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

September 2008

WP-07-FS-BPA-12

This page intentionally left blank

FY 2009 RISK ANALYSIS STUDY

TABLE OF CONTENTS

Page

This page intentionally left blank.

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
COU	Consumer-Owned Utiltity
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	Gigawatthour
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
MMBtu	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
NFB	***N***ational Marine Fisheries ***F***ederal Columbia River Power System ***B***iological Opinion
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
NWEC	Northwest Energy Coalition
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
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
PS	Power Services
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
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
TS	Transmission Services
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

This page intentionally left blank.

1. INTRODUCTION

1.1 Background

BPA's operating environment is filled with numerous uncertainties, and thus the rate setting process must take into account a wide spectrum of risks. BPA's rate setting process accounts for risks in two steps: in the risk analysis step, the distributions or profiles characterizing operating and non-operating risks are defined; and in the risk mitigation step, potential risk mitigation measures are tested to assess BPA's ability to recover its costs in the face of these uncertainties. RiskMod and the Non-Operating Risk Model (NORM) are used in the risk analysis step, and then the ToolKit is used to test the effectiveness of risk mitigation options. RiskMod and operating risks are discussed in Sections 2.1 through 2.4. The NORM and the non-operating risks are discussed in Section 2.5. The Toolkit and the active risk mitigation tools are discussed in Section 3 of this study.

The objective of the risk analysis is to identify, model, and analyze the impacts that key risks have on BPA's net revenue (revenues less expenses). The impacts of hydrosystem operating risks are quantified in RiskMod, and non-operating risks are quantified in NORM. The results from the Risk Analysis are subsequently used in the ToolKit to evaluate whether BPA is able to meet its Treasury Payment Probability (TPP) goal with the risk mitigation measures that are modeled in the ToolKit. These risk mitigation measures typically include starting financial reserves, the Cost Recovery Adjustment Clause (CRAC), Planned Net Revenues for Risk (PNRR), and the Dividend Distribution Clause (DDC). RiskMod also is used to calculate the average surplus energy revenues and power purchase expenses reported in the revenue forecast component of the FY 2009 Wholesale Power Rate Development Study, WP-07-FS-BPA-13.

RiskMod, NORM, and the ToolKit function together in the risk analysis to test that the rates are sufficient to provide a high probability that BPA can make its Treasury payments on time and in full during the rate period.

1.1.1 Operating and Non-Operating Risks

The two largest sources of financial uncertainty that BPA must address are the unpredictability of hydro conditions and of wholesale market prices. Uncertain hydro conditions and market prices cause volatility in BPA's net revenue that presents genuine challenges for BPA in its efforts to keep its power rates as low as possible while providing adequate assurance that BPA can meet its obligations to the U.S. Treasury. Approximately 80 percent of the power generated by BPA is hydro-based, and the total annual generation is a direct function of precipitation in the Columbia Basin. As a result, BPA has little control over the amount of available generation in any year. Increased wholesale market price volatility also contributes significantly to the risk and uncertainty facing BPA and its stakeholders. Higher, more volatile natural gas prices, a key factor in the pricing of electricity, increase the variability in BPA's net secondary revenues from year to year. As a result, BPA faces greater uncertainty over the level of net secondary revenues that will be available to meet its future financial obligations. These uncertainties are discussed in Section 2 of this study and in the accompanying documentation, WP-07-FS-BPA-12A.

Further financial uncertainty for BPA arises from the possibility of changes in program spending and river operations for fish mitigation. This risk is treated separately from operating risks and non-operating risks (*see* Section 3.4.1 of this study).

In the WP-07 Final Proposal studies, the variability of the Investor Owned Utility (IOU) Residential Exchange Program (REP) settlement benefits was modeled in the ToolKit. *See* Risk Analysis Study, WP-07-FS-BPA-04, at 24. 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 REP does not create as much financial uncertainty for BPA. Under BPA's proposed Average System Cost (ASC) Methodology, ASC levels will be determined prior to the final Supplemental Proposal, and a PF Exchange rate will be determined in the rate case, leaving only uncertainty over exchange loads. Most of the variability around IOU net REP benefit levels will be eliminated by BPA's treatment of the Lookback amounts. *See* Marks, *et al.*, WP-07-E-BPA-62. BPA is forecasting that three COUs will also participate in the REP in FY 2009. FY 2009 Wholesale Power Rate Development Study, section 8.

1.1.2 BPA's TPP Standard

By law, BPA's payments to Treasury are the lowest priority for revenue application, meaning that payments to Treasury are the first to be missed if revenues and financial reserves are insufficient to pay all bills on time. 16 U.S.C. § 839 e(a)(1). For this reason, BPA measures its potential for recovering costs in terms of probability of being able to make Treasury payments on time (Treasury Payment Probability, or TPP). The ToolKit is used to measure TPP in order to verify that BPA's rates provide a high probability that BPA can make its Treasury payments on time and in full during the rate period.

In its 1993 rate filing, BPA adopted a 10-Year Financial Plan which established a long-term policy for meeting its obligations for repaying the U.S. Treasury. 1993 ROD, WP-93-A-02, at 68-72. As this Plan was intended to be in effect until replaced, and it has not been replaced, it remains in effect. Two repayment probability goals were set in the 10-Year Financial Plan. The short-term goal was to ensure a 95 percent probability of making both of the annual Treasury payments in the two-year rate period on time and in full. *Id.* The longer-term goal was to maintain that 95 percent rate period standard for five consecutive two-year rate periods. *Id.* BPA continues to adhere to these 10-Year Financial Plan objectives for the WP-07 Supplemental Proposal, as affirmed in BPA's revised Financial Plan issued July 31, 2008. This TPP standard was established as a rate period standard; that is, it focuses upon the percentage of time BPA successfully makes all of its payments to Treasury over the entire rate period rather than setting numerical goals for year-to-year performance. *Id.* at 70.

This 95 percent two-year TPP standard was translated to an equivalent percentage for a one-year rate period by assuming that consecutive rate periods are statistically independent and that the one-year TPP standard should provide the same total probability of making both payments in two one-year periods as would be provided by one two-year period in which the 95 percent TPP standard is met. The desired one-year percentage is the square root of that 95%:

$$.95^{1/2} = .9747$$

This figure was rounded to 97.5 percent. To check, calculate the TPP for two consecutive one-year periods:

$$.975^{2} = .95063$$

The one-year TPP standard that is equivalent to the two-year 95 percent standard is 97.5 percent. Therefore, BPA is setting power rates to achieve a 97.5 percent probability that reserves available for risk attributed to Power Services will be sufficient to make its U.S. Treasury payments on time and in full over the one-year rate period.

1.2 Overview of the Risk Mitigation Package

The same objectives were used for the WP-07 Supplemental risk analysis as were used in the WP-07 analysis. BPA's policy objectives from the WP-07 risk mitigation package (*see* WP-07 Administrator's Final ROD, WP-07-A-02, section 2.9, at 5) include the following five objectives:

(1) A rate design that meets BPA financial standards, including meeting a 97.5 percent TPP (which is equivalent to a 95 percent two-year TPP).

(2) Lowest possible rates consistent with sound business principles, including statutory obligations.

(3) Lower, but adjustable, effective rates rather than higher, but stable, rates.

(4) A risk package that includes only those elements BPA believes can be relied upon.

(5) Reserve levels that are not built up to unnecessarily high levels.

It is important to understand that these objectives are interdependent and require BPA to balance these competing objectives against each other when developing its overall rate design strategy.

In the this study, BPA updated and analyzed its power risks and relied on the following risk tools designed to achieve the 97.5 percent TPP standard for the generation function. The following items are included in the calculation of the TPP.

(1) <u>Liquidity Reserve Level</u>. The liquidity reserve level increased from $50 million to $175 million and then lowered to $50 million to account for new sources of liquidity. A deferral of a Treasury payment is registered when reserves fall below this level of Liquidity Reserves defined for the generation function.

(2) <u>Starting Reserves Available for Risk Attributed to Power</u>. Starting financial reserves include cash in the Bonneville Fund and the deferred borrowing balance attributed to the generation function. The level of reserves available for risk attributed to the Power function at the beginning of FY 2008 was $952.1 million.

(3) <u>Cost Recovery Adjustment Clause</u>. The CRAC is an upward adjustment to the applicable requirements power rates published in the WP-07 Final Proposal. The adjustment is applied to power deliveries beginning in October following the fiscal year in which Power Services' Accumulated Modified Net Revenues (AMNR) fall

below the CRAC threshold. The AMNR threshold is set at the equivalent of $750 million in financial reserves attributed to Power Services.

(4) Dividend Distribution Clause. The DDC is a downward adjustment to the applicable requirements power rates published in the WP-07 Final Proposal. The adjustment is applied to power deliveries beginning in October following the fiscal year in which AMNR is above the DDC threshold. The AMNR threshold is set at the equivalent of $1,050 million in financial reserves attributed to Power Services.

Note that two tools included in the WP-07 Final Proposal are not included in this Supplemental Proposal:

(1) The Temporary Availability for Power Services' Rate Setting of Other Agency Reserves Is Not Included. The WP-07 Final Proposal assumed some reserves attributed to TBL (now Transmission Services) could be temporarily used by PBL (now Power Services) in FY 2007. This amount was calculated in the TBL 2006 rate case (TR-06); no similar amount was determined from TBL or Transmission Services rate cases for other years to be temporarily available to the Power function. No reserves attributed to TS in FY 2009 are assumed to be available to Power Services in FY 2009.

(2) Planned Net Revenues for Risk. PNRR is the last and final component of the revenue requirement that is added to annual expenses. By increasing the rate calculated from the revenue requirement, PNRR increases rates, which in turn increase financial reserves, thus increasing TPP until it meets the 97.5 percent TPP objective. No PNRR was necessary to meet the TPP objective for FY 2009.

Additional tools are also included in BPA's risk mitigation package, but are not modeled as part of the TPP analysis. These tools were not modeled because they are designed to recover the costs directly created by specific uncertainties that are also not modeled.

(1) NFB Adjustment. This adjustment increases the annual maximum recovery amount (Cap) on the CRAC applicable to FY 2009 rates to allow recovery of increased costs or reduced revenues resulting from court-ordered changes to FCRPS hydro operations, agreements resolving issues in the FCRPS BiOp litigation, and/or any decrease in net revenue due to a new BiOp should such changes occur in FY 2008. The NFB Adjustment does not directly modify rates.

(2) Emergency NFB Surcharge. This surcharge is a separate mechanism from the NFB Adjustment, but it triggers based on the same events, with the added requirement that the Agency Within-Year TPP be less than 80 percent. The NFB Surcharge addresses the fact that the CRAC does not produce revenues in the same fiscal year in which the financial circumstances causing the CRAC to trigger occur. The NFB Surcharge is designed to recover NFB costs (or lost revenues) in the same year when BPA's financial reserves are precariously low. It can apply to FY 2008 rates if (a) BPA's within-year TPP is below 80% in FY 2009, and also (b) a triggering event occurs in FY 2009.

Information regarding these features is discussed in Section 3 of this study, the FY 2009 Wholesale Power Rate Development Study (WPRDS) (WP-07-FS-BPA-13), and the FY 2009 General Rate Schedule Provisions (GRSPs) (WP-07-A-BPA-05A).

2. RISK ANALYSIS

BPA's traditional approach to modeling risks is to use *Monte Carlo* simulation methodology. In this technique, the models RiskMod, NORM, and ToolKit run through 3,000 *games* or scenarios. In each game, each of the financial uncertainties is randomly assigned a value based on input specifications for that uncertainty. After all of the games have been run, the output data of the set of games is analyzed and summarized in various ways, or passed to other tools.

2.1 RiskMod

RiskMod is comprised of a set of risk simulation models, collectively referred to as RiskSim; a set of computer programs that manage data referred to as Data Management Procedures; and RevSim, a model that calculates net revenues. RiskMod interacts with AURORA, the Rates Analysis Model (RAM2007), and the ToolKit model during the process of performing the Risk Analysis Study. AURORA is the computer model 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 used to calculate rates (*see* WPRDS, WP-07-FS-BPA-13), and ToolKit is the computer model used to develop the risk mitigation package that achieves BPA's TPP standard. *See* Section 3 of this study regarding the ToolKit model.

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 initial WP-07 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 2.4.8 of this Study, 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 2.4.8 in this Study, regarding why variable PF rates for FY 2009 were not computed in the ToolKit Model for the WP-07 Final Supplemental Proposal.

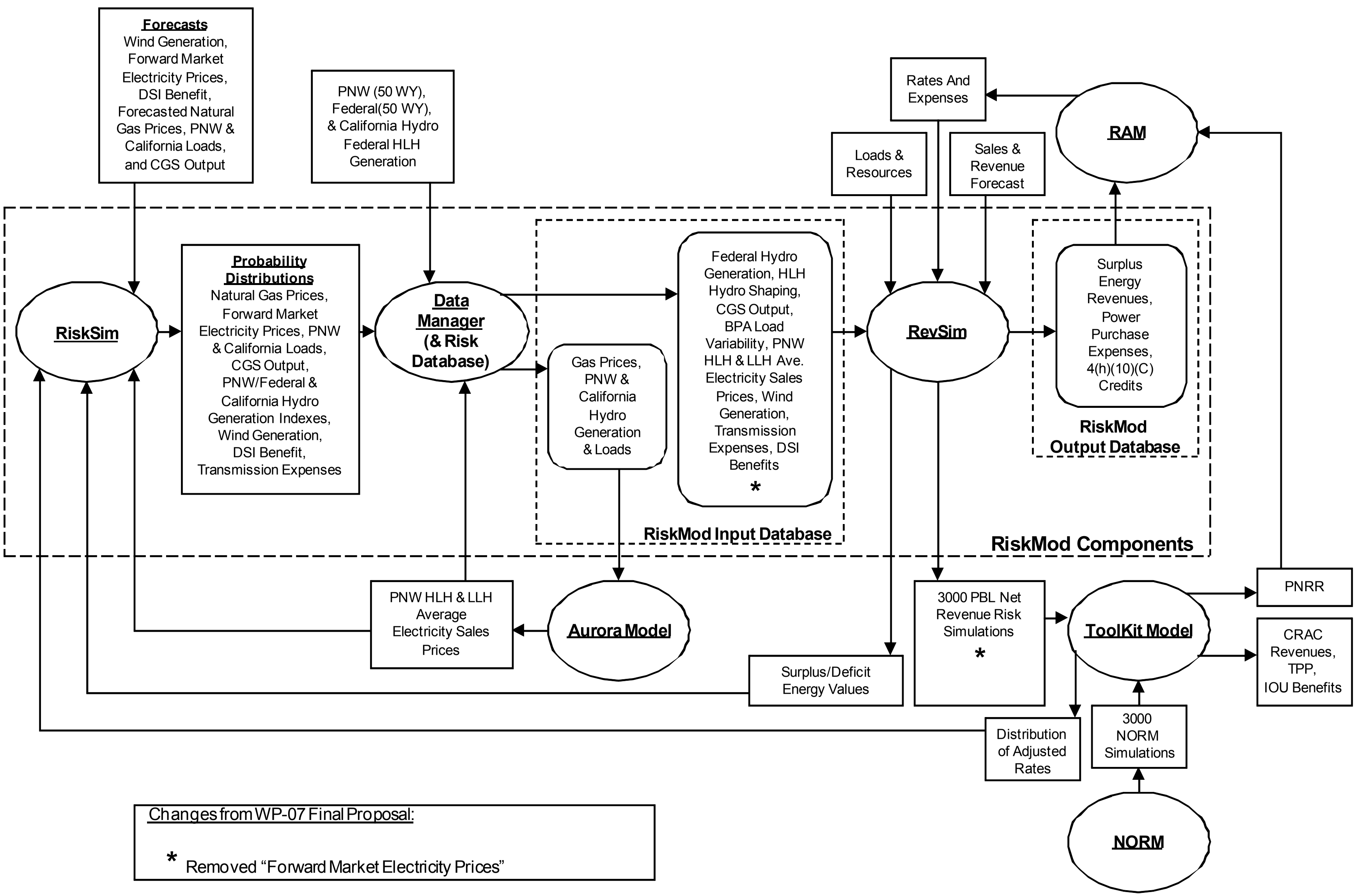
The Supplemental Proposal uses the same methodology for calculating net revenues (RevSim) as was used in the WP-07 Final Proposal, with data updates for FY 2008-2009. Data updates to loads and resources from the FY 2009 Load Resource Study, WP-07-FS-BPA-09, include a revised assignment of monthly hours to heavy load hours (HLH) and light load hours (LLH) to be consistent with the HLH/LLH assignment used in the Load Resource Study. Other data updates are revenues from the Revenue Forecast component of the FY 2009 WPRDS, WP-07-FS-13, and rates and expenses from RAM2007.

Variations in monthly loads, resources, natural gas prices, forward market electricity prices, transmission expenses, and aluminum smelter benefit payments are simulated in RiskSim. Monthly spot market electricity prices based on simulated loads, resources, and natural gas prices are estimated by AURORA. Data Management Procedures facilitate the formatting and movement of data that flow to and/or from RiskSim, AURORA, and RevSim. RevSim uses 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 WPRDS, WP-07-FS-BPA-13, and rates and expenses from the RAM2007 to estimate net revenues.

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. Heavy Load Hour (HLH) and Light Load Hour (LLH) surplus energy values from RevSim are used in the

Transmission Expense Risk Model. 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 for the one-year rate period. The processes and interaction between the models and studies are depicted in Graph 1. Additional discussion on these processes and interactions is provided in the FY 2009 Risk Analysis Study Documentation (Documentation), WP-07-FS-BPA-12A.

Graph 1: RiskMod Risk Analysis Information Flow



Changes from WP-07 Final Proposal:

* Removed “Forward Market Electricity Prices”

2.2 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. *See* the Revenue Forecast component of the FY 2009 WPRDS, WP-07-FS-BPA-13; the FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10; and discussion of AURORA in the FY 2009 Market Price Forecast Study, WP-07-FS-BPA-11.

The monthly outputs 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 WPRDS, Revenue Requirement Study, and AURORA. *Id*. Loads, resources, and natural gas price risk data for each simulation are input into AURORA to estimate monthly HLH and 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 is used to calculate net revenues in RevSim.

The risk models run 3,000 games to produce monthly risk data for the FY 2009 rate period. Thus, each of the risk models produces 3,000 rows and 12 columns of simulated data.

2.3 @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 reflects the specific risk, providing the necessary parameters required for developing the probability distribution, and letting @RISK sample values from the probability distributions based on the parameters provided. The values sampled from the probability distributions reflect their relative likelihood of occurrence. The parameters required for appropriately capturing risk are not developed in @RISK, but are developed in analyses external to @RISK.

2.4 Operational Risk Factors

In the course of doing business, BPA manages risks that are unique to operating a hydro system as large as the Federal Columbia River Power System (FCRPS). The variation in hydro generation due to the volume of water supply from one year to the next can be substantial. BPA also faces other operational risks and variability that increase BPA's risk exposure, including the following: (1) load variability due to changes in load growth and weather; (2) nuclear plant (Columbia Generating Station) generation; (3) wind generation and value of output; (4) transmission expenses; (5) DSI benefit levels; 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.

In regard to hydro operations, details of the power and non-power requirements, including consideration of operations under the 2008 FCRPS BiOp, for the hydro regulation study for FY 2009 are presented in the FY 2009 Load Resource Study Documentation, WP-07-FS-BPA-09A. For additional information on how BPA intends to respond to BiOp uncertainty, *see* Section 3 of this study.

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

2.4.1 Pacific Northwest (PNW) and Federal Hydro Generation Risk Factors

The PNW and Federal hydro generation risk factors reflect the uncertain effects of the timing and volume of streamflows on monthly PNW and Federal hydro generation under specified hydro operation requirements. Federal hydro generation risk is accounted for in this rate filing in RevSim in two ways. *See* Documentation, WP-07-FS-BPA-12A.

For FY 2009, hydro generation risk was accounted for by inputting monthly hydro generation data estimated by the HydroSim Model for monthly streamflow patterns experienced from October 1928 through September 1978 (also referred to as the 50 water years). These monthly hydro generation data are developed by simulating hydro operations sequentially over all 600 months of the 50 water years. This analysis by HydroSim is referred to as a continuous study. *See* the Hydro-regulation component of the FY 2009 Load Resource Study, WP-07-FS-BPA-09 regarding HydroSim, continuous study, and 50 water years. These hydro generation values were updated from the WP-07 Final Proposal.

Hydro generation adjustments were made to each year of the 50-water-year data from the continuous study for FY 2009 to reflect the refilling of non-treaty storage in Canada. These hydro generation adjustments for FY 2009 were updated from the WP-07 Final Proposal.

In this WP-07 Final Supplemental Proposal, the PNW and Federal hydro generation data are used to estimate prices and revenues for 3,000 one-year simulations (FY 2009). The monthly Federal hydro generation data are input into the RevSim Model to quantify the impact that Federal hydro generation variability has on BPA's net revenues. The associated monthly PNW hydro generation data are input into AURORA to quantify the impact that PNW hydro generation has on PNW electricity prices. Each simulation uses hydro generation from a one-year streamflow pattern in the continuous study for FY 2009. The water year for each iteration is randomly sampled from 1929 through 1978, using a uniform distribution. Prices and net revenues are estimated based on each of the 50 water years being sampled 60 times to produce 3,000 one-year simulations.

Higher streamflows usually increase surplus energy revenues and decrease purchased power expenses. Surplus energy revenues usually increase because the larger quantities of surplus energy available for sale more than compensate for the lower market prices. Conversely, lower streamflows usually decrease surplus energy revenues and increase purchased power expenses. Surplus energy revenues usually decrease because the smaller quantities of surplus energy available for sale are not offset by higher market prices.

2.4.2 PNW and BPA Load Risk Factor

This risk factor reflects the impacts that the strength of the economy and fluctuations in temperature has on HLH and LLH spot market prices and Priority Firm Power (PF) loads. The level of economic activity impacts the overall annual amount of load placed on BPA by its PF customers, while fluctuations in load due to weather conditions cause monthly variation in loads, especially during the winter, when heating loads are highest. Load growth variability and load variability due to weather for the PNW (and indirectly for BPA) are simulated in the PNW Load Risk Model. *See* Documentation, WP-07-FS-BPA-12A. Annual load growth variability parameters were derived from historical load data from the Western Electricity Coordinating Council (WECC, formerly called the WSCC). *See* Documentation, WP-07-FS-BPA-12A. Monthly load variability for the PNW (and indirectly for BPA) was derived from daily load variability parameters used as input data in the Power Market Decision Analysis Model (PMDAM) in the 1996 rate case. *See* Marginal Cost Analysis Study, WP-96-FS-BPA-04, and Documentation, WP-07-FS-BPA-12A.

Higher-than-expected firm loads due to economic and weather conditions increase PF loads and revenues, increase power purchase expenses, and reduce surplus energy revenues. Lower-than-expected firm loads reduce PF loads and revenues, decrease power purchase expenses, and increase surplus energy revenues. Higher spot market electricity prices increase both BPA's surplus energy revenues and power purchase expenses. Conversely, lower spot market electricity prices decrease both BPA's surplus energy revenues and power purchase expenses.

2.4.3 California Hydro Generation Risk Factor

This risk factor reflects the uncertain effects of the timing and volume of streamflows on monthly hydro production in a given year in California. This uncertainty was derived from monthly hydro production data reported by the Energy Information Administration for 1980-1997. *See* Documentation, WP-07-FS-BPA-12A.

Higher California hydro generation generally reduces the need to run thermal plants in California, which results in lower prices paid by California utilities for PNW surplus energy and lower prices paid by PNW utilities for purchased power from California. Conversely, lower hydro generation generally increases the need to run thermal plants in California, which results in higher prices paid by California utilities for PNW surplus energy and higher prices paid by PNW utilities for purchased power from California.

2.4.4 California Load Risk Factor

This risk factor reflects the impacts that the strength of the economy and fluctuations in temperature has on California loads and HLH and LLH spot market electricity prices. The level of economic activity impacts the overall annual amount of loads in California while fluctuations in load due to weather conditions cause monthly variation in loads, especially during the summer, when cooling loads are highest. Load growth variability and load variability due to weather for California are simulated in the California Load Risk Model. *See* Documentation, WP-07-FS-BPA-12A. Annual load growth variability parameters are derived from historical WECC load data. *See* Documentation, WP-07-FS-BPA-12A. Monthly load variability for California are derived from daily load variability parameters used as input data in PMDAM in the 1996 rate case. *See* Marginal Cost Analysis Study, WP-96-FS-BPA-04, and Documentation, WP-07-FS-BPA-12A.

Higher California loads increase the need to run thermal plants in California, which results in higher prices paid by California utilities for PNW surplus energy and higher prices paid by PNW utilities for purchased power from California. Conversely, lower California loads decrease the need to run thermal plants in California, which generally results in lower prices paid by California utilities for PNW surplus energy and lower prices paid by PNW utilities for purchased power from California.

2.4.5 Natural Gas Price Risk Factor

This risk factor reflects the uncertainty in the costs of producing electricity from gas-fired resources throughout the WECC region. Natural gas price risk is simulated in the Natural Gas Price Risk Model, and the associated spot market electricity prices are estimated in AURORA. *See* Documentation, WP-07-FS-BPA-12A and FY 2009 Market Price Forecast Study, WP-07-FS-BPA-11.

Higher gas prices generally increase the cost of producing electricity from gas-fired resources, which increases the price of electricity on the wholesale power market. Conversely, lower gas prices generally decrease the cost of producing electricity from gas-fired resources, which decreases the price of electricity on the wholesale power market.

Higher gas prices tend to result in BPA earning higher surplus energy revenues and paying higher purchased power expenses. Likewise, lower gas prices tend to result in BPA earning lower surplus energy revenues and paying lower purchased power expenses.

2.4.6 Nuclear Plant Generation Risk Factor

This risk factor is modeled in the Columbia Generating Station (CGS) Nuclear Plant Risk Model and reflects the uncertainty in the amount of energy generated by the CGS. *See* Documentation, WP-07-FS-BPA-12A. Quantification of this risk is such that the average of the simulated outcomes is equal to the expected monthly CGS output specified in the FY 2009 Load Resource Study, WP-07-FS-BPA-09. The potential values of the results simulated can vary from the output capacity of the plant to zero output.

Higher-than-expected CGS generation tends to increase BPA's surplus energy revenues or reduce its power purchase expenses, because more energy is available for either making surplus energy sales or displacing power purchases. Lower-than-expected nuclear plant generation tends to decrease BPA's surplus energy revenues or increase its power purchase expenses, because less energy is available for either making surplus energy sales or displacing power purchases.

2.4.7 IOU Residential Exchange Program Settlement Benefits Risk Factor

As noted in Section 1.1.1, the variability of IOU REP settlement benefits was modeled in the ToolKit for the WP-07 Final Proposal because the expense of the benefits varied with market prices and represented a significant financial uncertainty to BPA. As the settlement was overturned by the Ninth Circuit, BPA is proposing a different structure, a REP, in which the benefits are not dependent on market prices, and in which the benefits do not pose a significant financial uncertainty for BPA. They are therefore not modeled.

2.4.8 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, and the DSI Supplemental Administrator's Record of Decision, signed May 31, 2006, 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 a rate slightly above 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. *See* Documentation, WP-07-FS-BPA-12A.

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 five-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 WP-07 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.

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 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* FY 2009 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.

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 of this Study, 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 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.

2.4.9 Wind Resource Risk Factor

This risk factor, which is quantified in both risk simulation models and RevSim, 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. *See* Documentation, WP-07-FS-BPA-12A. The wind generation risk is quantified 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 average of the simulated monthly generation outcomes for each wind project closely approximates the expected monthly generation values included in the FY 2009 Load Resource Study, WP-07-FS-BPA-09. 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.

Higher wind generation yields higher net revenues when wholesale electricity prices are greater than the purchase prices specified in output contracts, and lower net revenues when wholesale electricity prices are less than the purchase prices specified in output contracts. Contrastingly, lower wind generation yields relatively lower net revenues when wholesale electricity prices are greater than the purchase prices specified in output contracts, and relatively higher net revenues when wholesale electricity prices are less than the purchase prices specified in output contracts.

2.4.10 Transmission Expense Risk Factor

This risk factor reflects the uncertainty in Power Services transmission and ancillary expenses, relative to the expected expenses included in the Revenue Requirement when proposing rates. *See* FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10**.** The risk exposure of this factor, which is computed in the Transmission Expense Risk Model, is based on variability in surplus energy sales with the probability distributions for these expenses being asymmetrical, since it reflects how transmission and ancillary services expenses vary from the cost of the fixed, take-or-pay, firm transmission capacity that the Power Services has under contract, which must be paid for regardless of whether it is used. Because Power Services has more firm transmission capacity under contract than it has firm contract sales, in this model Power Services 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. *See* Documentation, WP-07-FS-BPA-12A.

Under conditions where Power Services sells more energy than it has firm transmission rights, transmission and ancillary services expenses will increase. Alternatively, under conditions where Power Services sells less energy than it has firm transmission rights, transmission expenses will remain unchanged, but ancillary services expenses will decline.

2.4.11 4(h)(10)(C) Credit Risk Factor

This risk factor is quantified in RevSim and reflects the uncertainty in the amount of 4(h)(10)(C) credits BPA is allowed to credit against its annual U.S. Treasury payments. *See* Documentation, WP-07-FS-BPA-12A. The 4(h)(10)(C) credit is the method by which BPA implements a provision in the 1980 Pacific Northwest Electric Power Planning and Conservation Act that allows BPA to be reimbursed on a system wide basis for fish and wildlife expenditures it makes on behalf of the non-power purposes of the Federal hydro projects. BPA reduces its annual Treasury payment by the amount of the credit. The amount of the 4(h)(10)(C) credits that BPA can take for each of the 50 water years for FY 2009 is determined by summing the costs of the operational impacts (power purchases) and the expenses and capital costs associated with BPA's fish and wildlife mitigation measures, and then multiplying the total cost by 0.223 (22.3 percent representing the non-power purpose percentage of the FCRPS). *See* FY 2009 Load Resource Study, WP-07-FS-BPA-09. The direct program expenses and capital costs for FY 2009 do not vary by water year and are documented in the FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10.

The costs of the operational impacts are calculated for each of the 50 water years in RiskMod for FY 2009 by multiplying spot market electricity prices from AURORA by the amounts of power purchases (aMW) that qualify for 4(h)(10)(C) credits. The amounts of power purchases (aMW) that qualify for 4(h)(10)(C) credits are 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 power purchases associated with the 4(h)(10)(C) credits is contained in the FY 2009 Load Resource Study Documentation, WP-07-FS-BPA-09A.

Higher-than-expected 4(h)(10)(C) credits, which normally occur under below-average streamflow conditions because the amounts of power purchases that qualify for 4(h)(10)(C) credits are larger, increase net revenues during drier streamflow conditions. Conversely, lower-than-expected 4(h)(10)(C) credits, which normally occur under above-average streamflow conditions because the amounts of power purchases that qualify for 4(h)(10)(C) credits are smaller, decrease net revenues during the wetter streamflow conditions.

2.4.12 RevSim Analysis

The RevSim module within RiskMod serves two main functions in determining rates. The first function (the 50-Water-Year Run) is to calculate secondary energy revenues and 4(h)(10)(C) credits that are used by the RAM2007 model. The second function (the Risk Simulation Run) is to simulate Power Services' operational net revenue risk. *See* Documentation, WP-07-FS-BPA-12A. Inputs to RevSim include risk data simulated by RiskSim and AURORA, 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 WPRDS, WP-07-FS-BPA-13, and the RAM2007.

The risk data simulated by RiskSim and monthly spot market electricity prices estimated by AURORA are used to calculate 3,000 net revenues in RevSim for FY 2009, which are provided to the ToolKit model to calculate TPP. *See* Section 3 of this study, regarding the ToolKit model.

Net revenues for FY 2008 are based on actual revenues and expenses through July 31, 2008 and an estimate of the variability of revenues and expenses for August and September 2008. The variability in net revenues for August and September 2008 captures the uncertainty in starting reserves for the FY 2009 rate period.

2.4.13 Results from RiskMod

RiskMod results are typically used in an iterative process with the ToolKit model and the RAM2007 to calculate PNRR and, ultimately, rates that are sufficient to meet the 97.5 percent

TPP standard for a one-year rate period. The net revenues estimated for each RiskMod run depend on the level of the rates developed by the RAM2007 at different levels of PNRR. RiskMod estimates several temporary, intermediate sets of net revenues during the iterative process of trying to develop rates that meet the 97.5 percent TPP standard. The final set of net revenues from RiskMod is the set that meets the 97.5 percent TPP standard. This iterative process was used in the WP-07 Final Proposal. However, this iterative process was not performed in the Supplemental Proposal because BPA is proposing not to use PNRR.
The net revenue risk estimated by RiskMod is input into the ToolKit model. The ToolKit model uses the net revenue risk estimated by RiskMod, the net revenue risk estimated by the NORM model, and additional adjustments to net revenues from interest earned on cash reserves, to calculate CRACs, DDCs, PNRR, and TPP. *See* Sections 2.5 and 3 of this study, regarding NORM and the ToolKit model.

A statistical summary of the annual net revenues for FY 2009 estimated by RiskMod using rates with $0 million in PNRR is reported in Table 1. Net revenues for FY 2009 average $5.1 million. These values only represent the operational net revenues calculated in RiskMod. They 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). *See* Sections 2-3 of this study, regarding NORM and the ToolKit model. Also, the average net revenues in Table 1 will differ from the net revenues shown in Table 8A of the FY 2009 Revenue Requirement Study, WP-07-FS-BPA-10, which represents a deterministic forecast that does not account for the impact of risks.

Table 1: 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

Surplus energy sales revenue, balancing power purchase expense, and section 4(h)(10)(C) credits from the 50-water-year run of RiskMod for FY 2010-2013 are also provided to the RAM2007 to inform the 7(b)(2) rate test. *See* FY 2009 7(b)(2) Rate Test Study, WP-07-FS-BPA-14.

2.5 Non-Operating Risk Model (NORM)

NORM is an analytical risk tool that was developed to capture risks other than operational risks in the rate setting process. It was first introduced as part of the WP-02 Power Rate Proposal. NORM models the non-operating risks of the generation function, as well as the risks of the corporate costs that are covered by the generation function. Transmission function risks are not included in the analysis except that NORM includes the Power function expense uncertainty for transmission services. NORM does model some changes in revenue, and some changes in cash flow (NORM, the Accrual-to-Cash Adjustment, and the ToolKit all distinguish between net revenue and cash flow; *see* Section 2.5.3.13). Whereas RiskMod is used to quantify risks having to do with various economic and generation resource capability variations (generally risks related to physically operating the power system), NORM is used to model risks surrounding projections of non-operations-related revenue or expense levels associated with the generation function in the revenue requirement. The outputs from NORM, along with the outputs from RiskMod, are processed by the ToolKit model to assess the TPP.

A previous version of NORM, introduced in the WP-02 rate case, modeled only changes in expenses. This current version, essentially the same as the model used in the WP-07 Final Proposal, models both the accrual and cash impacts of the included risks, and supplies 3,000 games of both net revenue and cash impacts to the ToolKit.

2.5.1 Methodology

NORM follows BPA's traditional approach to modeling risks, which uses the *Monte Carlo* simulation methodology. In this technique, a model runs through a number of *games* or scenarios. In each game, each of the uncertainties is randomly assigned a value based on input specifications for that uncertainty. After all of the games have been run, the output data on the set of games can be analyzed and summarized in various ways, or passed to other tools.

2.5.2 Data Gathering and Development of Probability Distributions

To obtain the data used to develop the probability distributions used by NORM, BPA interviewed the subject matter experts (SMEs) for each capital and expense item modeled. Prior to each interview, the SMEs were sent a set of questions to think about regarding the risks surrounding the cost estimates included in the final PFR. During the interviews, the SMEs were asked for their assessment of the risks concerning their cost estimates, including the possible range of outcomes and the associated probabilities of occurrence. In some instances, the SMEs were able to provide a complete probability distribution. For the remaining cost items, BPA used the information provided to develop the probability distributions.

For the WP-07 Final Supplemental Proposal, BPA further revised the probability distributions to take into account actual results since the WP-07 Final Proposal. First, the uncertainty around FY 2007 actual costs and revenues was removed. Second, FY 2008 expenses were revised to be consistent with BPA's Third Quarter Review, and FY 2009 expenses were revised to be consistent with the Integrated Program Review (IPR). A more detailed description of the revisions for each cost and revenue item follows.

2.5.3 Inputs

2.5.3.1 CGS O&M

CGS O&M consists of the following four cost elements:

(1) base O&M;
(2) nuclear fuel;
(3) Decommissioning Trust Fund contributions; and
(4) NEIL insurance premiums.

For the Final Supplemental Proposal, NORM captured the uncertainty around the base O&M and NEIL insurance costs only. Energy Northwest (EN) has revised its O&M estimates for BPA's FY 2008-2009 since the Initial Supplemental Proposal. NORM has incorporated these revised estimates in the Final Supplemental Proposal. For base O&M, NORM assumes that the most likely outcome is the revised base O&M estimate from EN for each fiscal year. The new minimum values are the EN cost estimates from the Initial Supplemental Proposal. The new maximum values for the FY 2008-2009 probability distributions are derived from inflating the actual CGS O&M costs for FY 2006-2007. For FY 2008, the actual FY 2006 CGS O&M amount of $228.3 million was inflated by 6 percent to get a new maximum value of $242 million ($228.3 x 1.06 = $242). The revised FY 2008 estimate of $231.4 million was then subtracted from the new maximum value ($242 – $238.1 = $3.9). This difference, $3.9 million, was added to the revised FY 2008 Base O&M estimate of $215.9 million to get the new maximum base O&M value for FY 2008 ($215.9 + $3.9 = $219.8). The new maximum value for FY 2009 base O&M was calculated in a similar manner, except the FY 2007 actual value was used. Two years of actual data were used to better reflect the CGS two-year refueling cycle. For NEIL insurance, NORM modeled the uncertainty around the level of the gross premium and the level of earnings on the NEIL fund. Member utilities receive annual distributions based on the level of these earnings, which lowers the premiums they actually pay.

The distributions for CGS O&M are shown in Table 43 of the Documentation. Distributions are shown for each fiscal year for FY 2008-2009. *See* Documentation, WP-07-FS-BPA-12A.

2.5.3.2 Corps of Engineers (COE) and Bureau of Reclamation (Reclamation) O&M

For COE/Reclamation O&M, NORM models uncertainty around the following:

(1) additional security costs if an event occurs;

(2) additional fish costs if an event occurs;

(3) additional system needs;

(4) additional extraordinary maintenance; and

(5) base O&M.

For FY 2007, both COE and Reclamation under ran their budgets. Therefore, BPA developed new probability distributions around FY 2008-2009 base O&M expenditures. For FY 2008, the new minimum value equals the FY 2007 actual value inflated by 3 percent. Most likely values are the Third Quarter Review values for FY 2008, and IPR values for FY 2009. For Reclamation, new maximum values equal the most likely value plus $250 thousand for FY 2008 and the most likely value plus $500,000 for FY 2009. For COE, new maximum values equal the most likely value plus $500,000 for FY 2008 and the most likely value plus $1 million for FY 2009.

For additional security costs, NORM assumes a 5 percent probability that an event will occur that leads to a requirement for additional security at the COE and Reclamation facilities. The additional annual cost is the same for both the COE and Reclamation, at $3 million each.

Additional fish environmental costs are modeled similarly, with a 5 percent probability that an event will occur, requiring additional annual expenditures of $2 million each for both the COE and Reclamation.

For Additional System Needs, NORM models the uncertainty that additional repair and maintenance costs could be incurred above those contained in the Third Quarter Review for FY 2008 and the IPR for FY 2009 and the probability that an outage event will occur.

The distributions for Total COE and Reclamation O&M are shown in Table 44 of the Documentation. Distributions are shown for each fiscal year for FY 2008-2009. *See* Documentation, WP-07-FS-BPA-12A.

2.5.3.3 Colville/Spokane Settlement

In the Final Supplemental Proposal, NORM is using the current estimate of $20.5 million for the Colville settlement payment for FY 2008, which is based on FY 2007 actual results. For the Colville settlement payment for FY 2009, NORM models the uncertainty in the price per kWh paid and the variability in output from Grand Coulee. The payment to the Colville Tribe equals a base annual charge, which is calculated as a base annual price times the output from Grand Coulee. The base annual charge is subject to both a floor and a ceiling.

The base annual price equals the 1995 base price of 0.747153 mills/kWh, escalated by the BPA price escalator each year thereafter. The BPA price escalator equals the BPA power sales price for the previous fiscal year divided by the BPA power sales price for FY 1995 (27.14 mills/kWh). To estimate the BPA price escalator for the rate period, BPA compared estimates of the "average power sales price" for 2004 with the comparable estimates for 2006, 2007, and 2008. The "average power sales price" is computed by dividing revenues by MWh. The revenues included are firm power sales revenues (including Slice, regular PF, FPS and long-term sales, and non-wheeling transmission sales). The MWh are calculated from the categories of power sales used for computing the revenues (*i.e.,* no MWh are included for the non-wheeling transmission sales). To calculate non-wheeling transmission revenue, the 2004 figure of $503,067,879 was rounded to $500,000,000 and used for 2006, 2007, and 2008. The other figures were extracted from RiskMod databases.

The floor annual price is calculated as the FY 1995 floor price of 0.661414 mills/kWh escalated by the combined escalator for each fiscal year thereafter. Similarly, the ceiling annual price is the FY 1995 ceiling price (0.832892 mills/kWh) escalated by the combined escalator for each year thereafter. The combined escalator equals the simple average of the BPA price escalator and Consumer Price Index (CPI) escalator for the fiscal year. The CPI escalator is the ratio of the CPI for the September ending the previous fiscal year and the CPI for September 1995. To model the uncertainty around the CPI escalator for FY 2008-2009, NORM uses the discrete probability distributions contained in Table 52 of the documentation. *See* Documentation, WP-07-FS-BPA-12A.

To model the variability around Grand Coulee generation, the mean and standard deviation were calculated for the 50 historic water years average annual output. The mean and standard deviation were used as parameters for a normal probability distribution generated by @Risk, which was then truncated at the minimum and maximum values for the 50 historic years. The 50 years of data are provided in Table 54 of the documentation. *See* Documentation, WP-07-FS-BPA-12A.

Using the data described above, NORM calculates a base annual payment to the Colville Tribe, which equals the base annual price times the random draw for that year's output from Coulee. If the base payment exceeds the ceiling, the Colville payment equals the ceiling. If the base payment is below the floor, the payment is set equal to the floor, and the difference is carried forward as a loan to be paid off the following fiscal year. A new loan is created each year the base payment is below the floor or the following year's base payment is insufficient to pay off the previous year's loan.

Currently, legislation to establish a similar settlement with the Spokane Tribe has yet to pass the Congress. However, BPA believes there is at least a 60 percent probability that the legislation will pass during FY 2009. Therefore, NORM assumes that payments to the Spokane Tribe are 60 percent likely to occur for FY 2009. The payments equal 29 percent of the payments made to the Colville Tribe.

The distribution for the Colville Settlement payment for FY 2009 is shown in Table 45 of the documentation. A similar graph for the Spokane Settlement payment for FY 2009 is shown in Table 46 of the documentation. *See* Documentation, WP-07-FS-BPA-12A.

2.5.3.4 Public Residential Exchange

For the Final Supplemental Proposal, BPA is not modeling risk around residential exchange benefit levels for COUs. Three COU's notified BPA that they might wish to participate in the REP during FY 2009. As with the IOUs, the ASCs of the three COUs were forecast as part of the expedited ASC review process as described in Section 8 of the WPRDS, WP-07-FS-BPA-13. Based on this ASC forecast and the resulting PF Exchange rate, only one COU would receive REP benefits during FY 2009. Given the small magnitude of the COU REP benefits, approximately $1 million, and the fact that only one COU will be participating, BPA decided not to model this risk in NORM for the Final Supplemental Proposal.

2.5.3.5 Power Services Transmission Acquisition and Ancillary Services

For Transmission expense for the Final Supplemental Proposal, NORM is modeling uncertainty around third party General Transfer Agreement (GTA) wheeling and third party Transmission and Ancillary Services costs.

The uncertainty around Power Services' purchases of Transmission and Ancillary Services from Transmission Services is modeled in RiskMod.

For third-party GTA wheeling, NORM models the uncertainty around the level of future price increases for FY 2008-2009. For third-party Transmission and Ancillary Services, NORM models the uncertainty around additional costs due to congestion (either additional fees imposed or having to find an alternate, more expensive path). For Reserve and Other Services in the

WP-07 Final Proposal, NORM models the uncertainty around future Transmission Services price increases for FY 2008-2009. Because transmission rates for FY 2008-2009 were established in Transmission Services' recent rate case, NORM is no longer modeling this uncertainty for the Final Supplemental Proposal. The distributions for total Transmission Services Expense modeled in NORM are shown in Table 48 of the Documentation. Distributions are shown for each year for FY 2008-2009. *See* Documentation, WP-07-FS-BPA-12A.

2.5.3.6 Power Services Internal Operations

For this cost item, NORM models uncertainty around the following:

(1) Power Services System Operations;
(2) Power Services Scheduling;
(3) Power Services Marketing and Business Support; and
(4) Corporate G&A, including Shared Services and Transmission Services Supply chain allocated to Power Services.

For Corporate G&A, NORM assumes the Third Quarter Review value as most likely for FY 2008, and the IPR value as most likely for FY 2009, with a minimum value of 5 percent lower and a maximum value of 10 percent higher for both fiscal years.

To model uncertainty around the remaining cost items, NORM first summed the Third Quarter Review values as most likely for FY 2008, and summed the IPR values as most likely for FY 2009. A probability distribution was developed with a minimum that is 10 percent lower than the summed most likely values, and a maximum that is 10 percent higher.

The distributions for total Internal Operations Cost, including Corporate G&A that are modeled in NORM, are shown in Table 49 of the Documentation. Distributions are shown for each fiscal year for FY 2008-2009. *See* Documentation, WP-07-FS-BPA-12A.

2.5.3.7 Fish & Wildlife Expenses

For the Fish & Wildlife-related expenses, NORM models uncertainty around the following:

(1) Direct program costs; and

(2) U.S. F&WS Lower Snake River Hatcheries.

For FY 2008, NORM uses the values contained in the Third Quarter Review as final values, with no uncertainty assumed.

For FY 2009 direct program expenses, NORM assumes the IPR value as most likely. The minimum is assumed to be $5 million lower than the most likely value, and the maximum is assumed to be $21 million higher. The maximum increment of $21 million is the same as that used in the WP-07 Final Proposal. For FY 2009 U.S. F&WS Lower Snake River Hatcheries expense, NORM used the IPR value as the most likely, and used the same minimum and maximum values as the WP-07 Final Proposal.

A graph of the distribution for F&W Direct Program Expense for FY 2009, along with additional descriptive statistics, is shown in Table 50 of the Documentation. A similar graph for FY 2009 for the Lower Snake River Hatcheries expense is shown in Table 51. *See* Documentation, WP-07-FS-BPA-12A.

2.5.3.8 Capital Expenditures

For the Supplemental Proposal, NORM models uncertainty around the capital expenditures in the following areas:

(1) Conservation;
(2) Direct Program F&W;
(3) PS Capital Equipment (including Corporate allocated to PS);,
(4) COE/Reclamation Direct Funded Capital; and
(5) CGS Capital.

The uncertainty modeled relates to both the level of capital expenditures and the interest rate on the bonds or appropriations used to fund the investments.

2.5.3.9 Interest Rate and Inflation Risk

For interest rate risk, NORM modeled uncertainty around the following interest rates for new borrowings:

(1) 30-Year Appropriations;
(2) 30-Year U.S. Treasury Bonds;
(3) 5-Year U.S. Treasury Bonds;
(4) 13 to 15-Year Tax-Exempt Municipal Bonds; and
(5) 13 to 15-Year Taxable Municipal Bonds.

For inflation, NORM modeled the uncertainty around the Consumer Price Index (CPI). These were all modeled as discrete probability distributions.

During the customer workshop on NORM, customers commented that NORM lacked correlations between the distributions around interest rates and the inflation rate. BPA addressed this concern in the Final Proposal and is using the same approach for the Supplemental Proposal.

To address the correlations within a given fiscal year, a LOOKUP table was constructed containing 21 rows of potential interest rates and the corresponding rate of inflation for each year. Row 1 contains the minimum possible values, row 11 contains the median values, and row 21 contains the maximum possible values for each of the interest rates and the inflation rate for that year.

For FY 2008, each of the 21 rows has an equal probability of being selected. For each of the 3,000 games, NORM selects one of the 21 rows, thereby selecting the values in that row for that particular game. For example, if row 8 was chosen for FY 2008, the following interest rates and inflation rate would be used in that game.

- 30-Year Appropriations 4.81%
- 30-Year U.S. Treasury Bonds 5.71%
- 5-Year U.S. Treasury Bonds 4.66%
- 14-Year Tax-Exempt Municipal Bonds 4.17%
- 14-Year Taxable Municipal Bonds 5.62%
- Inflation Rate 1.62%

To address correlations between fiscal years, NORM sets the row number most likely to be chosen for the next fiscal year to be the same as the row number chosen in the current fiscal year. Continuing the example from above, where row 8 was chosen for FY 2008, the most likely row to be chosen in FY 2009 would again be row 8. Rows further removed from row 8 would become increasingly less likely to be chosen, with row 21 being the least likely row to be selected. The distributions for FY 2008-9 were updated for the Supplemental Proposal. The full distributions are in Table 52 of the Documentation. *See* Documentation, WP-07-FS-BPA-12A.

2.5.3.10 Federal Depreciation, Amortization, and Net Interest Distributions

Changes in the level of capital expenditures, the amount of plant put into service, and the interest rate on the debt that funded the capital change depreciation and amortization expense, and net interest expense. These in turn affect net revenues. The distributions for Total Federal depreciation, amortization, and net interest are shown in Table 53 of the Documentation. Distributions are shown for each fiscal year for FY 2008-2009. *See* Documentation, WP-07-FS-BPA-12A.

2.5.3.10.1 Conservation

To model uncertainty around the level of conservation capital expenditures for the Supplemental Proposal, NORM uses the Third Quarter Review value of $15 million for the FY 2008 most likely value of $32 million as the most likely value, with a minimum value of $7 million and a maximum value of $32 million. The new minimum value is based on FY 2007 actual expenditures of $6.955 million. For FY 2009, NORM uses the IPR value of $32 million, reduced by the 15% lapse factor, as the most likely value. The minimum value is $7 million, with a maximum of $40 million. Interest rate risk is based on the uncertainty around the five-year U.S. Treasury bond rate.

2.5.3.10.2 F&W Direct Program

For the Final Supplemental Proposal, NORM is not modeling risk around the level of F&W capital expenditures. For the last two years, the level of actual capital expenditures has been close to the total forecast spending amount. Interest rate risk is still being modeled for FY 2009, and is based on the uncertainty around the 30-Year U.S. Treasury Bond rate.

2.5.3.10.3 Power Services Capital Equipment

Capital equipment consists mostly of furniture and IT expenditures for PS and corporate staff. To model the uncertainty around the level of capital expenditures for the Supplemental Proposal, NORM uses the Third Quarter Review values for FY 2008 and the IPR values for FY 2009 as the most likely values for the probability distributions. The minimum values are 90 percent of the most likely values, and the maximum values are 1.1 times the most likely values. Interest rate risk is based on the uncertainty around the 30-Year U.S. Treasury Bond rate.

2.5.3.10.4 COE/Reclamation Direct Funded Capital

For the Final Supplemental Proposal, NORM is modeling the uncertainty around FY 2009 costs only.

For COE/Reclamation direct funded capital, NORM models uncertainty around:

- Level of annual expenditures;
- Level of plant-in-service; and
- Interest rate on 30-Year U.S. Treasury Bonds.

Unlike the other capital programs, not all COE and Reclamation investments are placed in service the same year the expenditure is made. Many projects take multiple years to complete, so the amount of plant put into service each year varies with the change in expenditure levels made over several years.

For the level of expenditures for FY 2009, NORM models uncertainty around the level of base investment and emergency capital needs. The incremental investment levels are then prorated to determine the incremental amounts of plant put into service during FY 2009.

2.5.3.10.5 Columbia River Fish Mitigation (CRFM)

The CRFM project is funded by appropriations received by the COE. The power portion of the investment becomes BPA's obligation to repay to the U.S. Treasury at the time the investment is placed into service in the accounting records. For the initial proposal, NORM modeled uncertainty around the amount of CRFM expenditures that will move into plant-in-service during the rate period and the associated interest rate. Three alternate scenarios were developed around levels of CRFM expenditures that would be placed in service during the rate period. NORM then assigned a probability to each of these scenarios. Subsequently, COE reviewed and updated its estimates of the amount of CRFM expenditures to be placed in service through FY 2009. With that update, the major source of uncertainty around this cost estimate was removed. Therefore, CRFM plant-in-service was not modeled in NORM in the WP-07 Final Proposal or this Final Supplemental Proposal. The interest rate risk associated with the plant-in-service amounts continues to be modeled in NORM for FY 2009, with the interest rate risk based on the uncertainty around the 30-Year Appropriations rate.

2.5.3.10.6 CGS Capital

In the initial WP-07 proposal, NORM modeled the uncertainty around the level of interest rates on the bonds used to fund CGS capital investments. For theWP-07 Final Proposal, NORM modeled the interest rate uncertainty, and whether the capital costs to replace the CGS condenser tubes would be incurred during FY 2009.

Since the WP-07 Final Proposal, EN has revised its estimates for CGS capital investments. The revised estimates include replacement of the CGS condenser tubes. These revised estimates have been included in NORM for the Final Supplemental Proposal. Also, BPA has already completed the FY 2008 financing for CGS capital expenditures. For these reasons, NORM is modeling for the Final Supplemental Proposal the uncertainty around interest rates only for CGS capital expenditures that affect BPA's FY 2009 expenses. The distribution for CGS Debt Service for FY 2009 is shown in Table 55 of the Documentation. *See* Documentation, WP-07-FS-BPA-12A.

2.5.3.11 Revenues from Generation Supplied Reactive (GSR)

For the WP-07 Final Proposal, NORM modeled the uncertainty around the level of payments that Power Services would receive for GSR services provided to Transmission Services for FY 2008 and FY 2009. Because Power Services is no longer receiving revenues from Transmission Services for within-the-band reactive power services, this uncertainty is not being modeled in NORM for the Final Supplemental Proposal.

2.5.3.12 Renewables Facilitation Costs

As a result of the PFR II process, BPA modeled in NORM the uncertainty around future levels of additional facilitation spending. For the Final Supplemental Proposal, NORM is modeling uncertainty around Renewables Facilitation costs for FY 2009 only. Little uncertainty remains around the level of expenditures for FY 2008. Due to the passage of renewable portfolio standards in Washington and Oregon, BPA reduced its expected level of expenditures significantly for FY 2009 during the IPR process. Therefore, NORM now assumes that the most likely value for FY 2009 will be the IPR value \$2.5 million, with a minimum of \$0 and a maximum of \$4.0 million. The distribution for Renewable Facilitation costs for FY 2009 is shown in Table 56 of the Documentation. WP-07-FS-BPA-12A.

2.5.3.13 Accrual to Cash (ATC) Adjustment

One of the inputs to the ToolKit (through NORM) is the ATC adjustment. NORM takes the deterministic values for the line items listed above and shown on Table 2 below and assigns to each a distribution. It then runs 3,000 games and feeds the results of these games into the ToolKit model. The ToolKit also accepts as input 3,000 net revenue scenarios from RiskMod. The 3,000 NORM-computed ATC adjustments make the necessary changes to convert these net revenue scenarios (accruals) into the equivalent reserves value (cash) needed by the ToolKit to calculate TPP.

Because not all changes in expense result in similar changes in cash, the ATC adjustment is being modeled probabilistically in NORM for the Final Supplemental Proposal. NORM uses the deterministic ATC Table (Table 2 in this section) as its starting point, but replaces the deterministic value with the new value for each game for the following line items in the table.

(1) Line 1: Depreciation/Amortization

(2) Line 4: Slice True-up included in All Other

Previously, NORM modeled uncertainty around the continuation of the debt optimization program. For the Final Supplemental Proposal, NORM is assuming a 100 percent probability that debt optimization will occur during FY 2008 and FY 2009.

Table 2
2007 Supplemental Proposal Accrual to Cash Adjustments
(dollars in millions)

		FY 2008	FY 2009
1	Depreciation/Amortization	$180.499	$188.764
2	Interest Adjustments	($45.937)	($45.937)
3	ENW Direct Pay Prepaid Expense	19.844	($51.408)
4	All Other (See Line 13 below)	($11.705)	($31.248)
5	**Cash provided by operating Activities**	**$142.701**	**$69.171**
6	Add: ENW Debt Service in Income Stmt.	$543.365	$545.539
7	Less: Current Estimated ENW Debt Service (PBL only)	(400.106)	(439.299)
8	Less: Planned Advanced Amortization of Federal Debt	(147.000)	(138.000)
9	**Total**	**($3.741)**	**($31.760)**
10	Less: Scheduled Federal Debt Amortization	($243.433)	($109.655)
11	Less: Revenue Financed Capital Investments	0.000	0.000
12	**PS TOOLKIT ATC INPUT**	**($104.473)**	**($ 81.244)**
13	**All Other** by major elements		
14	**TOTAL Line 4**	(11.705)	(31.248)
15	Slice & LB CRAC True-up	(23.907)	(7.814)
16	NB Revenue and other cash lags	23.504	0.000
17	Terminated contracts & Enron Settlement	0.436	0.436
18	PFIA & 3rd-Party Financing Advance Balances	(5.040)	(8.990)
10	Other	(6.698)	(14.880)

2.5.4 Output

The output of NORM is an Excel file containing: (1) the aggregate total expense deltas for all of the individual risks that are modeled; and (2) the associated ATC adjustment for each game. A typical run has 3,000 games. The ToolKit uses this file in its calculations of TPP.

3. RISK MITIGATION

3.1 Treasury Payment Probability (TPP)

One of BPA's policy objectives for this Supplemental Proposal is to meet its TPP standard. As described in Section 1 of this study, this standard for a one-year rate period is 97.5 percent for the risks, financial reserves, and tools attributed to Power Services.

The Treasury Payment Probability, or TPP, is the probability that a BPA (or a business line or business function) will have sufficient financial reserves to cover all of the financial obligations to the Treasury that have been assigned to it during the course of a rate period, given the risks identified in the risk analysis and the available risk mitigation tools. BPA's 10-Year Financial Plan, adopted in 1993 and revised July 31, 2008, calls for BPA to set rates to achieve a 95 percent TPP in each two-year rate period. Since FY 2002, the transmission and generation functions have set their rates separately, and BPA has determined that if each function separately meets the TPP standard with its respective rates and the reserves attributed to that business line, the Agency TPP requirement will be met. BPA has calculated that a 97.5 percent TPP for a one-year rate period is equivalent to the two-year 95 percent TPP called for in the 10-Year Financial Plan, *see* Section 1.1.2, above.

3.2 ToolKit Overview

The ToolKit is an Excel 2003® spreadsheet that BPA uses to evaluate the adequacy of its Power rates to meet the TPP standard, given the net revenue variability embodied in the distributions of operating and non-operating risks. Many of the settings are entered on the ToolKit main page (the main worksheet). It reads in data from two external files, one each from RiskMod and NORM. Most of the logic for simulating the financial results in the years included in a ToolKit analysis is in VBA code (Microsoft's *V*isual *B*asic for *A*pplications). This code contains comments that document how the code works, and is a useful reference for understanding how the ToolKit works.

More specifically, the ToolKit is used to assess the effects of various policies, assumptions, changes in data, and risk mitigation measures on the level of year-end reserves attributable to generation. It registers a deferral of a Treasury payment when these reserves fall below the level of "Liquidity Reserves" entered on the main page of the ToolKit. BPA has determined that the amount of liquidity that has to be supplied by financial reserves is $50 million. The ToolKit is run for 3,000 "games" or scenarios. TPP is calculated by dividing the number of those games where the ending FY 2009 reserve level is at least $50 million by 3,000.

Most of the modeling of risks is performed by RiskMod and NORM, documented in Section 2 of this study. The ToolKit reads in distributions of values from files created by RiskMod and NORM and calculates the TPP, other risk statistics and reports results, and allows analysts to calculate how much PNRR is needed, if any, and how large a CRAC is needed, if any, to meet the TPP standard.

3.3 Tools Incorporated into the Supplemental Proposal

The preceding sections of this study described the risks that BPA is modeling explicitly. This section describes the tools for mitigating those risks that BPA has considered. Some of these tools are modeled and included in BPA's rate proposal. Others are not modeled – specifically, the NFB Adjustment and the Emergency NFB Surcharge – but are included as part of BPA's risk mitigation package. The following sections describe each of these risk mitigation tools.

3.3.1 Tools Modeled in the ToolKit

3.3.1.1 Reserves Available for Risk and PNRR

Reserves Available for Risk. The fundamental protection against the financial impacts of the uncertainty BPA faces is its financial reserves. For this rate proposal, it is the reserves available for risk attributed to the generation function (Power Services reserves) that are considered when measuring TPP. Financial reserves available to the generation function comprise cash and investments held by the U.S. Treasury in the Bonneville Fund, plus amounts of deferred borrowing. Deferred borrowing refers to amounts of capital expenditures that BPA has made that authorize borrowing from the Treasury when BPA has not yet completed the borrowing. Deferred borrowing amounts are converted to cash when the borrowing is completed.

Some reserves attributed to Power are not considered to be available for risk. In this Supplemental Proposal, BPA considers that reserves that have been generated since May 2007 by the cessation of REP payments to regional IOUs are not available for risk. These funds are expected to be completely distributed by a combination of REP payments to IOUs and refunds (in the form of rate credits) to COUs.

Power reserves mitigate financial risk by serving as a source of cash for meeting financial obligations during years in which net revenue and the corresponding cash flows are lower than anticipated. In years of above-expected net revenue and cash flow, financial reserves can be replenished in order to be available in later years.

PNRR. BPA conducts analyses of its TPP using current projections of Power Services reserves in its rate cases. If the TPP is below the standard established in the 10-Year Financial Plan, as translated for the number of years in the rate period, then the projected reserves, along with whatever other risk mitigations are considered in the analysis, are not sufficient to reach the TPP standard. This is typically corrected by adding PNRR to the revenue requirement as a cost needed to be recovered by rates. This has the effect of increasing rates, which will increase the net cash flow, which will increase the available Power Services reserves, and therefore increase TPP.

Compared to most of the expenses in the revenue requirement, PNRR is an unusual cost. For one thing, there is no parallel expectation that cash is disbursed. For example, if BPA were able to find financial instruments in the market for mitigating its hydro and market risk, it would have to pay fees to counterparties in one way or another that it would not get back – there would be a long-term net cost. For another, including PNRR in one rate case is likely to reduce the need for PNRR or other forms of risk mitigation in subsequent rate cases. If it turns out that the reserves generated by the rate increase PNRR causes are not drawn down to pay bills in the rate period under consideration, they remain available in later rate periods and will serve to reduce the cost of risk mitigation that customers will pay then, all else being equal.

3.3.2 Other Agency Reserves Temporarily Available to Power

The WP-07 Final Proposal described a temporary availability to the generation function of reserves attributed to the Transmission function in excess of the reserves needed to support the Transmission function's TPP. This applied to FY 2007 only, and any use by Power Services of these reserves was required to be reversed during FY 2008. This amount was calculated in the TBL 2006 rate case (TR-06); no similar amount was determined from TBL or Transmission Services rate cases for other years to be temporarily available to Power Services. In addition, the one-year TPP period, FY 2009, does not allow for the use of reserves in one year and the reversing of the usage in a later year within the same TPP period. Therefore, no such temporary availability of reserves has been assumed for FY 2009.

3.3.3 The Cost Recovery Adjustment Clause (CRAC)

Cost recovery adjustment clauses, or CRACs, can be very powerful risk mitigation tools. BPA proposed a single CRAC in its WP-02 Final Proposal. The WP-02 Supplemental Final Proposal, a result of highly effective collaboration between BPA and its power customers, included three distinct CRACs: (1) the Load-Based (LB) CRAC dealt with the financial uncertainty of the augmentation solution; (2) the Financial-Based (FB) CRAC mitigated general financial risks; and (3) the Safety Net (SN) CRAC served as a back-stop against financial risks that could not be handled by the first two CRACs. In the WP-07 Final Proposal, BPA returned to a single CRAC.

BPA has employed CRACs or Interim Rate Adjustments (IRAs) as rate adjustment mechanisms that respond to the financial risks BPA faces. Financial reserves were the original metric used for determining whether this mechanism had triggered. BPA decided in the WP-02 Final Proposal to use accumulated net revenues because net revenues are a more standard financial metric. With this Supplemental Proposal, BPA continues this practice.

Table 3
CRAC Annual Thresholds and Caps
(dollars in millions)

AMNR Calculated at end of Fiscal Year	CRAC Applied to Fiscal Year	CRAC Threshold in AMNR	Approx. Threshold as Measured in PS Reserves	Maximum CRAC Recovery Amount (CRAC Cap)
2008	2009	–$29.3	$750	$36

3.3.3.1 Basic Description of the CRAC

The CRAC for FY 2009 is very similar to the CRAC from the WP-07 Final Proposal. It is an annual upward adjustment in energy and demand charges for rates subject to the CRAC. The CRAC has a limit to the annual collection amount of $36 million. The threshold is an amount of Power AMNR as accumulated since the end of FY 1999. The AMNR threshold values are calibrated to be equivalent to Power financial reserve levels of $750 million.

The CRAC (and NFB Adjustment and DDC) calculations for FY 2009 will be made shortly before the beginning of FY 2009. A forecast of the year-end AMNR will be made after the FY 2008 3rd Quarter Review and then compared to the thresholds for the CRAC and the DDC. If this AMNR forecast is below the CRAC threshold, an upward rate adjustment will be calculated for the duration of FY 2009. If the forecast is above the threshold for the DDC, a downward rate adjustment is calculated to distribute dividends to applicable rates for the duration of FY 2009.

3.3.3.2 Differences from the FB CRAC

The differences between the WP-07 Final Proposal CRAC and the WP-02 FB CRAC are described in the WP-07 Final Proposal. The proposed CRAC for this Supplemental Proposal is the same as the current (*i.e.*, WP-07 Final Proposal) CRAC except that the AMNR threshold has been recalculated and the Cap has been correspondingly reduced from $300 million to $36 million.

3.3.3.3 Differences from the SN CRAC

The differences between the WP-07 Final Proposal CRAC and the WP-02 SN CRAC are described in the WP-07 Final Proposal.

3.3.3.4 New CRAC Features

Changes from the WP-02 CRAC methodology to the WP-07 Final Proposal CRAC methodology are described in the WP-07 Final Proposal.

3.3.3.4.1 Administrator's Discretion to Adjust the CRAC

BPA is including in the CRAC methodology a process that allows the Administrator, late in FY 2008, to look ahead to FY 2009 and determine whether any or all of the CRAC amount calculated by the GRSP formula for FY 2009 is needed to help BPA maintain its financial standing. The ability to apply discretion in the CRAC percentage adjustment is tempered by the requirement to maintain the one-year TPP standard of 97.5 percent. This requirement protects the TPP from departing from the stated objective, but provides for lower rates if BPA does not project that it will need the additional revenues to maintain an adequate TPP.

3.3.3.4.2 One-Time Recalculation of the CRAC and DDC Thresholds

The one-time recalculation of the CRAC and DDC thresholds that was included in the WP-07 Final Proposal is not proposed in the Supplemental Proposal because the total participation in the Flexible PF Rate Program has been determined.

Table 4: Not Used

Table 5: Not Used

3.3.3.4.3 Contingent Mechanism for Additional Liquidity

BPA is not proposing that the supplemental FY 2009 rates will include a contingent mechanism for additional liquidity. BPA set the liquidity reserve level to $50 million in the contingent process following completion of the WP-07 Final Proposal, and that is as low a level as BPA believes is prudent.

3.3.4 Dividend Distribution Clause (DDC)

One of the financial policy objectives for this Supplemental Proposal was to ensure that Power Services reserves do not accumulate to excessive levels. A mechanism used in the WP-02 Final

Proposal to guard against this possibility was the DDC. The DDC is triggered if AMNR is above (instead of below as with the CRAC) a threshold, and if so, there is a downward adjustment to rates. In the same way that a CRAC passes bad financial outcomes to BPA's customers, a DDC passes good financial outcomes to BPA's customers.

Table 6
DDC Thresholds
(dollars in millions)

AMNR Calculated at end of Fiscal Year	DDC Applied to Fiscal Year	DDC Threshold in AMNR	Approx. Threshold as Measured in PS Reserves
2008	2009	$270.7	$1,050

3.3.4.1 Differences from the Current DDC

The proposed DDC is the same as the current (*i.e.*, WP-07 Final Proposal) DDC except that the AMNR threshold has been recalculated.

3.4 Tools Not Modeled in the ToolKit

3.4.1 NFB Adjustment and Emergency NFB Surcharge

Being certain it can cover its fish and wildlife costs is an extremely important objective for BPA. Because of uncertainty over some of BPA's fish and wildlife obligations, due in part to litigation, it is difficult to determine the associated costs to include in the rates for FY 2009. In the WP-02 Final Proposal, the uncertainty over the financial impacts of future fish measures was reflected by a set of 13 distinct alternatives for fish and wildlife. No such set of alternatives exists for FY 2009. Today, BPA faces uncertainty about potential court-ordered measures to address Endangered Species Act-listed fish. Because the uncertainty is open-ended, BPA believes it is necessary to have an open-ended adjustment mechanism to ensure that BPA can fund its fish and wildlife obligations despite the uncertainty.

This Supplemental Proposal includes two related features that help to mitigate the financial risk to BPA and its stakeholders that is caused by uncertainty over future fish and wildlife obligations and their financial impacts. Both of these features are continuations of features in the WP-07 Final Proposal. They are both designated "NFB" for NMFS FCRPS BiOp, or more fully, the ***N***ational Marine Fisheries Service ***F***ederal Columbia River Power System ***B***iological Opinion.

An NFB Trigger Event is one of the following four kinds of events that results in changes to BPA's obligations compared to those in the WP-07 Final Supplemental Proposal as modified prior to this Trigger Event:

(1) A court order in *National Wildlife Federation vs. National Marine Fisheries Service*, CV 01-640-RE, or any other case filed regarding a NMFS-issued FCRPS BiOp, or any appeal thereof ("Litigation");

(2) An agreement (whether or not approved by the Court) that results in the resolution of issues in, or the withdrawal of parties from, the Litigation;

(3) A new NMFS FCRPS BiOp; or

(4) A BPA commitment to implement Recovery Plans under the ESA that results in the resolution of issues in, or the withdrawal of parties from, the Litigation.

The NFB Adjustment responds to NFB Trigger Events that occur in FY 2008 and decrease BPA's FY 2008 net revenue; it can adjust the cap of the CRAC that applies to certain rates in FY 2009. The Emergency NFB Surcharge responds to NFB Trigger Events that occur in FY 2009 and decrease BPA's FY 2009 net revenues; it can trigger rate surcharges during FY 2009 if BPA is experiencing a significant cash crunch during FY 2009.

As currently defined, NFB Trigger Events do not include court orders, agreements or BiOps that are not related to the litigation referenced above. If needed, BPA will reexamine the NFB

Adjustment and Emergency NFB Surcharge, including the definition of NFB Trigger Events, in its next rate case.

3.4.1.1 NFB Adjustment

The NFB Adjustment protects the financial viability of BPA and its financial resources from the potential for a large impact from litigation-related changes in the operation of the FCRPS and in related fish and wildlife costs. The NFB Adjustment results in an upward adjustment to the CRAC Cap for FY 2009 if additional fish and wildlife costs in FY 2008 arise from one or more NFB Trigger Events.

While the NFB Adjustment increases the *Cap* on the amount the CRAC can collect, it does not necessarily increase the *amount of revenue* collected. If the NFB Adjustment triggers but AMNR is above the CRAC threshold, there will be no adjustment to rates because BPA's financial reserves were able to cover the increased costs. On the other hand, if AMNR is below the threshold, the NFB Adjustment will allow BPA to recover more than the $36 million CRAC Cap if such amounts are needed.

There can be multiple triggering events in any year that are included in the analysis of financial impacts even though there is only one final analysis per year of the total financial impacts due to triggering events that will adjust rates. For example, there could be more than one NFB Trigger Event in FY 2008 that alters the financial impacts of operations in FY 2008, such as issuance of a final BiOp, and a court order regarding that BiOp. Both of these triggering events would be included in the calculation of the single NFB Adjustment that would increase the Cap on the CRAC collection during FY 2009. There can be only one NFB Adjustment in any year.

Each NFB Adjustment affects only one year. However, since the comparison used to calculate the NFB Adjustment is the actual costs and operations for fish against the costs and operations assumed in the rate case, as modified prior to a Trigger Event, it is possible for a Trigger Event to affect operations in more than one year. For example, a decision in FY 2008 may affect operations in both FY 2008 and FY 2009. The analysis of the total financial impact during FY 2008 for adjusting the Cap on the CRAC applying to FY 2009 would be separate from the analysis of the total financial impact during FY 2009 for considering a possible Emergency NFB Surcharge for application to FY 2009 rates or for adjusting the Cap on the CRAC applying to FY 2010 (if the Power rates for FY 2010 include the NFB adjustment), depending on whether there is a cash crunch in FY 2009. NFB Trigger Events during FY 2009 are not covered by the NFB Adjustment in this rate proposal *per se* because the effect of incorporating those increases would need to be collected during FY 2010, and the rates for FY 2010 are not addressed in this rate proceeding. BPA will consider extending the NFB Adjustment to the rates for FY 2010-2011 in the WP-10 rate proceeding.

As a result of the Partial Resolution of Issues adopted in the WP-07 Final Proposal, BPA and parties agreed that the revenues above $300 million resulting from the NFB Adjustment to the Cap should be collected over a different revenue basis than the CRAC. In this WP-07 Final Supplemental Proposal, BPA continues this distinction, though the CRAC cap is now $36 million, and therefore $36 million is the amount at which the revenue basis will be changed. The CRAC revenue basis (before the NFB Adjustment Calculation) is applied to LLH and HLH energy and Load Variance sales. If an NFB Adjustment increases the CRAC cap, and if the CRAC triggers for more than $36 million, the CRAC amounts above $36 million will be collected from LLH and HLH energy, Load Variance, and Demand sales proportionally under the firm power rate schedules subject to the CRAC. As a result, revenue recoverable for the financial impacts of the NFB Adjustment is spread over a larger basis than the CRAC, thus lowering the percentage adjustment to the rates. This difference produces a complexity in the CRAC adjustment in that it could require two percentages to be calculated.

3.4.1.2 Emergency NFB Surcharge

The Emergency NFB Surcharge was created as a second way to respond to the financial impacts of NFB Trigger Events when those impacts occur during a time when BPA's financial reserves are perilously low. In such circumstances, waiting for the NFB Adjustment to generate additional revenues in the subsequent year could leave BPA at great financial risk. If BPA determines that the probability of making all of its payments to the U.S. Treasury during the fiscal year in which an NFB Trigger Event occurs which reduces net revenue by at least $10 million is less than 80 percent, the Emergency NFB Surcharge will go into effect, leading to upward rate adjustments during the same year as the NFB Trigger Event, generating additional revenue before the end of the year.

3.4.2 Ability to Begin New 7(i) Proceeding

Because the WP-07 Final Supplemental Proposal applies to a single year, FY 2009, BPA will not have the ability to begin a new 7(i) proceeding partway through this rate period.

3.4.3 Liquidity Tools

During the WP-07 rate proceeding, BPA and customers worked on a number of liquidity tools. BPA is not including any additional liquidity tools in the Supplemental Proposal.

3.4.3.1 Direct Pay of Energy Northwest Budget

Many of BPA's public customers were participating in the Energy Northwest (EN) net billing agreements until FY 2006. These agreements were developed as a way to enter into long-term agreements that were not subject to annual appropriations before BPA could acquire resources.

The net billing agreements directed customers to remit their payments for BPA power deliveries to EN rather than to BPA until EN's receipts covered its annual budget, a concept referred to as "net billing" because the customers received monetary credits to their power bills from BPA. The net billing period started with the bills for May power deliveries, and ensured that EN would have the money it needed at the beginning of its fiscal year in July. This arrangement resulted in EN's receiving more cash than it needed early in its fiscal year. This surplus was often as large as several hundred million dollars by September 30, leaving BPA relatively low on cash when it needed to make its year-end payment to the Treasury.

In 2006 BPA completed negotiations with EN and began to fund EN through the "direct pay" arrangement under which BPA would send to EN each month an amount of money sufficient to fund EN for that month. The Net Billing agreements were still in effect, but since these agreements provided a way for EN to receive whatever funding it had not otherwise received – and it was receiving the funding it needed through Direct Pay – there were no actual Net Billing transactions after the adoption of Direct Pay. This eliminated the annual creation of the surplus just mentioned, and effectively increased the amount of cash available to BPA at the end of each of its fiscal years for ensuring its payment to the Treasury.

BPA incorporated the ability to directly pay EN obligations into the calculation of rates in the WP-07 Final Proposal, and has incorporated Direct Pay into the Supplemental Proposal also.

3.4.3.2 Flexible PF Rate Program

BPA has adopted the Flexible PF Rate Program, developed by customers and BPA as part of an ongoing endeavor to identify additional sources of liquidity. The Flexible PF Rate Program is a means by which BPA may increase the amount payable by participating customers for power service in a given month and thereafter reduce the amount payable for power service from such customers in subsequent months. The program is intended to increase BPA's liquidity by shaping power revenues to cover extraordinary cash flow requirements. BPA has offered the Flexible PF Rate Program to non-Slice purchases under the Flexible PF Rate Option.

3.4.3.3 Additional Liquidity Tools

BPA is not proposing to include any new liquidity tools in the FY 2009 rate package or to make provisions to modify the FY 2009 rates if any additional tools become available; such tools would be incorporated into rates at the first opportunity.

3.4.3.4 The Net Impact on the Liquidity Reserve Level

Both Direct Pay and the Flexible PF Rate Program affected the liquidity reserve level for reserves available for risk for the Power function, and they were incorporated into the WP-07 Final Proposal in two different ways. The change to Direct Pay was completed by the time the Final Proposal was completed, so the cash flow and liquidity effects were incorporated into the Final Proposal. Participation in the Flexible PF Rate Program, on the other hand, was not completed until after the Final Proposal, so the GRSPs included a provision for lowering the CRAC threshold if additional participation was secured (and it was). Therefore, after the Final Proposal was completed, and the additional participation was verified, the CRAC threshold was reduced from an AMNR level equivalent to $750 million to an AMNR level equivalent to $641 million. Since the participation in that program is known now, BPA is proposing a CRAC threshold at the AMNR equivalent of $750 million again.

3.5 ToolKit Modification/Changes in TPP Modeling

Rates set in the WP-07 Final Proposal were different from those in the period covered by the SN-03 rate case (the SN CRAC rate case) for several reasons detailed in the WP-07 Risk Analysis Study, *See* Risk Analysis Study, WP-07-FS-BPA-04, at 47. These changes are continued in the Supplemental Proposal. A few changes from the WP-07 Final Proposal are being made in the Supplemental Proposal and are described in following sections.

3.5.1 End of FB CRAC, SN CRAC, and LB CRAC

The Supplemental Proposal continues the one-CRAC approach that was adopted in the WP-07 Final Proposal.

3.5.2 Credit for Operating and Regulating Reserves

Following the publication of the WP-07 Initial Proposal, the parties negotiated a Partial Resolution of Issues, *see* WP-07-E-BPA-49, Appendix 1, which included removal of the credit for Operating and Regulating Reserves. Therefore, this credit is no longer applicable and was removed from ToolKit for this Supplemental Proposal.

3.5.3 Incorporating the IOU REP Settlement Benefits

One of the most significant developments in the WP-07 Final Proposal, as measured by the number of adjustments that had to be made since the SN-03 Final Proposal, was the IOU REP settlements. The REP Settlement Agreements were overturned by the Ninth Circuit, and now BPA will provide REP benefits to the IOUs through an REP in FY 2009. Under the REP for FY 2009, there will not be an interaction between PNRR, a CRAC or a DDC, and the benefits for the IOUs, so the logic in the ToolKit has been simplified. If a CRAC (or DDC) is triggered for the FY 2009 rates according to calculations made in September 2008, an amount of money to be collected (or distributed) will be determined. Then an increase (or decrease) in the PF rate and a corresponding increase (or decrease) in the PF Exchange rate will be calculated that would collect (or distribute) that amount through increased (or decreased) PF revenues and decreased (or increased) residential exchange payments.

3.5.3.1 PNRR

BPA is not proposing to include any PNRR in the revenue requirement for the Supplemental Proposal because starting reserves available for risk and the CRAC are sufficient to meet the TPP standard for a one-year rate period.

3.5.3.2 Updates to the Forward-Block Market Price

The FY 2009 REP benefits do not use a forward-block market price.

3.5.3.3 CRAC Impacts

The ToolKit does not need to model interactions between the CRAC and the IOU REP benefits to calculate TPP.

3.5.3.3.1 Computing Post-CRAC PF Rate if IOU REP Settlement Benefits Can Change

This issue is moot.

3.5.3.3.2 The ToolKit Calculations Including Effect of Cap and Floor

There are no more REP Settlement Caps and Floors; this issue is moot.

3.5.3.4 DDC Impacts

The ToolKit does not need to model interactions between the DDC and the IOU REP benefits to calculate TPP.

3.5.4 U.S. Treasury Deferral Modeling

The Supplemental Proposal uses the same modeling of Treasury Deferrals used in the WP-07 Final Proposal.

3.5.5 New Outputs

No new outputs have been added to the ToolKit since the WP-07 Final Proposal. Some existing outputs have been disabled or are no longer working.

3.5.5.1 Graphs

The rate variability graph no longer functions because details of how the REP will function were finalized too late to incorporate into the version of the ToolKit used in the Supplemental Proposal.

3.5.5.2 IOU REP Settlement Benefits Output

The "IOU_Adj" sheet no longer works because details of how the REP will function were finalized too late to incorporate into the version of the ToolKit used in the Supplemental Proposal.

3.6 ToolKit Inputs and Assumptions

3.6.1 Inputs and Assumptions on the ToolKit Main Page

3.6.1.1 Risk Analysis Model (RiskMod)

3,000 RiskMod runs were made to develop distributions for FY 2008-2009. The TPP is measured only for FY 2009, but the starting reserves available for risk for FY 2009 depend on events yet to unfold in FY 2008; these runs reflect that FY 2008 uncertainty.

3.6.1.2 Non-Operating Risk Model (NORM)

A NORM distribution was created for the FY 2008-2009 period that reflects the uncertainty around non-operating expenses, as described earlier in this study. *See* FY 2009 Risk Analysis Study Documentation, WP-07-FS-BPA-12A.

3.6.1.3 Starting Reserves Available for Risk

The 3,000 values for starting FY 2009 reserves available for risk values have an expected value of $854.8 million. This results from a starting FY 2008 known value of $952.1 million and the simulation of the remainder of FY 2008.

The reserves attributed to Power Services at the beginning of FY 2008 were $1,093.4 million. Of this amount, $141.3 million is due to funds collected in revenues for distribution as REP benefits to IOUs, but not paid out. These funds are not considered to be available for risk. Therefore, the starting reserves available for risk are $1,093.1 million - $141.3 million = $952.1 million.

3.6.1.4 Starting AMNR

The 3,000 FY 2009 starting AMNR values have an expected value of -$75.5 million. This results from a starting FY 2008 known value of $69.0 million and the simulation of the remainder of FY 2008.

3.6.1.5 Treatment of U.S. Treasury Deferrals

U.S. Treasury deferrals are treated using the "Hybrid" logic described in Section 3.5.4.

3.6.1.6 Other Agency Reserves Temporarily Available

This input is not used. *See* Section 3.3.2 above.

3.6.1.7 Interest Rate Earned on Reserves

Interest earned on reserves available for risk attributed to Power Services is calculated at the rate of 5.46 percent per year.

3.6.1.8 Interest Credit Assumed in the Net Revenues

A basic feature of the ToolKit is that the interest earned on reserves which is included in the revenue requirement is deterministic; that is, it does not take into account the variation in reserves levels from one game to another. To capture the interest effects of this variability, the revenue requirement assumptions about interest earned on reserves is backed out of all ToolKit games and replaced with game-specific calculations of interest credit. The revenue requirement amounts that are backed out are $58.1 million and $57.9 million for FY 2008 and FY 2009, respectively.

3.6.1.9 The Cash Timing Adjustment

The cash timing adjustment reflects the interest credit impact of the typical shape of Power Services' reserves throughout a fiscal year. The ToolKit calculates interest earned on reserves by making the simplifying assumption that reserves change linearly from the beginning of the year to the end. It takes the average of the starting reserves and the ending reserves and multiplies that figure by the interest rate for that year. Because Power Services' cash payments to the Treasury are not evenly spread throughout the year, but instead are heavier in September, Power Services will typically earn more interest in BPA's monthly calculations than the straight-line method yields. The cash timing adjustment is a number from the repayment study that approximates this additional interest credit earned on reserves throughout the fiscal year. The cash timing adjustments for this proposal are $7.1 million and $7.4 million for FY 2008 and FY 2009, respectively.

3.6.1.10 Other Cash Adjustments

There are no adjustments of this type.

3.6.2 Inputs on the ToolKit "IOU_Data" Sheet

3.6.2.1 Flat-Block Forward Market Prices

These values are no longer used.

3.6.2.2 PF Rates (Before ToolKit Adjustments)

Several rate outputs from the RAM were passed to the ToolKit in the WP-07 Final Proposal. These values are not used in the Supplemental Proposal.

3.6.2.3 Pre-ToolKit IOU REP Settlement Benefits

As there is no longer an IOU REP Settlement, these values are not used.

3.6.2.4 Flat PNRR Rate Impact & PNRR Shape

The "Flat PNRR Rate Impact" assumption was made in ToolKit to match the rate-making logic used in the WP-07 Final Proposal for determining the value of the IOU REP Settlement Benefits. This settlement no longer exists; there is no longer a need for a flat PNRR shape, and this cell is irrelevant.

3.7 ToolKit Output

The TPP for the one-year FY 2009 period is 99.2 percent. The expected value of CRAC revenue is $0 million, and the expected value of DDC payments is $0 million. The expected value of reserves available for risk attributed to Power is $855 million for the end of FY 2008 and $769 million for the end of FY 2009. *See* Documentation, WP-07-FS-BPA-12A.