92	34.92	34.92	
Condon	63.32	63.32	63.32	63.32	63.32	63.32	63.32	63.32	64.90	64.90	64.90	64.90	
Klondike Phase 1 & 3	54.11	55.01	54.68	54.43	55.22	55.27	55.33	54.93	54.29	55.01	55.26	55.29	
Wtd. Average Price	48.11	48.25	48.35	52.03	53.30	49.25	50.15	49.81	49.64	49.85	49.76	50.18	**49.80**

Power Purchase Costs for Expected Wind Generation ($1,000)

	Oct '08	Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	Annual
Total Purchase Cost	2,191	2,163	2,058	2,054	1,971	3,271	2,589	2,730	2,623	2,653	2,324	2,197	**28,824**

Average, Median, 5th Percentile, and 95th Percentile Spot Market Electricity Prices Estimated by AURORA ($/MWh)

	Oct '08	Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	Annual
5%	29.65	33.31	32.49	19.38	23.99	21.95	13.34	5.51	4.30	11.00	23.77	24.95	**24.28**
50%	46.91	51.21	51.78	43.81	47.17	42.89	33.94	22.85	19.63	31.67	46.53	46.21	**40.35**
Average	47.78	51.88	52.85	48.11	53.48	45.33	35.94	26.12	22.90	34.71	51.95	49.75	**42.48**
95%	68.84	73.09	75.74	87.71	103.44	77.17	67.05	56.94	53.03	67.21	98.66	83.57	**68.83**

Revenues from Expected Wind Generation at Various AURORA Price Percentiles ($1,000)

	Oct '08	Nov '08	Dec '08	Jan '09	Feb '09	Mar '09	Apr '09	May '09	Jun '09	Jul '09	Aug '09	Sep '09	Annual
5%	1,350	1,493	1,383	765	887	1,458	688	302	227	586	1,110	1,092	**11,342**
50%	2,136	2,296	2,204	1,730	1,744	2,848	1,752	1,252	1,037	1,686	2,173	2,023	**22,882**
Average	2,176	2,327	2,249	1,899	1,978	3,010	1,855	1,432	1,210	1,847	2,426	2,178	**24,587**
95%	3,135	3,277	3,223	3,463	3,825	5,125	3,461	3,121	2,802	3,578	4,608	3,658	**43,277**

1.14 Transmission Expense Risk Factor

No changes in methodology were made to the Transmission Expense Risk model from the Final Proposal for this Supplemental Proposal, however, the model was rerun for FY 2008-2009 to consider changes to Federal surplus energy sales resulting from changes to Federal loads & resources since the Final Proposal. (*See* FY 2009 Load Resource Study, WP-07-FS-BPA-09.)

Although no changes were made to the model it was discovered that the input to the model for this Supplemental Proposal understated the amount of pre-purchased transmission. This understatement will be corrected in the Final Supplemental Proposal.

This risk factor reflects the uncertainty in PBL transmission and ancillary services expenses, relative to the expected expenses ($117 million during FY 2009) included in the Revenue Requirement when setting rates. (*See* FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10**.)** This risk is modeled in the Transmission Expense Risk Model.

1.14.1 Data and Modeling Methodology

The modeling of this risk is based on comparisons between monthly firm transmission capacity that PBL 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 the PBL has under contract, which must be paid regardless of whether or not it is used. Because the PBL has more firm transmission capacity under contract than it has firm contract sales, the probability distributions for these expenses is asymmetrical since the PBL 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.

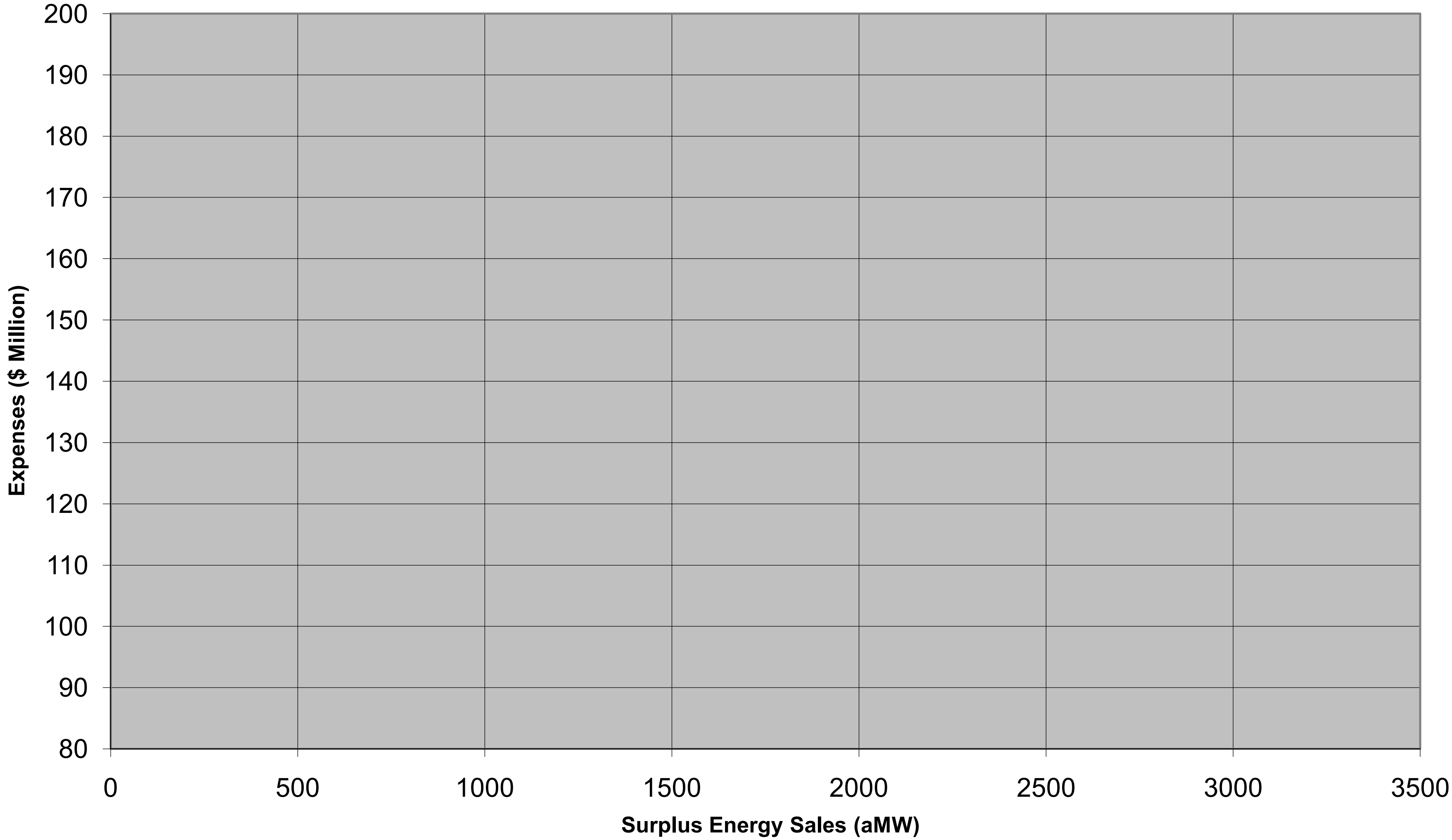
Under conditions where the PBL sells more energy than it has firm transmission rights, transmission and ancillary services expenses will increase. Alternatively, under conditions where the PBL sells less energy than it has firm transmission rights, transmission expenses will remain unchanged but ancillary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

1.14.2 Results

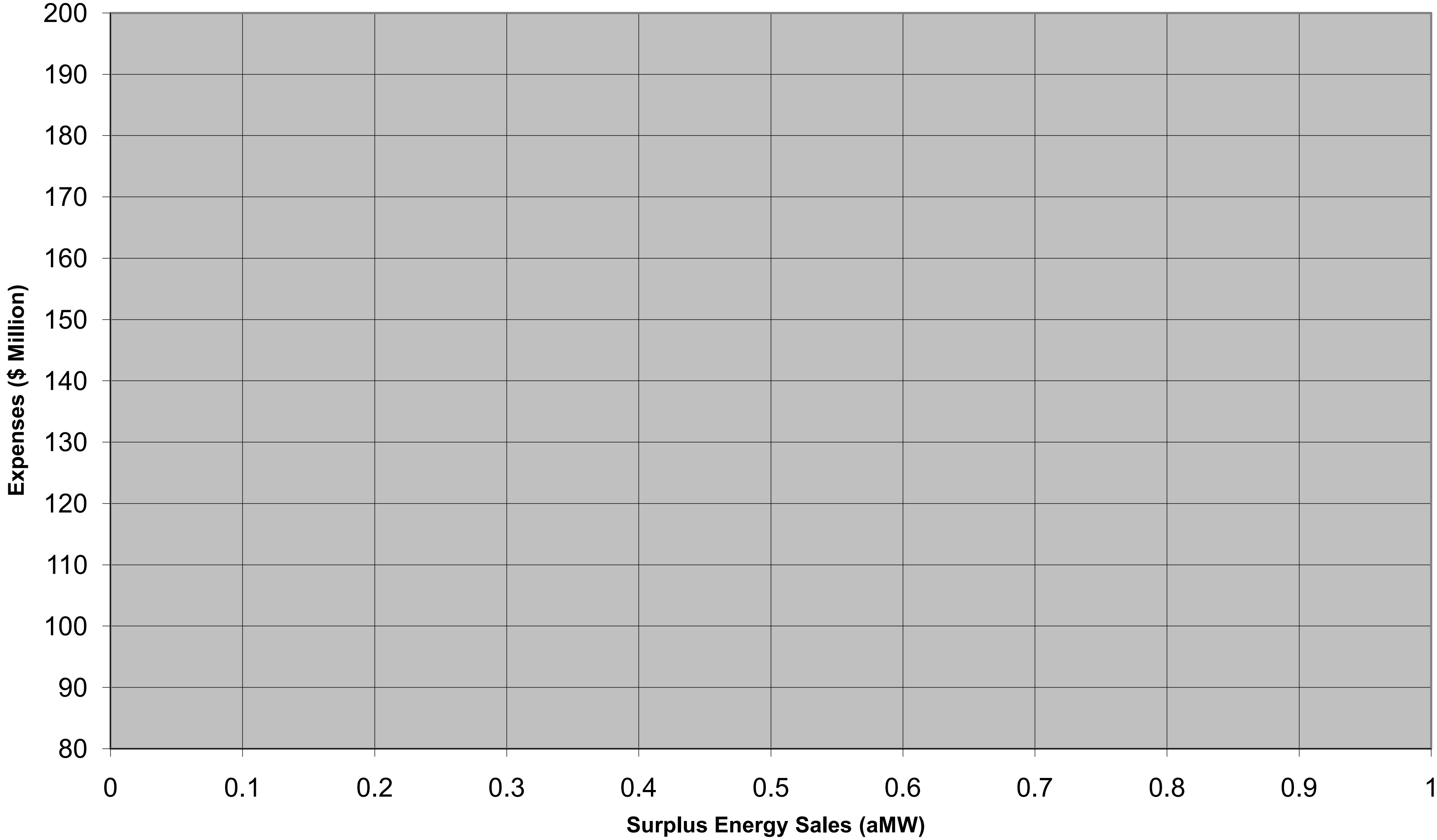
Results shown in Graph 16 indicate how transmission and ancillary service expenses vary depending on the amount of surplus energy sales. In this graph, the PBL transmission and ancillary services expenses do not fall below $95 million/year, regardless of the amount of surplus energy sales, because the PBL must pay for the take or pay firm transmission capacity it has under contract. This $95 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 Graph 19 reflect the probability distributions for transmission and ancillary service expenses during FY 2009. This graph indicates how often transmission and ancillary service expenses fall within various expense ranges.

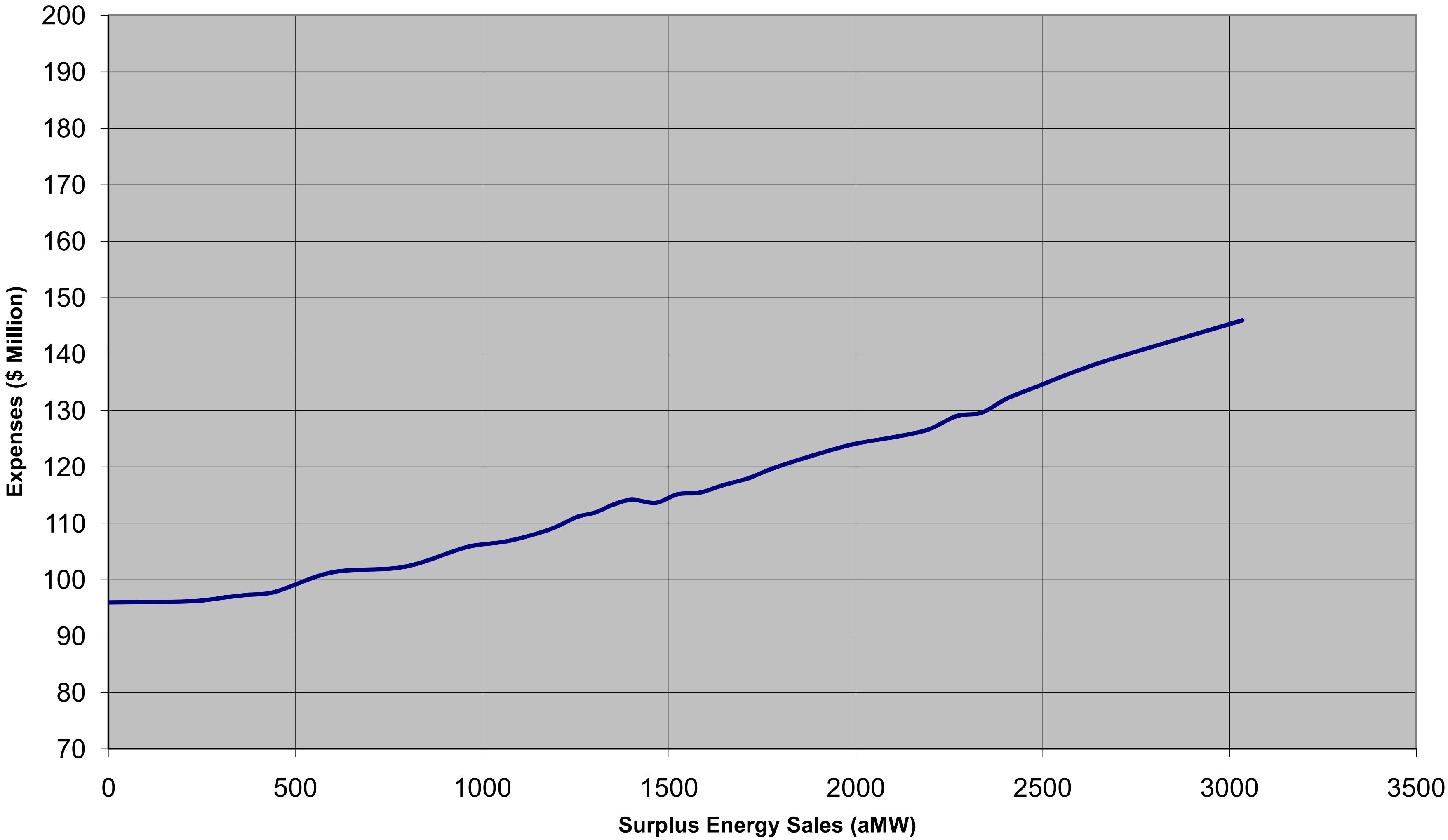
Graph 14: PBL Transmission & Ancillary Services Expenses vs. Surplus Energy Sales (FY07)
(This graph is not applicable to the WP-07 Final Supplemental Proposal)



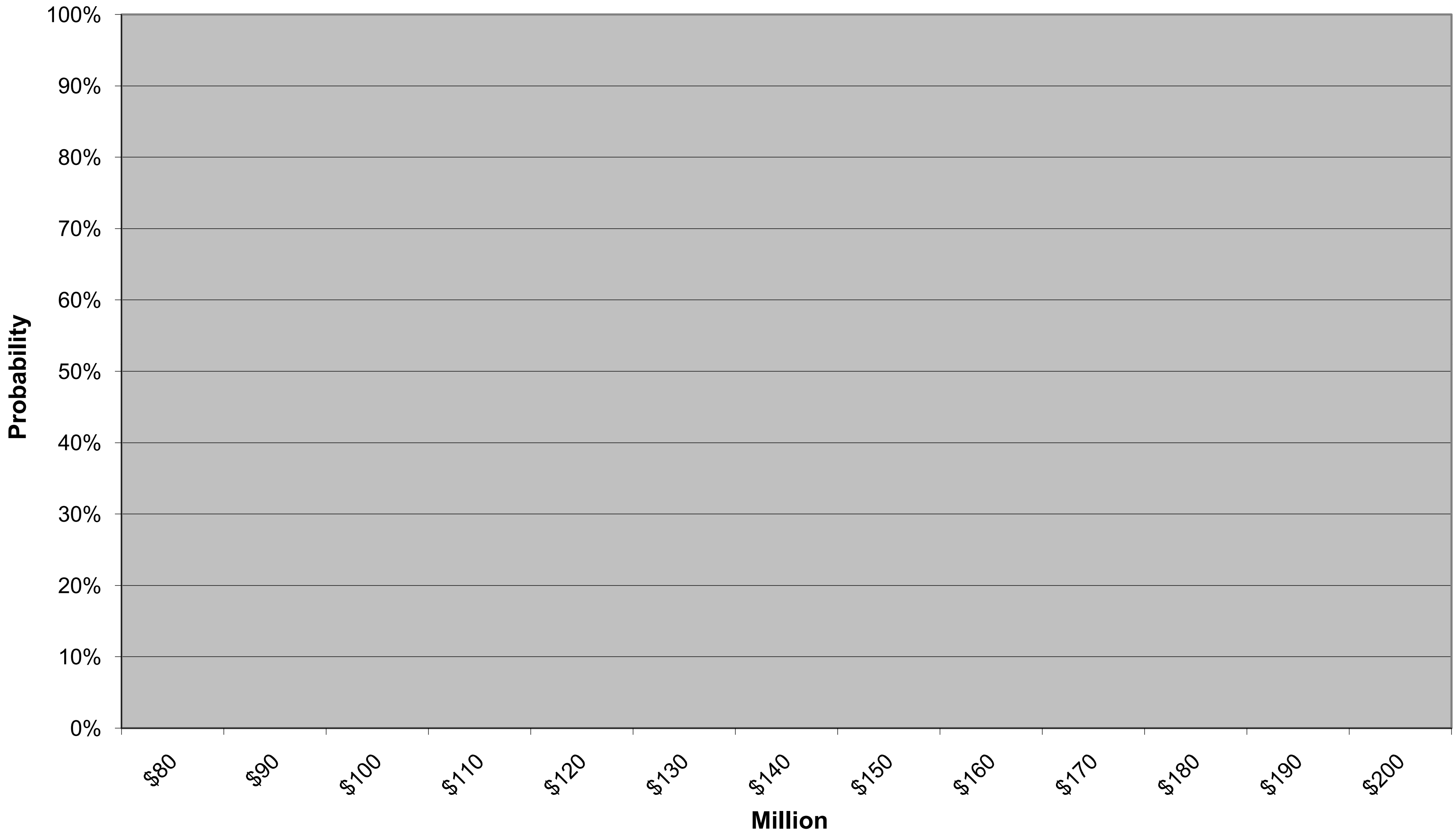
Graph 15: PBL Transmission & Ancillary Services Expenses vs. Surplus Energy Sales (FY08)
(This graph is not applicable to the WP-07 Final Supplemental Proposal)



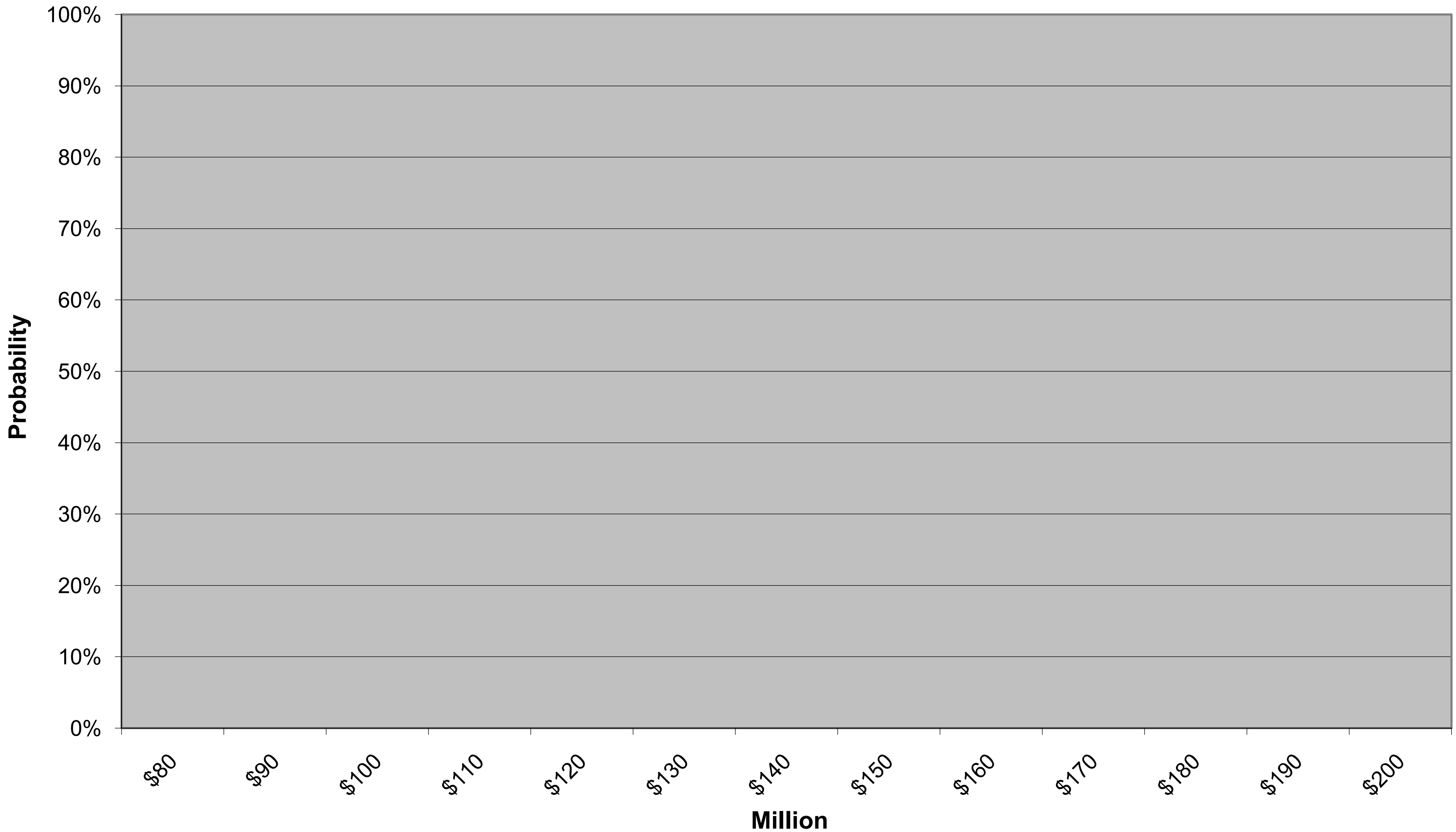
Graph 16: PBL Transmission & Ancillary Services Expenses vs. Surplus Energy Sales (FY09)
(Updated from WP-07 Initial Suppplemental Proposal)



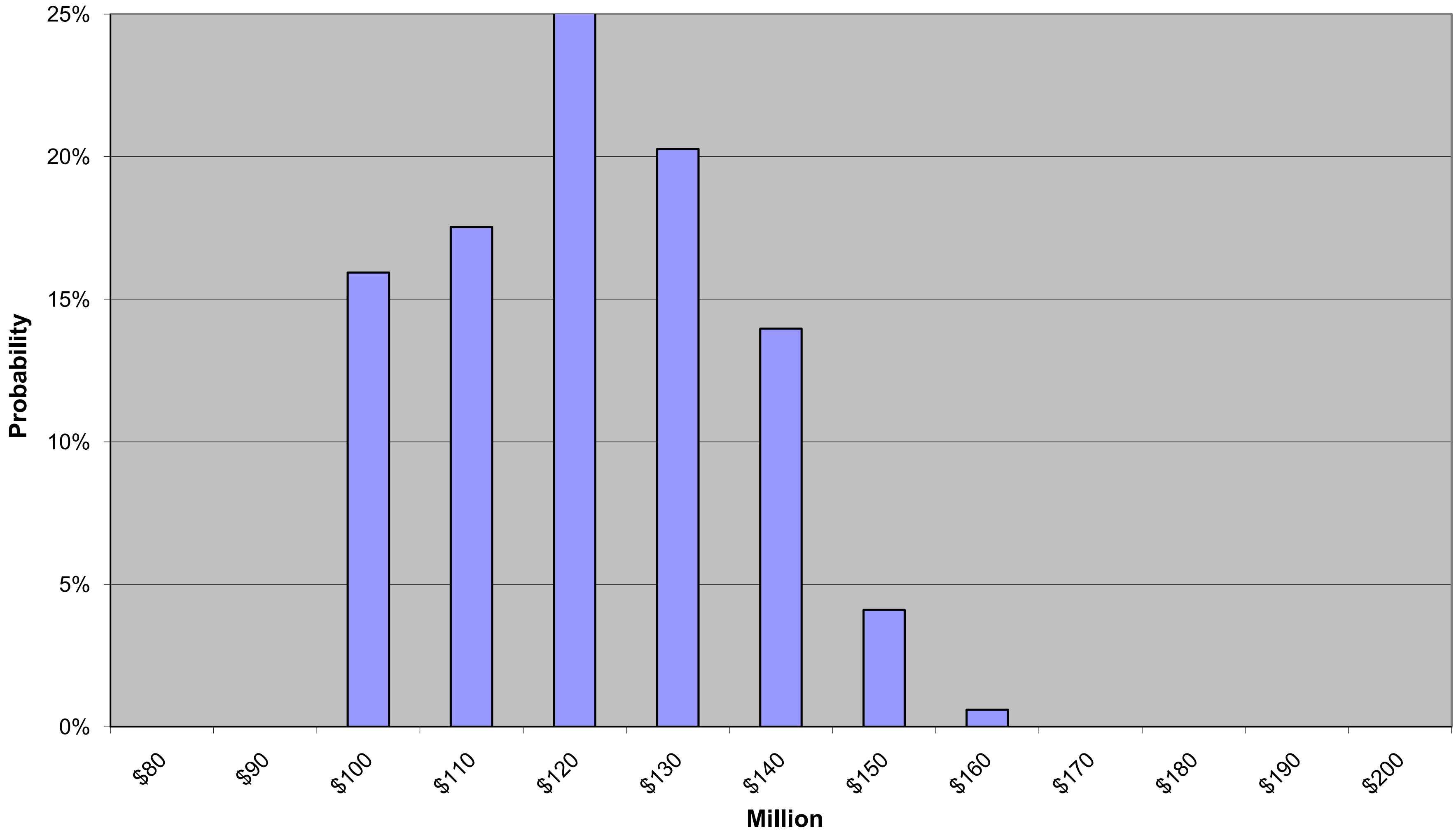
Graph 17: PBL Transmission and Ancillary Service Expense Distribution for FY 2007
(This graph is not applicable to the WP-07 Final Supplemental Proposal)



Graph 18: PBL Transmission and Ancillary Service Expense Distribution for FY 2008
(This graph is not applicable to the WP-07 Final Supplemental Proposal)



Graph 19: PBL Transmission and Ancillary Service Expense Distribution for FY 2009
(Updated from WP-07 Initial Supplemental Proposal)



1.15 Forward Market Price Risk Model

The Forward Market Price Risk Model was developed for the purpose of quantifying the risk associated with actual annual average forward market prices (*i.e.*, for a 12-month strip of power) differing from the forecasted annual average forward market prices used when setting rates. Forward market price results from this risk model are used in the DSI Benefit Risk Model to compute DSI benefit risk relative to the expense values included in the Revenue Requirement. *See* FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10 and Section 1.12 of this Study Documentation, regarding DSI benefits and risk.

Simulated forward market price risk data for a 12-month strip of power for FY 2009 (simulated by the Forward Market Price Risk Model) were not used in the WP-07 Final Supplemental Proposal, which is a change from the WP-07 Initial Supplemental Proposal. This approach is consistent with what was done in the WP-07 Final Proposal, in which the forward market price forecast for FY 2007 was treated as known and having no risk. *See* Risk Analysis Study Documentation, WP-07-FS-BPA-04A. Such an approach reflects the limited uncertainty in what the forward-market price risk for a 12-month strip of power would be for FY 2009 at the end of FY 2008 (September 30, 2008) and is consistent with the assumption used in the WP-07 Final Proposal that the smelters would purchase a 12-month strip of flat block power at the end of September for the next FY (i.e., October 2008-September 2009 for the WP-07 Final Supplemental Proposal).

Accordingly, only the deterministic forecast annual forward market price estimated by AURORA for FY 2009 (*see* Market Price Forecast Study and Documentation, WP-07-FS-BPA-11 and WP-07-FS-BPA-11A, regarding the forward market price for FY 2009) was input into the DSI Benefit Risk Model for all 3000 games.

1.15.1 Estimation of the Historical Relationships Between Forward and Spot Market Price Movements

Table 39 is not applicable to the FY-07 Final Supplemental Proposal.

Table 39: Regression Equations that Estimate Changes in Forward Prices Across Time Based on Changes in Spot Market Prices (This table is not applicable to the WP-07 Final Supplemental Proposal)

	Spot Vs Fwd 1	Spot Vs Fwd 2	Spot Vs Fwd 3	Spot Vs Fwd 4	Spot Vs Fwd 5	Spot Vs Fwd 6	Spot Vs Fwd 7	Spot Vs Fwd 8	Spot Vs Fwd 9	Spot Vs Fwd 10	Spot Vs Fwd 11	Spot Vs Fwd 12	Spot Vs Fwd 13	Spot Vs Fwd 14	Spot Vs Fwd 15	Spot Vs Fwd 16	Spot Vs Fwd 17
R^2																	
Intercept																	
Slope																	
Std Err																	

Historical Average Monthly HLH Spot and Forward Market Price Deltas for Mid-C from January 2004 - August 2005; Derived from Daily Data

Obs	Spot	Fwd 1	Fwd 2	Fwd 3	Fwd 4	Fwd 5	Fwd 6	Fwd 7	Fwd 8	Fwd 9	Fwd 10	Fwd 11	Fwd 12	Fwd 13	Fwd 14	Fwd 15	Fwd 16	Fwd 17
1																		
2																		
3																		
4																		
5																		
6																		
7																		
8																		
9																		
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12																		
13																		
14																		
15																		
16																		
17																		
18																		
19																		
20																		

Table 39: Regression Equations that Estimate Changes in Forward Prices Across Time Based on Changes in Spot Market Prices (Continued) (This table is not applicable to the WP-07 Final Supplemental Proposal)

	Spot Vs Fwd 18	Spot Vs Fwd 19	Spot Vs Fwd 20	Spot Vs Fwd 21	Spot Vs Fwd 22	Spot Vs Fwd 23	Spot Vs Fwd 24	Spot Vs Fwd 25	Spot Vs Fwd 26	Spot Vs Fwd 27	Spot Vs Fwd 28	Spot Vs Fwd 29	Spot Vs Fwd 30	Spot Vs Fwd 31	Spot Vs Fwd 32	Spot Vs Fwd 33	Spot Vs Fwd 34	Spot Vs Fwd 35
R^2																		
Intercept																		
Slope																		
Std Err																		

Historical Average Monthly HLH Spot and Forward Market Price Deltas for Mid-C from January 2004 - August 2005; Derived from Daily Data

Obs	Spot	Fwd 18	Fwd 19	Fwd 20	Fwd 21	Fwd 22	Fwd 23	Fwd 24	Fwd 25	Fwd 26	Fwd 27	Fwd 28	Fwd 29	Fwd 30	Fwd 31	Fwd 32	Fwd 33	Fwd 34	Fwd 35
1																			
2																			
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4																			
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16																			
17																			
18																			
19																			
20																			

1.15.2 Future Price Data Sources

1.15.3 Modeling Methodology

Table 40 is not applicable to the FY-07 Final Supplemental Proposal.

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Table 40: Changes in Monthly Forward Price Curves Through Time Due to Actual Spot Market Prices Differing From Forward Market Prices at the Beginning of the Spot Months
The Amount of $/MWh that Actual Spot Market Prices Differed From Forward Market Prices at the Beginning of the Spot Months Are Indicated In Single Bordered Cells/Boxes
Results for Simulation Iteration Number 3000

(This table is not applicable to the WP-07 Final Supplemental Proposal)

Date	
Forward Month	

1.15.4 Model and Results

Table 41 and Graphs 20 and 21 are not applicable to the FY-07 Final Supplemental Proposal.

Table 41: Forward Market Price Risk Model
(This table is not applicable to the WP-07 Final Supplemental Proposal)

INPUT DATA:

	Forward Mkt	Aurora Spot	Differences
FY07 Annual Price			
FY08 Annual Price			
FY09 Annual Price			
Min Monthly Price			
Avg FY08-09 Price			

AVERAGE FY08-09 RESULTS AND COMPARISONS

	Simulated Forward Price	AURORA Spot Price	Forward Vs Spot Prices
Average (FY08-09)			
Std Dev (FY08-09)			
Correlation (FY08-09)			

	Spot Vs Fwd 1	Spot Vs Fwd 2	Spot Vs Fwd 3	Spot Vs Fwd 4	Spot Vs Fwd 5	Spot Vs Fwd 6	Spot Vs Fwd 7	Spot Vs Fwd 8	Spot Vs Fwd 9	Spot Vs Fwd 10	Spot Vs Fwd 11	Spot Vs Fwd 12
R^2												
Intercept												
Slope												
Std Err												

FY07 FY08

Forecasted FY07 Forward Price Curve

Fiscal Year		
Month		
Monthly Hours		
Forward Price Curve - Avg Aurora Spot		
Forward Price Curve - Used		
Aurora Spot Price	3000	
No. of Stdevs	3000	
Selected Annual Avg FY Forward Prices		

Simulated FY07 Forward Price Curve

Table 41: Forward Market Price Risk Model (Continued)
(This table is not applicable to the WP-07 Final Supplemental Proposal)

	Spot Vs Fwd 13	Spot Vs Fwd 14	Spot Vs Fwd 15	Spot Vs Fwd 16	Spot Vs Fwd 17	Spot Vs Fwd 18	Spot Vs Fwd 19	Spot Vs Fwd 20	Spot Vs Fwd 21	Spot Vs Fwd 22	Spot Vs Fwd 23	Spot Vs Fwd 24
R^2												
Intercept												
Slope												
Std Err												
												FY09

Forecasted FY08 Forward Price Curve

Fiscal Year													
Month													
Monthly Hours													
Forward Price Curve - Avg Aurora Spot													
Forward Price Curve - Used													
Aurora Spot Price	3000												
No. of Stdevs	3000												
Selected Annual Avg FY Forward Prices													

Simulated FY08 Forward Price Curve

Table 41: Forward Market Price Risk Model (Continued)
(This table is not applicable to the WP-07 Final Supplemental Proposal)

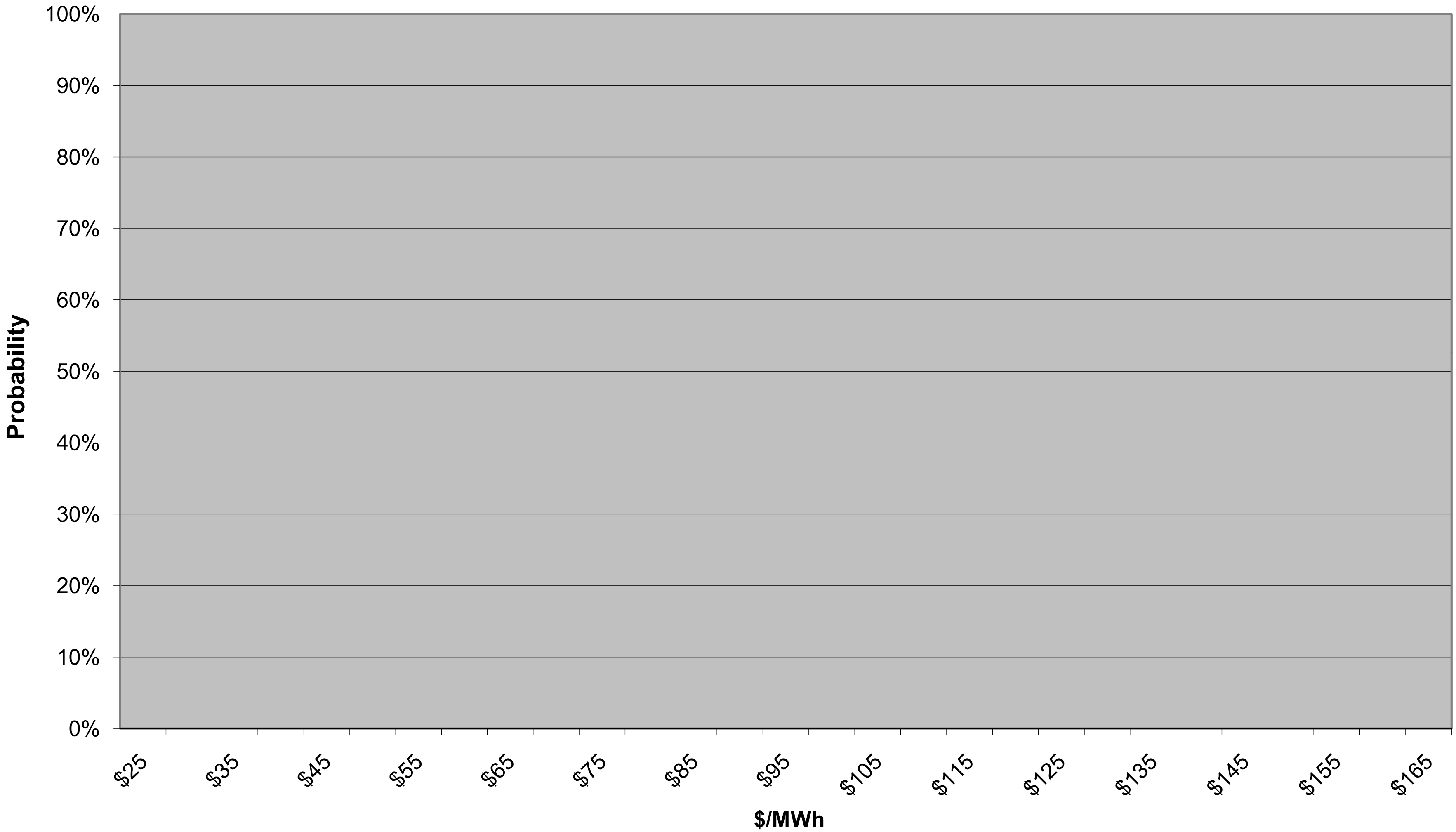
	Spot Vs Fwd 25	Spot Vs Fwd 26	Spot Vs Fwd 27	Spot Vs Fwd 28	Spot Vs Fwd 29	Spot Vs Fwd 30	Spot Vs Fwd 31	Spot Vs Fwd 32	Spot Vs Fwd 33	Spot Vs Fwd 34	Spot Vs Fwd 35
R^2											
Intercept											
Slope											
Std Err											

Forecasted FY09 Forward Price Curve

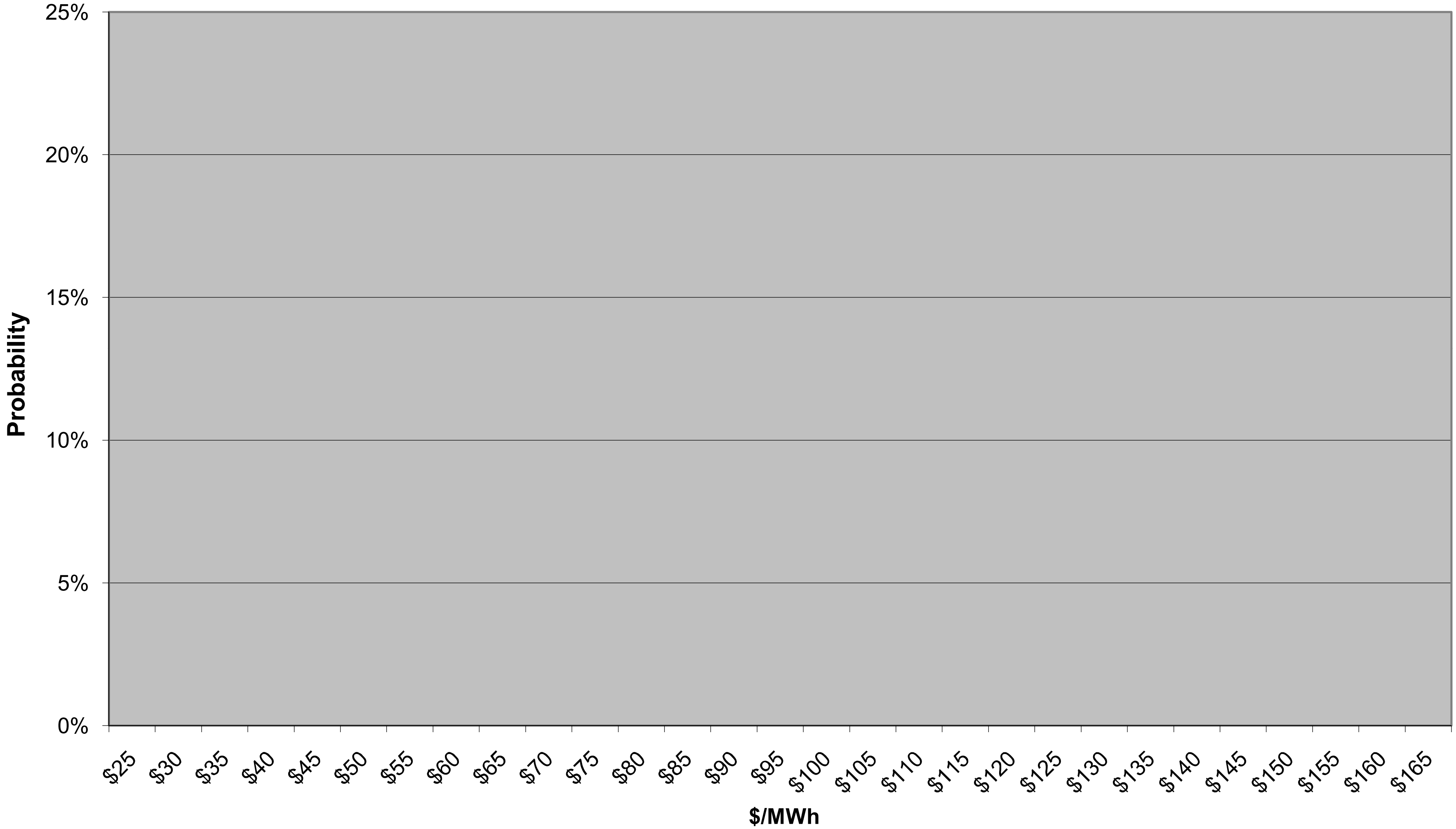
Fiscal Year												
Month												
Monthly Hours												
Forward Price Curve - Avg Aurora Spot												
Forward Price Curve - Used												
Aurora Spot Price	3000											
No. of Stdevs	3000											
Selected Annual Avg FY Forward Prices												

Simulated FY09 Forward Price Curve

Graph 20: FY 2008 Forward Market Price Distribution For 12-Month Strip of Power
(This graph is not applicable to the WP-07 Final Supplemental Proposal)



Graph 21: FY 2009 Forward Market Price Distribution For 12-Month Strip of Power
(This graph is not applicable to the WP-07 Final Supplemental Proposal)



1.16 Revenue Simulation Model (RevSim)

The purpose of the RevSim module within RiskMod is to determine, via simulation, PBL's operational net revenue risk. Inputs to RevSim include risk data simulated by RiskSim and the AURORA model along with deterministic monthly load and resource data, monthly PF rates, and non-varying revenues and expenses from the FY 2009 Load Resource Study, WP-07-FS-BPA-09, the Revenue Forecast component of the FY 2009 Wholesale Power Rate Development Study, WP-07-FS-BPA-13, and the RAM2007.

RevSim uses these inputs to calculate all revenues and expenses needed to determine PBL operational net revenues. These revenues and expenses include revenues from firm power sales (including the SLICE product), surplus energy sales revenue, 4(h)(10)(C) credits, power purchase expenses, and purchase expenses for wind generation. Additional net revenue adjustments include varying DSI benefits and transmission expenses, which are computed external to RevSim and are then input into the model. These variable revenues and expenses are then combined with deterministic revenues and expenses to calculate PBL operational net revenues.

RevSim calculates firm and surplus energy revenues and balancing power purchase expenses under various load, resource, and market price conditions to estimate PBL's operational net revenue risk. A key attribute of RevSim is that it is a HLH and LLH load and resource model. For each simulation, RevSim calculates PBL's HLH and LLH load and resource condition and determines HLH and LLH surplus energy sales and power purchases.

Transmission losses on BPA's transmission system are incorporated into RevSim by reducing Federal hydro generation and CGS output by 2.82 percent. This factor excludes losses on the Southern Intertie. This loss factor is identical to the loss factor used in the FY 2009 Load Resource Study, WP-07-FS-BPA-09.

Electricity prices estimated by AURORA are applied to the surplus sales and power purchase amounts to determine surplus energy revenues and power purchase expenses. These HLH and LLH revenues and expenses are then combined with deterministic revenues and expenses to calculate PBL operational net revenues.

RevSim calculates the 4(h)(10)(C) credit that BPA can collect for each of the 50 water years for FY 2009. The 4(h)(10)(C) credit is a provision in the 1980 Pacific Northwest Power Planning and Conservation Act that allows BPA and its ratepayers to receive a credit for non-power fish and wildlife impacts attributable to Federal projects. The 4(h)(10)(C) credits that BPA can collect for each of the 50 water years for FY 2009 is determined by summing the costs of the operational impacts, the expenses, and the capital costs associated with fish and wildlife mitigation measures, and then multiplying the total cost by 0.223 (22.3 percent).

Power purchases (aMWs) that qualify for 4(h)(10)(C) credits vary depending on monthly hydro operations due to fish mitigation measures. The amounts of power purchases (aMWs) that qualifies for 4(h)(10)(C) credits is derived external to RevSim, but are used in RevSim to calculate the dollar amount of the 4(h)(10)(C) credits. A description of the methodology used to derive the amounts of the power purchases (aMWs) associated with the 4(h)(10)(C) credits is contained in the FY 2009 Load Resource Study, WP-07-FS-BPA-09, and in the FY 2009 Load Resource Study Documentation, WP-07-FS-BPA-09A, contains the 4(h)(10)(C) power purchase amounts for FY 2009.

The costs of the operational impacts for Fish & Wildlife measures are calculated for each of the 50 water years in RevSim for FY 2009 by multiplying the amount of monthly power purchases (aMWs) that qualifies for 4(h)(10)(C) credits in a given water year by the flat monthly spot market electricity prices (computed from the AURORA HLH and LLH spot market electricity prices) for the same water year. The expenses and capital costs associated with the 4(h)(10)(C) credit are determined external to RevSim and are input into RevSim, *See* FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10, regarding expenses and capital costs.

The calculation of rates requires two different analyses by RevSim, which are referred to as the "50 Water Year Run" and the "Risk Simulation Run." The 50 Water Year Run provides data to the RAM2007 model for calculating base rates. The Risk Simulation Run provides data to the ToolKit model for the purpose of determining if BPA has met its financial objectives for the rate period.

1.16.1 Fifty (50) Water Year Run

The purpose of the 50 Water Year Run is to calculate revenues from surplus energy sales, expenses associated with purchases needed to meet firm load, and 4(h)(10)(C) credits. The risk data simulated by RiskSim are not used in the 50 Water Year Run of RevSim. CGS output and PBL loads are provided to RevSim by repeating the respective forecasted values for each of the 50 simulations. HLH and LLH spot market electricity prices from the 50 Water Year Run of AURORA are used to calculate surplus energy revenues and power purchase expenses associated with the monthly HLH and LLH surplus and deficit amounts for each of the 50 water years. Surplus energy sales amounts, surplus energy sales revenues, power purchase amounts, and power purchases expenses are reported in the Revenue Forecast component of the FY 2009 Wholesale Power Rate Development Study WP-07-FS-BPA-13A.

The 50 Water Year Run of RiskMod calculates the annual 4(h)(10)(C) credits for inclusion into the Revenue Forecast and RAM2007 calculation of rates. The dollar amounts of 4(h)(10)(C) credits for the 50 Water Year Run of RiskMod are reported in the Revenue Forecast component of the FY 2009 Wholesale Power Rate Development Study Documentation, WP-07-FS-BPA-13A.

1.16.2 Risk Simulation Run

The Risk Simulation Run of RevSim provides PBL annual net revenues for 3000 iterations per FY considering several risk variables in addition to the variable hydro generation and 4(h)(10)(C) credits used in the 50 Water Year Run. All the risk data, with the exception of PF load variability, are input into RevSim as values. PF load variability is quantified as ratios relative to 1.00. These load variability ratios are multiplied by the forecasted monthly PF loads subject to the load variance charge (*see* FY 2009 Load Resource Study, WP-07-FS-BPA-09). The differences between the simulated and forecasted values are added to the forecasted monthly

PF loads reported in the FY 2009 Load Resource Study, WP-07-FS-BPA-09, to obtain variable PF loads**.**

These variable PF loads are multiplied by the PF rate to obtain variable PF energy revenues. In addition to adjusting PF loads (energy), the ratios (relative to 1.00) are multiplied by the forecasted monthly PF demand in the Revenue Forecast component of the FY 2009 Wholesale Power Rate Development Study, WP-07-FS-BPA-13, to obtain variable PF demand. These variable demand values are multiplied by the PF demand charge to obtain variable PF demand revenues.

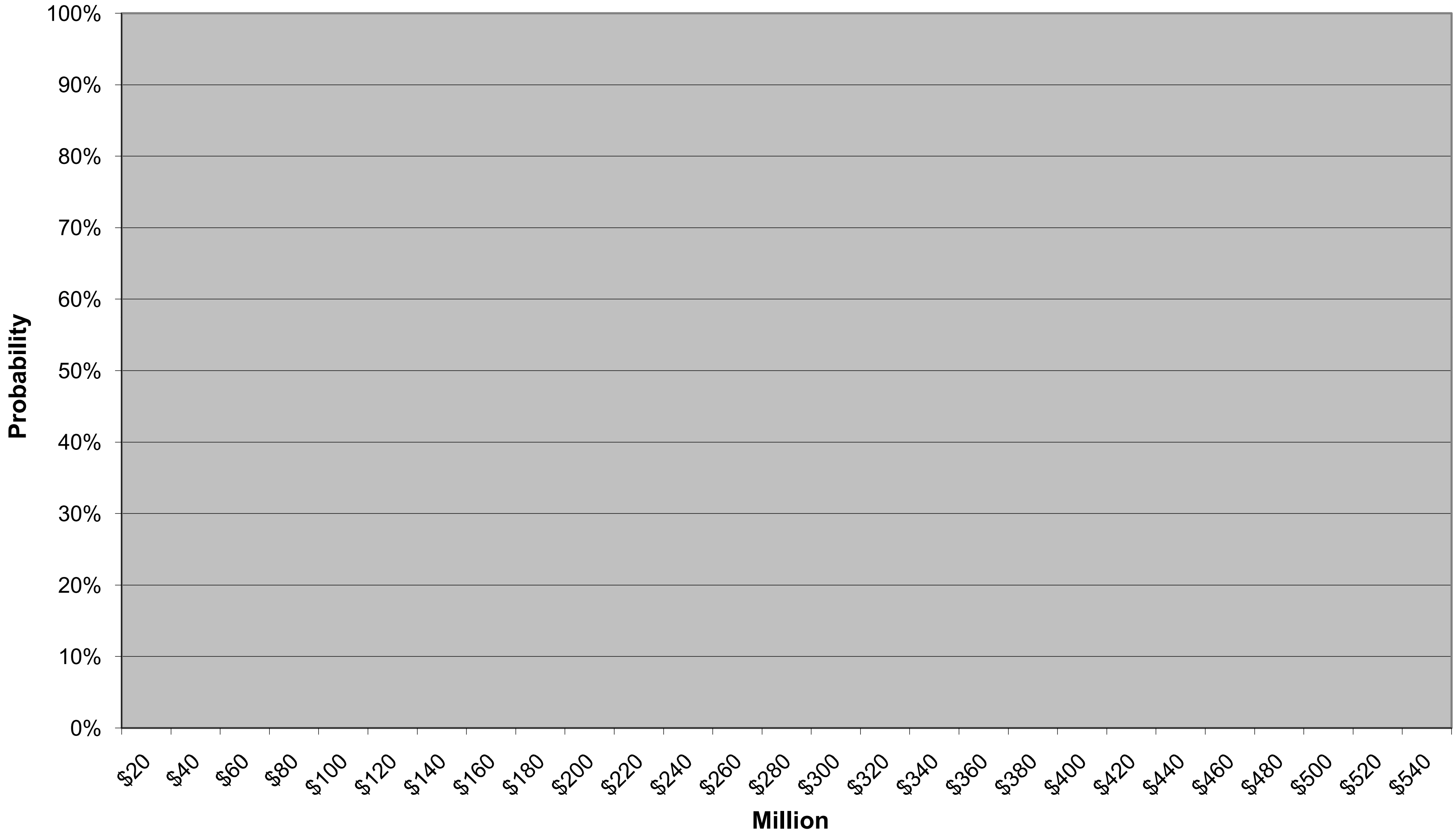
Surplus energy sales revenue and power purchase expenses are based on Federal hydro generation (50 water years), Federal HLH hydro generation ratios (50 water years), BPA load variability, CGS output variability, variable wind generation, transmission expenses, and AURORA prices. RevSim calculates monthly HLH and LLH surplus energy sales and power purchases and applies corresponding HLH and LLH prices estimated by the AURORA Model to determine surplus energy sales revenues and power purchase expenses.

For a given simulation, Federal hydro generation data and HLH hydro generation ratios are determined by the water year sampled for the "hydro index." Given the hydro index (water year) for a simulation, Federal hydro generation data are retrieved from the Risk Input Database.

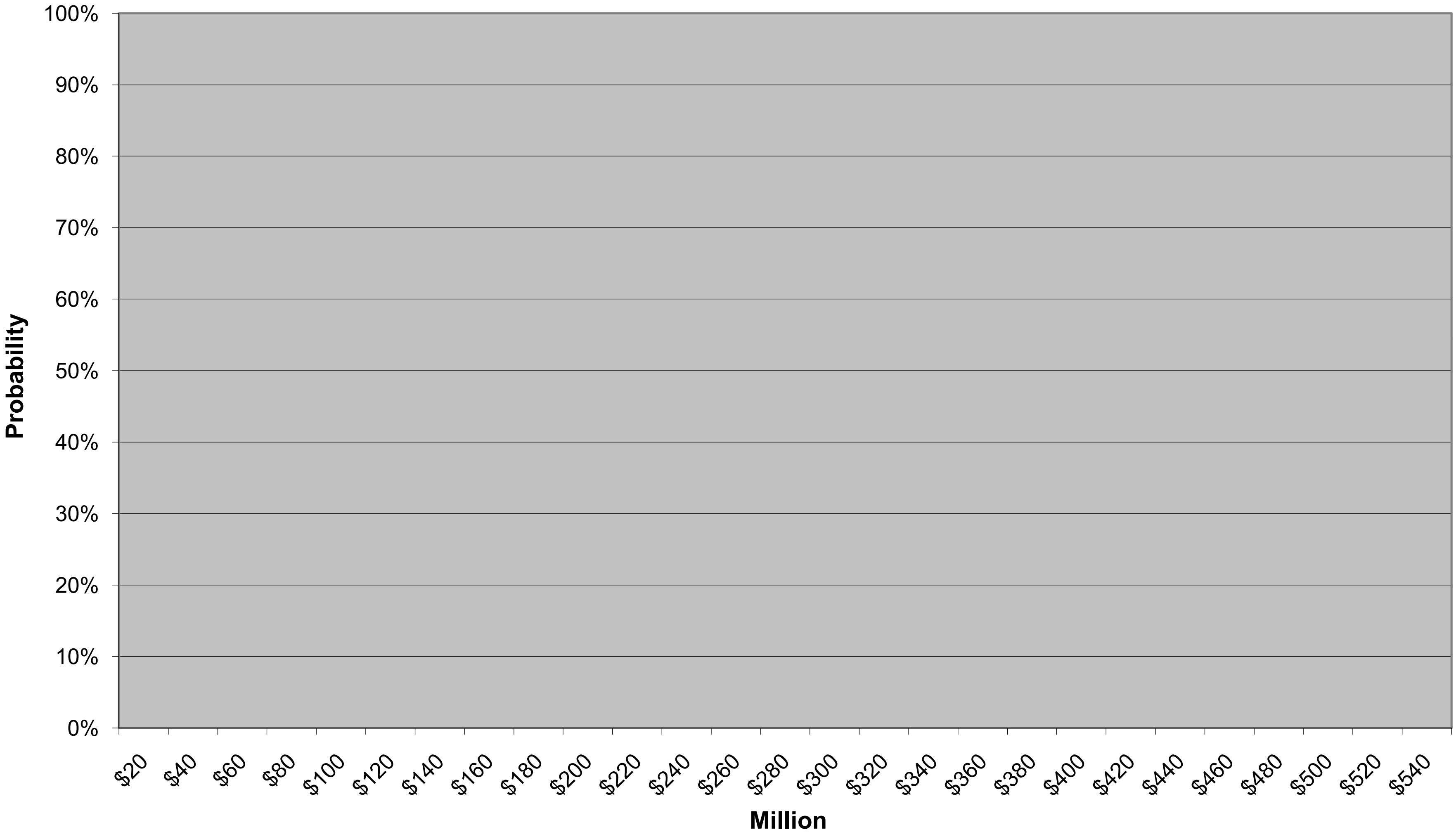
The operational portion of the 4(h)(10)(C) credit is computed from 4(h)(10)(C) power purchase amounts and AURORA prices that are read from the Risk Input Database. The variable operational portion of the credit is combined with the deterministic expense and capital portions to calculate the total 4(h)(10)(C) credit. The 4(h)(10)(C) credits for the one-year rate period calculated in the Risk Simulation Run are included in the PBL net revenues passed to the ToolKit Model. Graph 24 shows the probability distributions of the 4(h)(10)(C) credits calculated in the Risk Simulation Run for FY 2009.

The difference in the 4(h)(10)(C) credits between the 50 Water Year Run and the Risk Simulation Run is derived from in the differences in the spot market electricity prices AURORA estimated between the 50 Water Year Run and the Risk Simulation Run.

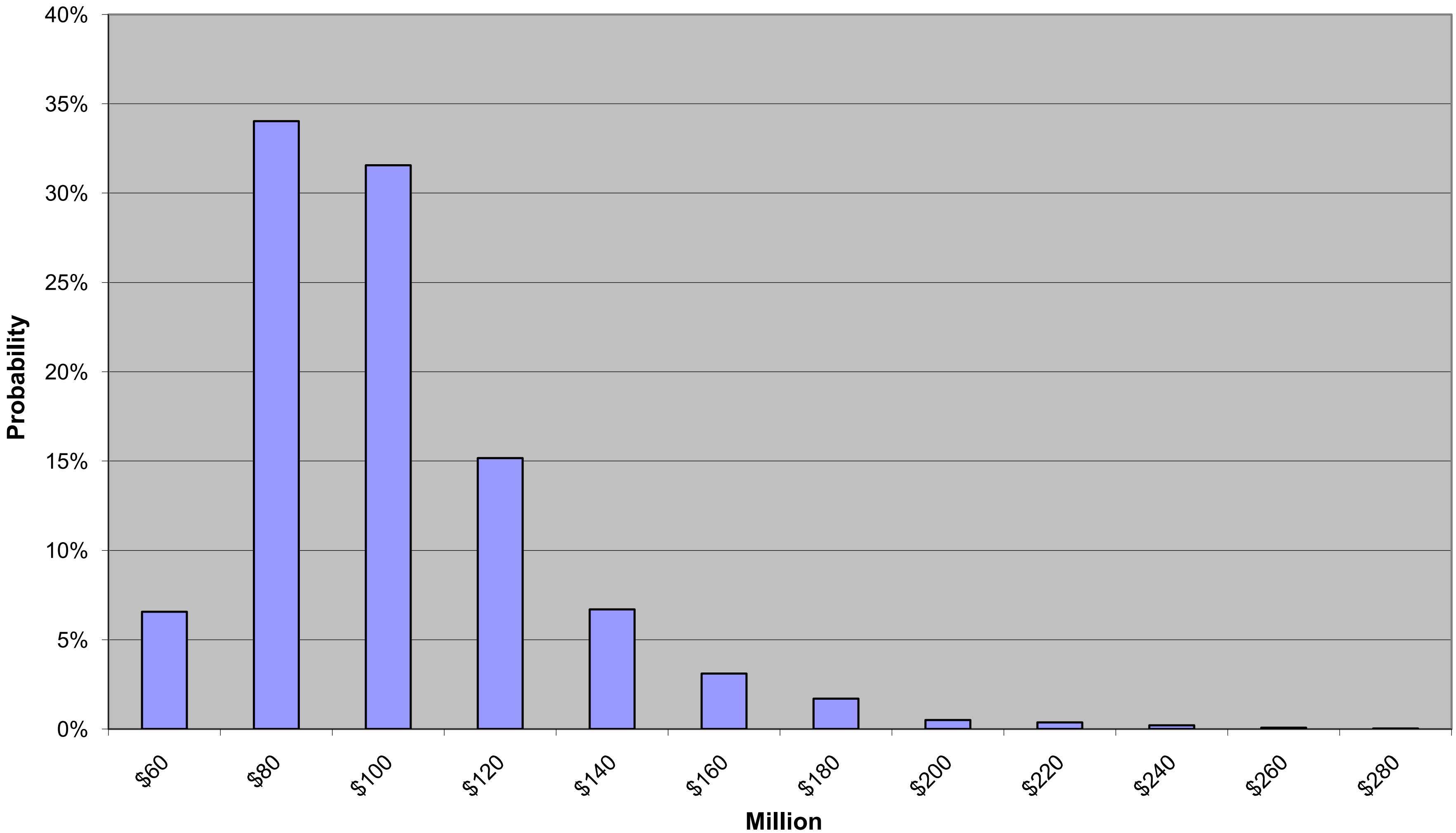
Graph 22: Simulated 4(h)(10)(C) Credits for FY 2007
(This graph is not applicable to the WP-07 Final Supplemental Proposal)



Graph 23: Simulated 4(h)(10)(C) Credits for FY 2008
(This graph is not applicable to the WP-07 Final Supplemental Proposal)



Graph 24: Simulated 4(h)(10)(C) Credits for FY 2009
(Updated from WP-07 Initial Supplemental Proposal)



1.17 Data Management Procedures (DMPs)

RiskMod receives data from a variety of sources and provides data to other computer models used in the rates process including AURORA, RAM2007, and ToolKit. Data are stored in two ACCESS databases, the Risk Input Database and the Risk Output Database. Figure 1 depicts a typical Risk Input Database and Figure 2 depicts a typical Risk Output Database. The computer applications used to move data between modules within RiskMod (*i.e.*, RiskSim, RevSim, and the Risk input and output databases) and also between RiskMod and other computer models are collectively referred to as Data Management Procedures (DMPs).

Figure 1: Typical Risk Input Database shown in Microsoft Access (No change from WP-07 Initial Supplemental Proposal)

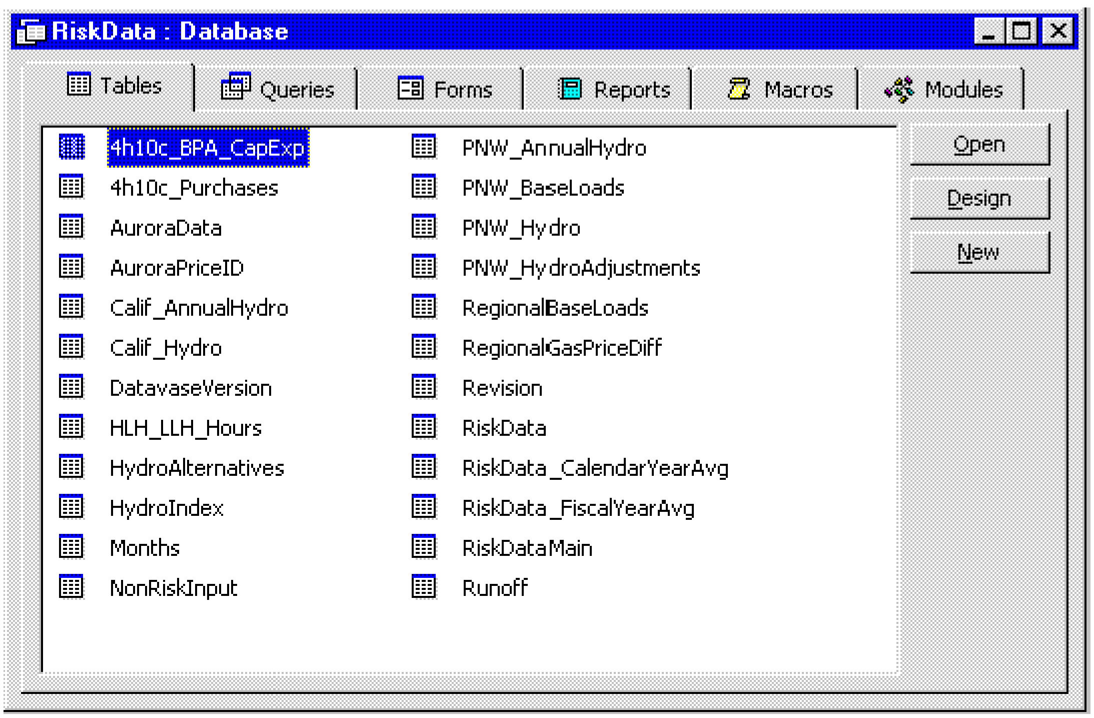
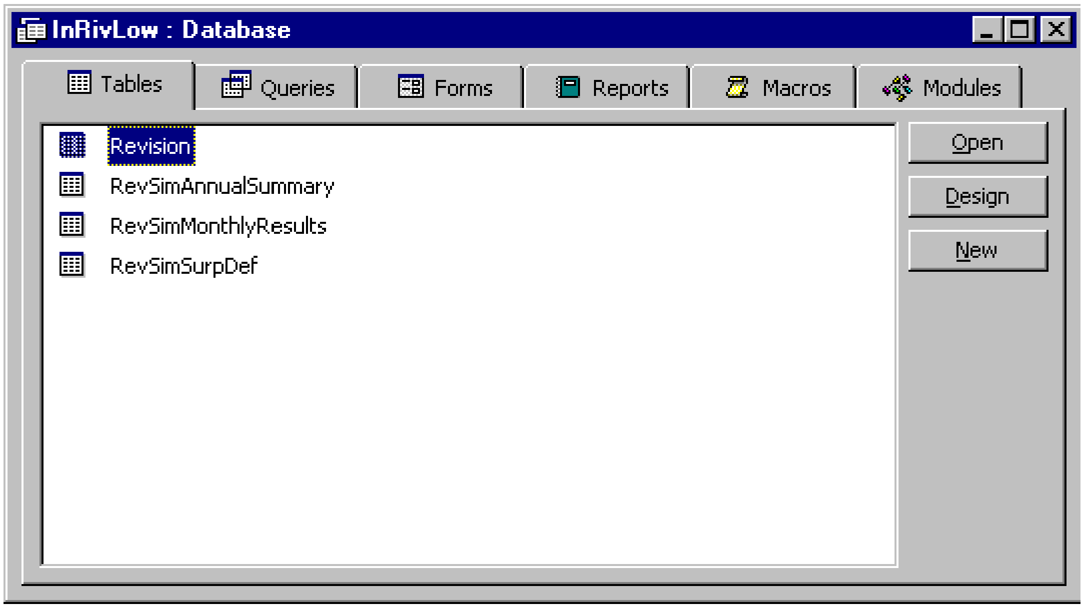


Figure 2: Typical Risk Output Database shown in Microsoft Access (No change from WP-07 Initial Supplemental Proposal)



1.17.1 DMPs For Deterministic Data

Deterministic data from the FY 2009 Load Resource Study, WP-07-FS-BPA-09, 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.

1.17.2 DMPs For Hydro Generation Data

Federal hydro generation data from the FY 2009 Load Resource Study, WP-07-FS-BPA-09, are downloaded as flat energy and HLH energy generation for each of the 50 water years. These data are used to calculate Federal HLH hydro generation ratios for each of the 50 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 are not included in the FY 2009 Load Resource Study, WP-07-FS-BPA-09, 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.

1.17.3 DMPs For Risk Data

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

1.17.4 DMPs For Interaction with AURORA

AURORA reads data from an input Access database and writes results to an output Access data base. This process is performed using scripting, which is a VB language built into AURORA that allows the user to run AURORA commands, run the commands of other applications (*i.e.,* Excel), and to build loops to repeat procedures.

1.17.4.1 AURORA Fifty (50) Water Year Run

The only data varied in the 50 Water Year Run of AURORA are PNW hydro generation (*see* Hydroregulation component of the FY 2009 Load Resource Study, WP-07-FS-BPA-09), which are reported in Table 3 of this Study Documentation. Data are supplied to AURORA 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 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 50 water years. The annual energy to capacity factor is calculated by dividing the PNW annual average hydro generation for each of the 50 water years (*see* FY 2009 Load Resource Study, WP-07-FS-BPA-09) by the PNW hydro capacity used in AURORA (*see* FY 2009 Market Price Forecast Study, WP-07-FS-BPA-11).

A link between the Excel workbook and the Access input file used by AURORA allows AURORA to read the data that is in the workbook. A macro is used to alter values in the Excel workbook as each of the simulations (*i.e.*, water years) is processed. The whole process is combined in a script file that runs AURORA, writes the output from AURORA to an Excel workbook, revises the input data used by AURORA for the next simulation, and then runs AURORA again. The script file contains a loop that repeats this procedure 50 times (once for each water year). Upon completion of this process, AURORA produces an Excel workbook containing monthly HLH and LLH spot market electricity prices for each of the 50 water years for three years, which the Data Manager loads into the Risk Input Database.

1.17.4.2 AURORA Risk Simulation Run

For the Risk Simulation Run of AURORA, variation in PNW and California loads and natural gas prices are considered along with variability in PNW and California hydro generation. *See* FY 2009 Market Price Forecast Study, WP-07-FS-BPA-11. AURORA is used to estimate HLH and LLH spot market electricity prices for 3000 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 50 Water Year Run. BPA created an Excel workbook which contains data for a single simulation that is refreshed with data from the Risk Input Database for each simulation. This workbook is called "RiskIn." The RiskIn workbook contains both VBA procedures and data for hydro generation, loads, and natural gas prices. The VBA procedures are designed so that they can be called by the VBA scripting within AURORA.

The modeling process for the Risk Simulation Run of AURORA is similar to that used for a 50 Water Year Run of AURORA. Scripting is used to call the VBA procedures in RiskIn, run AURORA, and write HLH and LLH spot market electricity prices to an Excel Workbook. The script file contains a loop that runs this procedure for 3000 simulations. Upon completion of the 3000 simulations, an Excel workbook receives HLH and LLH spot market electricity prices estimated by AURORA. These HLH and LLH spot market electricity prices are loaded into the Risk Input Database by the Data Manager.

1.17.5 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.*, 50 iterations for the 50 Water Year Run and 3000 iterations for the Risk Simulation Run. For each iteration, data are read which reflect the variability in PF loads, the output of CGS, variable wind generation, transmission expenses, DSI benefits, 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 the AURORA Model. Using these data, surplus energy sales and purchase amounts (aMW), surplus energy revenues and 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.

1.17.6 DMPs Between RiskMod, RAM2007, and ToolKit

Data transfers between these models are generally accomplished through Excel files or as manual data entry. Surplus energy revenues, power purchase expenses, and 4(h)(10)(C) credits are provided to RAM2007 as an Excel workbook generated from the Risk Output Database. *See* FY 2009 Wholesale Power Rate Development Study, WP-07-FS-BPA-13, regarding RAM2007. Rates from RAM2007 are manually entered into RevSim from a RAM2007 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 RAM2007.

1.18 Interaction Between RiskMod, RAM2007, and ToolKit to Calculate Rates

RiskMod is used in an iterative process with the RAM2007 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, power purchase expenses, and 4(h)(10)(C) credits in the 50 Water Year Run of RiskMod and input these data into RAM2007. With this information, RAM2007 calculates an initial set of rates for the rate period which is fed back to RevSim. RevSim is run and produces 3000 net revenues for each FY in the rate period. These results are input into ToolKit to calculate the amount of PNRR and other financial tools needed to achieve BPA's financial objectives.

1.19 Results

A statistical summary of the annual net revenues for FY 2008-2009 is reported in Table 42. Net revenues for FY 2008 are based on actual revenues and expenses for October 1, 2007 through July 31, 2008 and an assessment of the uncertainty in revenues and expenses for August and September 2008. Net revenues for FY 2009 are estimated by RiskMod using Proposed Rates with $0 million in PNRR. These values only represent the operational net revenues calculated in RiskMod and do not reflect additional net revenue adjustments in the ToolKit Model, such as the NORM output, interest earned on cash reserves, Cost Recovery Adjustment Clause (CRAC), and Dividend Distribution Clause (DDC).

Table 42: RiskMod Net Revenue Statistics (With PNRR of $0 million)
(Updated from WP-07 Initial Supplemental Proposal)

	FY 2007	FY 2008	FY 2009
Average		8,931	5,068
Median		5,210	3,990
Standard Deviation		35,628	362,816
1%		-68,495	-662,274
2.50%		-52,443	-613,778
5%		-41,449	-565,456
10%		-29,938	-511,518
15%		-22,592	-424,284
20%		-16,816	-338,260
25%		-11,837	-234,491
30%		-7,247	-169,273
35%		-3,768	-120,513
40%		-428	-77,833
45%		2,355	-41,845
50%		5,210	3,990
55%		7,764	46,243
60%		10,363	92,489
65%		12,635	138,607
70%		15,505	183,937
75%		19,520	238,048
80%		34,378	299,165
85%		47,432	368,692
90%		57,905	468,823
95%		75,017	616,926
97.50%		92,482	731,866
99%		115,592	915,045

2. NON-OPERATING RISK MODEL (NORM)

2.1 Methodology

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

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

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

with the values 1, 2, 3, 4, 5, and 6 in cells A1 to F1, and identical probabilities of 16.66…7 percent in each of the cells A2 to F2. When @RISK is run, each game will have a value for the function drawn randomly from the set of six possible values according to those probabilities. If 1,000 games are run, there should be about 167 games (1,000 / 6) where the value is 1, and about the same number with each of the other values. The actual number may vary slightly, but probably not by much. The larger the number of games, the more closely the actual count is likely to approach the expected number, which equals the probability times the number of games.

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

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

Some distributions in NORM are continuous probability distributions, such as the Normal probability distribution. For these, the *parameters* of the distribution of possible deviations are entered (*e.g.*, mean and standard deviation for the Normal distribution). For example, the annual generation at Grand Coulee is a factor in the calculation of payments under the Colville/Spokane

Settlement. Grand Coulee's annual generation cannot be known now, but is modeled in NORM. For calculating the FY 2009 Colville/Spokane Settlement payments, the annual generation at Grand Coulee is modeled as a Truncated Normal distribution with a mean of 22,183 GWh and a standard deviation of 3,003 GWh. The distribution is truncated, so that the annual generation will not exceed Grand Coulee's maximum historical generation of 28,615 GWh or fall below its minimum historical generation of 16,084 GWh. But the annual generation can take any value in-between the minimum and maximum. In each game, @Risk produces a number for the annual generation at Grand Coulee 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 22,183 GWh and standard deviation of 3,003 GWh. 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

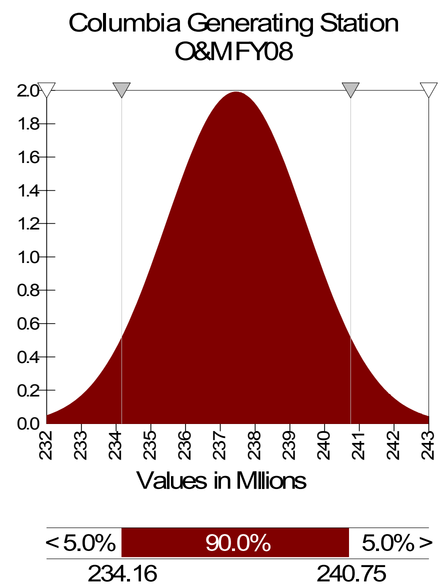
NORM models the risks of the generation function, as well as the risks of the Corporate costs which are the responsibility of the generation function. Transmission function risks are not included in the analysis, that is, the impacts of transmission function revenue uncertainty on BPA's financial picture 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 Section 2.2. The values in the probability distribution graphs and the statistical data accompanying those graphs in Section 2.2 are in millions of dollars. (The deviations are calculated by comparing the values in the distributions to the point values assumed elsewhere in the rate case (*e.g.*, the revenue requirement).)

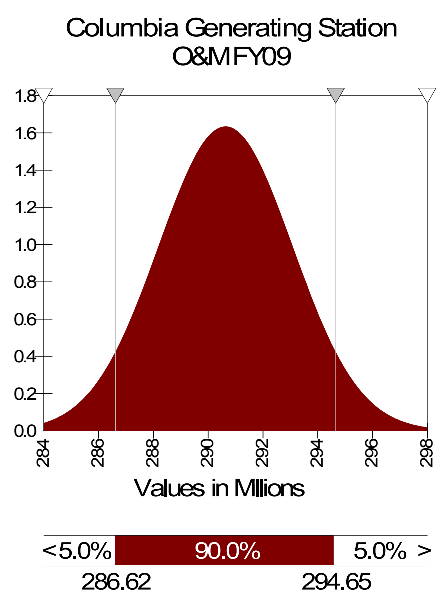
2.2 NORM Distributions

2.2.1 CGS O&M Distributions

Table 43: CGS O&M Distributions



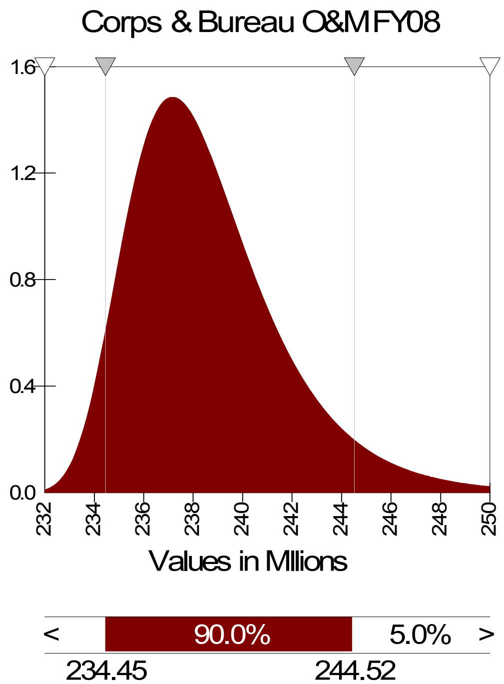
Minimum	$	231.0
5th Percentile	$	234.0
Median	$	237.6
95th Percentile	$	240.6
Maximum	$	241.9
Std. Dev	$	2.0
Final Proposal	$	238.1



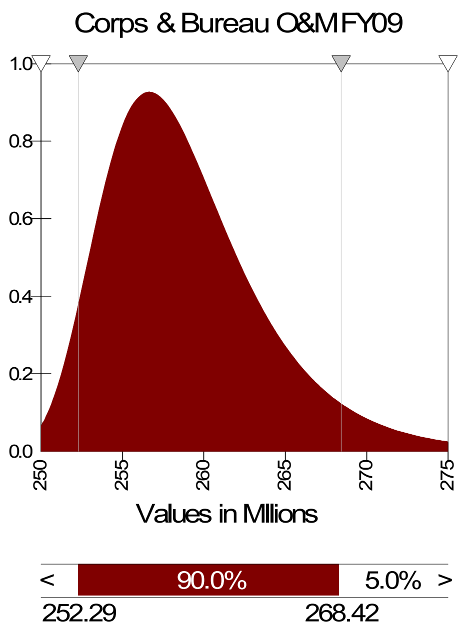
Minimum	$	279.2
5th Percentile	$	285.7
Median	$	291.3
95th Percentile	$	293.5
Maximum	$	294.6
Std. Dev	$	2.4
Final Proposal	$	292.9

2.2.2 COE and Bureau O&M Distributions

Table 44: COE and Bureau O&M Distributions



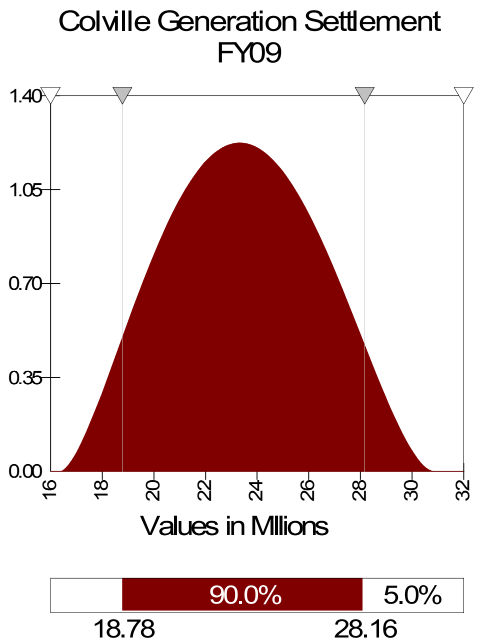
Minimum	$	233.1
5th Percentile	$	235.1
Median	$	237.4
95th Percentile	$	247.1
Maximum	$	277.6
Std. Dev	$	5.7
Final Proposal	$	238.5



Minimum	$	248.0
5th Percentile	$	252.4
Median	$	258.0
95th Percentile	$	268.7
Maximum	$	298.4
Std. Dev	$	6.4
Final Proposal	$	261.6

2.2.3 Colville Settlement Payment Distribution

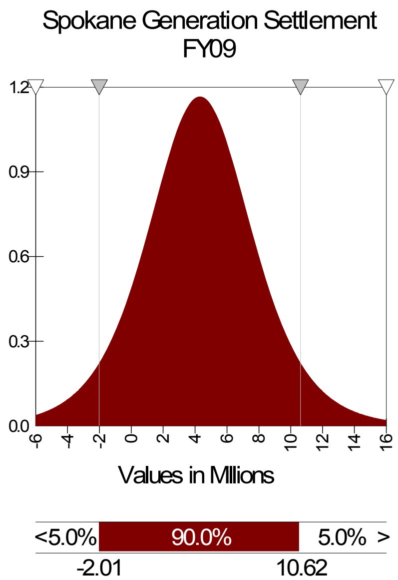
Table 45: Colville Settlement Payment Distribution



Minimum	$	17.0
5th Percentile	$	18.7
Median	$	23.4
95th Percentile	$	28.2
Maximum	$	30.2
Std. Dev	$	2.8
Final Proposal	$	20.9

2.2.4 Spokane Settlement Payment Distribution

Table 46: Spokane Settlement Payment Distribution



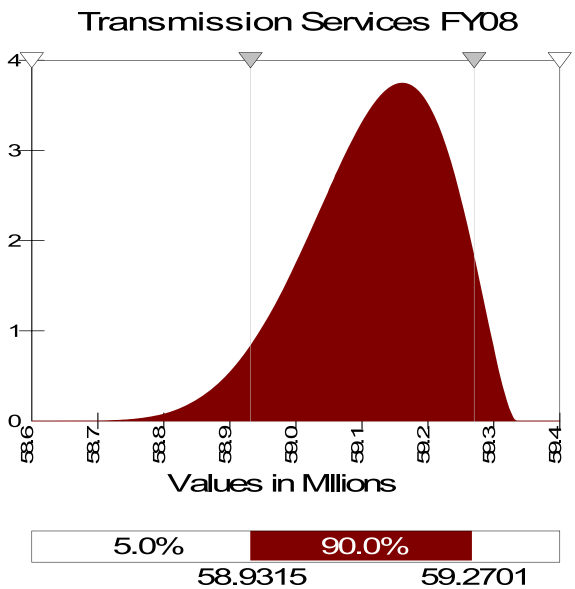
Minimum	$	-
5th Percentile	$	-
Median	$	5.9
95th Percentile	$	8.0
Maximum	$	8.7
Std. Dev	$	3.4
Final Proposal	$	-

2.2.5 Public Residential Exchange Cost Distributions

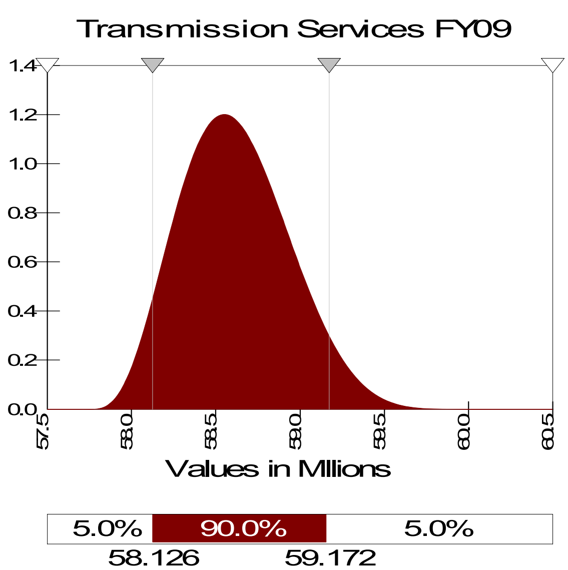
Uncertainty around Residential Exchange costs is not being modeled in NORM for the Supplemental Proposal.

2.2.6 Transmission Services Expense Distributions

Table 48: Transmission Services Expense Distributions



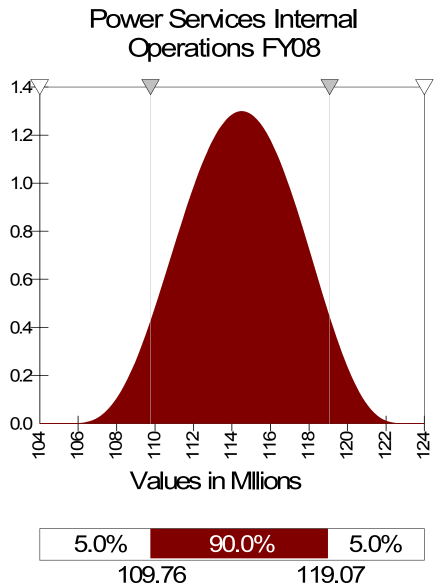
Minimum	$	58.8
5th Percentile	$	58.9
Median	$	59.1
95th Percentile	$	59.3
Maximum	$	59.3
Std. Dev	$	0.1
Final Proposal	$	59.0



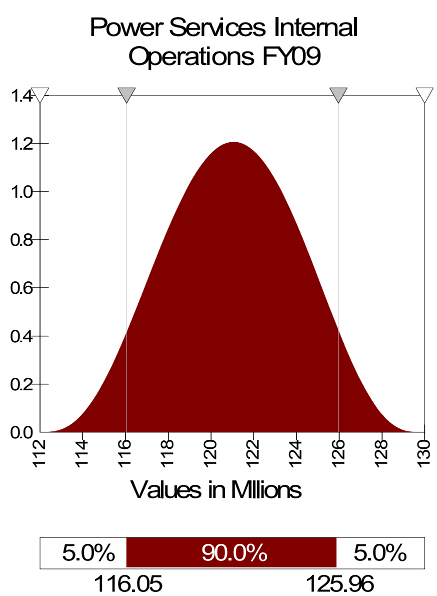
Minimum	$	57.8
5th Percentile	$	58.1
Median	$	58.6
95th Percentile	$	59.2
Maximum	$	59.7
Std. Dev	$	0.3
Final Proposal	$	58.2

2.2.7 Internal Operations Distributions

Table 49: Internal Operations Distributions



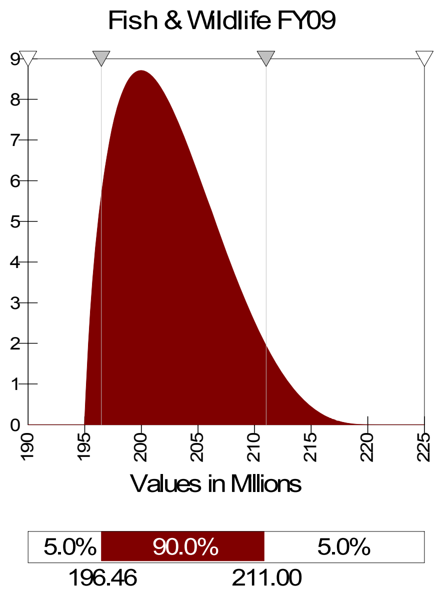
Minimum	$	106.1
5th Percentile	$	109.7
Median	$	114.4
95th Percentile	$	119.1
Maximum	$	122.0
Std. Dev	$	2.8
Final Proposal	$	114.4



Minimum	$	112.6
5th Percentile	$	116.0
Median	$	121.0
95th Percentile	$	125.9
Maximum	$	129.0
Std. Dev	$	3.0
Final Proposal	$	121.0

2.2.8 Fish and Wildlife Direct Program Expense Distributions

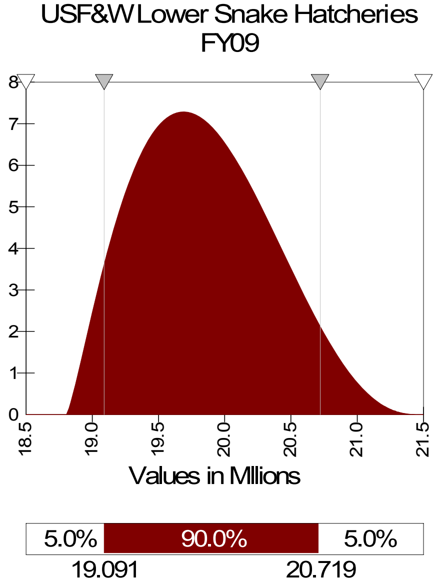
Table 50: F&W Direct Program Expense Distributions



Minimum	$	195.1
5th Percentile	$	196.5
Median	$	202.0
95th Percentile	$	211.0
Maximum	$	218.2
Std. Dev	$	4.5
Final Proposal	$	200.0

2.2.9 Lower Snake River Hatcheries Expense Distributions

Table 51: Lower Snake River Hatcheries Expense Distributions



Minimum	$	18.8
5th Percentile	$	19.1
Median	$	19.8
95th Percentile	$	20.7
Maximum	$	21.3
Std. Dev	$	0.5
Final Proposal	$	19.7

2.2.10 Borrowing and Inflation Rates

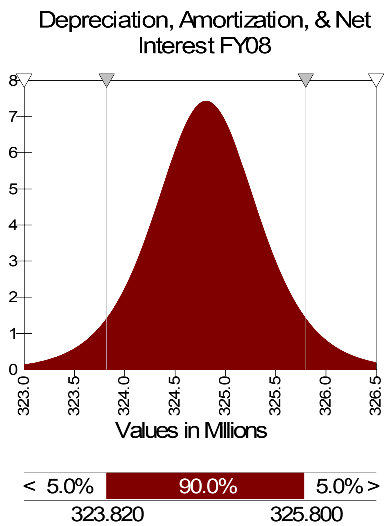
Table 52: Borrowing and Inflation Rates

2008	2008	2008	2008	2008	2008
5-Year Treas	14-Year Muni Tax Exempt	30-Year Approp	30-Year Treas	CPI Inflate	14-Year Muni Taxable
2.00	2.45	3.13	4.03	0.25	3.27
2.08	2.84	3.50	4.40	0.26	3.80
2.83	3.22	3.88	4.78	0.65	4.32
3.33	3.48	4.14	5.04	0.92	4.68
3.73	3.69	4.34	5.24	1.13	4.96
4.07	3.86	4.51	5.41	1.31	5.20
4.38	4.02	4.67	5.57	1.47	5.42
4.66	4.17	4.81	5.71	1.62	5.62
4.93	4.31	4.95	5.85	1.76	5.81
5.19	4.44	5.08	5.98	1.90	6.00
5.45	4.58	5.21	6.11	2.04	6.18
5.47	4.58	5.22	6.12	2.11	6.19
5.49	4.59	5.23	6.13	2.19	6.19
5.51	4.59	5.23	6.13	2.26	6.20
5.53	4.60	5.24	6.14	2.35	6.21
5.55	4.61	5.25	6.15	2.43	6.22
5.58	4.62	5.25	6.15	2.53	6.23
5.61	4.63	5.26	6.16	2.65	6.25
5.65	4.64	5.28	6.18	2.79	6.26
5.70	4.66	5.29	6.19	3.00	6.29
5.76	4.67	5.31	6.21	3.21	6.31

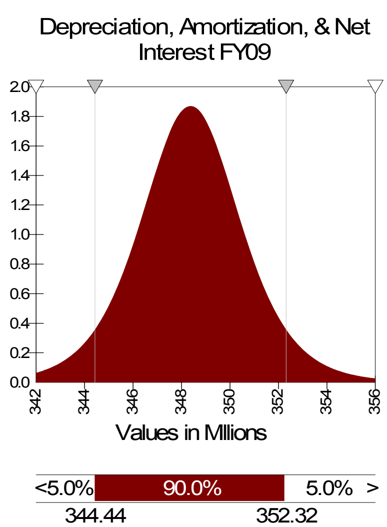
2009	2009	2009	2009	2009	2009
5-Year Treas	13-Year Muni Tax Exempt	30-Year Approp	30-Year Treas	CPI Inflate	13-Year Muni Taxable
1.79	2.88	3.45	4.35	0.70	3.87
2.50	3.22	3.83	4.73	0.75	4.33
3.22	3.55	4.21	5.11	1.01	4.80
3.70	3.78	4.46	5.36	1.18	5.11
4.08	3.97	4.66	5.56	1.32	5.36
4.41	4.12	4.84	5.74	1.44	5.58
4.70	4.26	4.99	5.89	1.54	5.77
4.97	4.39	5.14	6.04	1.64	5.95
5.23	4.52	5.28	6.18	1.73	6.12
5.48	4.63	5.41	6.31	1.82	6.28
5.73	4.75	5.54	6.44	1.91	6.44
5.76	4.77	5.55	6.45	1.94	6.46
5.78	4.78	5.57	6.47	1.97	6.48
5.81	4.80	5.59	6.49	2.00	6.50
5.84	4.81	5.60	6.50	2.03	6.53
5.88	4.83	5.62	6.52	2.06	6.55
5.91	4.85	5.64	6.54	2.10	6.58
5.95	4.88	5.66	6.56	2.14	6.61
6.01	4.91	5.69	6.59	2.20	6.65
6.09	4.95	5.73	6.63	2.28	6.71
6.17	4.99	5.78	6.68	2.36	6.77

2.2.11 Federal Depreciation, Amortization and Net Interest Distributions

Table 53: Federal Depreciation, Amortization and Net Interest Distributions



Minimum	$	323.5
5th Percentile	$	324.0
Median	$	324.8
95th Percentile	$	325.9
Maximum	$	326.7
Std. Dev	$	0.6
Final Proposal	$	324.7



Minimum	$	339.7
5th Percentile	$	343.7
Median	$	348.5
95th Percentile	$	351.7
Maximum	$	354.0
Std. Dev	$	2.4
Final Proposal	$	349.4

2.2.12 Annual Grand Coulee Generation

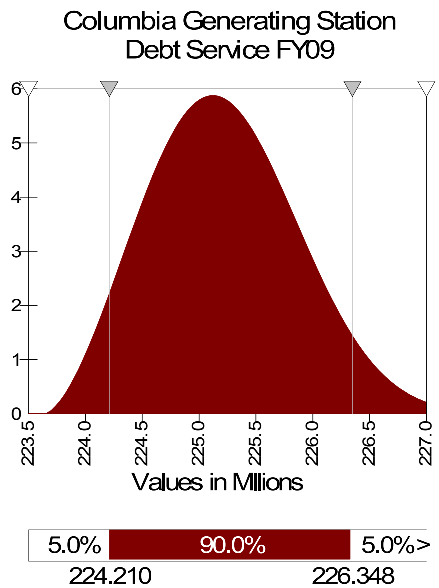
Table 54: Annual Grand Coulee Generation

Avg. MW	GWh
1,931	16,916
1,947	17,053
2,025	17,743
2,380	20,845
2,766	24,228
3,267	28,615
2,453	21,486
2,312	20,256
1,944	17,028
2,456	21,515
2,189	19,174
2,317	20,300
1,998	17,498
2,317	20,296
2,512	22,007
1,836	16,084
1,975	17,297
2,441	21,387
2,646	23,177
2,864	25,087
2,436	21,337
2,594	22,726
2,892	25,335
2,697	23,623
2,417	21,174
2,755	24,132
2,803	24,553
3,096	27,119
2,600	22,775
2,432	21,306
2,797	24,501
2,991	26,205
2,787	24,413
2,416	21,165
2,496	21,867
2,556	22,392
2,812	24,637
2,578	22,579
2,715	23,781
2,551	22,349
3,029	26,534
2,346	20,553
2,676	23,443
3,091	27,078
2,245	19,663
3,097	27,129
2,655	23,257
2,855	25,012
2,359	20,661
2,266	19,851

	GWh
Mean	22,183
Std. Dev.	3,003
Min	16,084
Max	28,615

2.2.13 CGS Debt Service Distributions

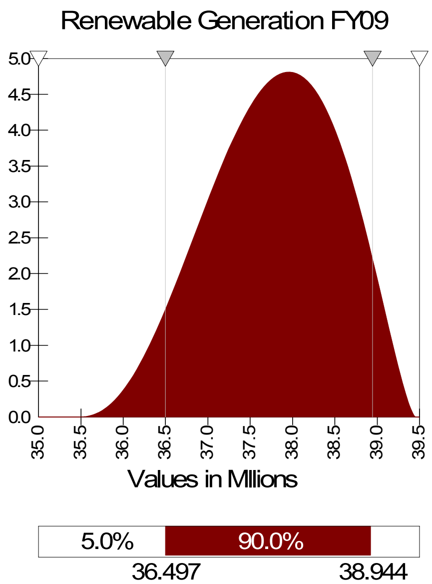
Table 55: CGS Debt Service Distributions



Minimum	$	223.7
5th Percentile	$	224.0
Median	$	225.7
95th Percentile	$	225.8
Maximum	$	225.8
Std. Dev	$	0.6
Final Proposal	$	225.5

2.2.14 Renewable Generation Distributions

Table 56: Renewable Generation Distributions



Minimum	$	35.6
5th Percentile	$	36.5
Median	$	37.8
95th Percentile	$	38.9
Maximum	$	39.4
Std. Dev	$	0.7
Final Proposal	$	38.0

3. TOOLKIT OUTPUT

3.1 Table 1: ToolKit Main

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R
1	ToolKit v. 2.40a, (12-14-2007)					Study title:	Final 09 RC run | PBL reserves											
2	Time of run: 13:47:13 on 9-11-08				1	-yr TPP =	99.20%	Run Type	PBL-only run									
3	Inputs	PBL data:	RM_WP07FS_FinalIter_updwTFCommitPurchExp_10-Sep-08.xls															
4		NORM dat	NORM_Data_08-Sep-08.xls															
5	Files =>	TBL data:																
6	Start in	Stop in	Run Type	CRAC	PBL	TBL	PBL Strt.	Add'l	Deferral		Sec. Rev. Rebate Description							
7	TK Year	TK Year	PBL	Lim/Total	LiqRes	LiqRes	ANR	LiqRes 7-9	Logic	n / a								
8	5	6	BPA	20,000	50	20	69.00											
9	Start TPP	"Small"	No. of	Starting	PBL Strt	TBL Strt	Debug	Reserves	AutoPrint	AutoPrint		Enable	CRAC	CRAC				
10	in TK Yr	Def. Size	Iterations	Iteration	Rsrv Bal	Rsrv Bal	Level	Graph	Res Grph	This Page		PNRR?	Fixed?	Stats On?				
11	6	$200	3,000	1	952.1	180												
12	ToolKit	Fiscal	Probabi-	Treasury	Amort	Interest	PBL Int.	TBL Int.	Other	TBL Rsrvs	Cash Lag	PBL Cash	TBL Cash					
13	Year	Year	listic?	Int. Rate	Sched	Sched	Cr. Sched	Cr. Sched	Cash Adj	Available	for PNRR	Tmg Adj	Tmg Adj					
18	5	2008	TRUE	5.46%	175.4	280.5	58.1				0.0	7.1						
19	6	2009	TRUE	5.46%	191.7	291.7	57.9			0.0	0.0	7.4						
20	ToolKit	Fiscal	Div. Dist.		CRAC			PNRR				TBL Fed.	PBL Fed.	Other NR	Delta			
21	Year	Year	Threshold	Lim/Year	Threshold	Lim/Year	Rev Basis	Shape	Risk Mod	Calc'd in TK	Sum	Int. Red.	Int. Red.	& Csh Adj	Int. Cred.			
26	5	2008	348.0	1,208	-32.0	300	1,351.6	0.00	0	0	0			0.0				
27	6	2009	270.7	1,222	-29.3	36	1,353.8	1.00	0	0	0			0.0				
28	Outputs																	
29	ToolKit	Fiscal	No. of	"Small"	1-year	Cumul.	Cumul.	Ave. Def.	Ave. Def.	Ave 1st	Ave. End.	Ave. End.	PNRR	PBL		Approx PF rates		
30	Year	Year	Deferrals	Deferrals	Probab.	Deferrals	Probab.	per Year	per Def.	Def./Def.	Reserves	PBL ANR	Added	Strt Bal		(average rates, not block)		
31														952.1		Base	After	After
32																	PNRR	Var.Rates
35	5	2008	0	-	100.0%	n / a	n / a	0.0	n / a	n / a	854.759	75	-					
36	6	2009	24	24	99.2%	24	99.2%	0.3	43.0	43.0	769.387	72	-					
39	ToolKit	Fiscal	Ave. DDC	Ave DDC	PF share	IOU Share	No. of	Ave DDC	Ave. CRAC	Ave CRAC	PF share	IOU Share	No. of	Ave CRAC	Ann.Lim.	Total Lim.	CRAC	
40	Year	Year	per each	per Year	of DDC	of DDC	DDCs	Rate	per each	per Year	of CRAC	of CRAC	CRACs	Rate	Reached	Reached	Freqncy	
45	5	2008		0	0	0	0	0.0%		0	0	0	0	0.0%	0	0	0%	
46	6	2009		0	0	0	0	0.0%	19	0	0	0	4	0.0%	1	0	0%	
49	ToolKit	Fiscal	NORM	PBL	TBL	A-T-C	Ave. Reb.	Ave Reb.	PF share	IOU Share	No. of	Ave. Re-	PBL Int	TBL Int	IOU Benefits After each calculation			
50	Year	Year	Inputs	Inputs	Inputs	Totals	per each	per Year	of Rebate	of Rebate	Rebates	bate Rate	Credit	Credit	Base	PNRR	Mkt Upd	Var.Rates
55	5	2008	0.0	8.9	0	-104			0	0		0.0%	42.5	0.0				
56	6	2009	-2.7	5.1	0	-82			0	0		0.0%	39.0	0.0				

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