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

2010 BPA Rate Case
Wholesale Power Rate Final Proposal

RISK ANALYSIS AND MITIGATION STUDY

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WP-10-FS-BPA-04

BONNEVILLE POWER ADMINISTRATION

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RISK ANALYSIS AND MITIGATION STUDY

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COMMONLY USED ACRONYMS

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

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

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

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

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

1. INTRODUCTION

BPA's environment is filled with numerous uncertainties, and thus the ratesetting process must take into account a wide spectrum of risks. The objective of the risk analysis is to identify, model, and analyze the impacts that key risks and risk mitigation tools have on Power Services (PS) net revenue (total revenues less total expenses). This is carried out in two distinct steps: a risk analysis step, in which the distributions, or profiles, of operating and non-operating risks are defined, and a risk mitigation step, in which different risk mitigation tools are tested to assess their ability to recover power costs in the face of this uncertainty.

1.1 BPA's Treasury Payment Probability (TPP) Standard

In the WP-93 rate proceeding, BPA adopted and implemented its 10-Year Financial Plan, which included a policy requiring that BPA set rates to achieve a high probability of meeting its payment obligations to the U.S. Treasury (Treasury). 1993 Final Rate Proposal Administrator's Record of Decision (ROD), WP-93-A-02, at 72. The specific standard set in the 10-Year Financial Plan was a 95 percent probability of making both of the annual Treasury payments in the two-year rate period on time and in full. This TPP standard was established as a rate period standard; that is, it focuses upon the probability that BPA can successfully make all of its payments to Treasury over the entire rate period, rather than setting numerical goals for year-to-year performance. The 10-Year Financial Plan was updated July 31, 2008, and remains in effect. The original 10-Year Financial Plan is available at http://www.bpa.gov/corporate/Finance/financial%5Fplan/10-year_BPA_Financial_Plan.pdf; the 2008 updated Financial Plan is available at http://www.bpa.gov/corporate/Finance/financial_plan/BPA_Financial_Plan.pdf.

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 financial reserves are insufficient to pay all bills on time. TPP is therefore a prospective measure of BPA's overall ability to meet its financial obligations.

1.2 Risk Mitigation Objectives

BPA's policy objectives for the risk mitigation package include the following five objectives:

1) A rate design that meets BPA's financial standards, including meeting the 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; and
5) Reserve levels that are not built up to unnecessarily high levels.

It is important to understand that these objectives are interdependent, which requires BPA to balance these competing objectives when developing its overall rate design strategy.

1.3 Overview of the Risk Analysis

Two statistical models are used in the risk analysis step for this rate proposal, the Risk Analysis Model (RiskMod) and the Non-Operating Risk Model (NORM). A third model, the ToolKit, is used to test the effectiveness of risk mitigation tools in the risk mitigation step. RiskMod is discussed in section 2; NORM is discussed in section 3; and the ToolKit is discussed in section 4. The models function together so that BPA can develop rates that cover all of its costs and provide a high probability of making its Treasury payments on time and in full during the rate period.

Among the uncertainties that PS must mitigate, the most financial variability is associated with hydro conditions, market prices, and river operations for fish recovery, which affect BPA's net secondary revenues. Most of the power marketed by BPA is hydro-based, and annual generation is a direct function of precipitation in the Columbia River basin. As a result, BPA has little control over the amount of available generation from year to year. Wholesale market price variability, which is primarily driven by natural gas price variability, also significantly impacts the variability in BPA's net secondary revenues from year to year. Accordingly, achieving the particular level of net secondary revenues that is assumed in setting base power rates is uncertain. These uncertainties are discussed in section 2 and in the Risk Analysis and Mitigation Study Documentation (Documentation), WP-10-BPA-FS-04A, section 2.4.

Further uncertainty for BPA's net secondary revenues arises from the financial impacts of potential changes in river operations for fish mitigation. As a result of ongoing litigation over the Federal Columbia River Power System (FCRPS) Biological Opinions (BiOps), a new BiOp may be adopted or changes in river operations or fish and wildlife measures may be required that could reduce BPA's actual net secondary revenues compared to the estimates on which power rates are based.

1.4 Overview of Risk Mitigation

Financial reserves are BPA's primary tool for managing the financial risk PS faces. Given the large magnitude of the financial risk, if BPA were to rely solely on augmenting insufficient financial reserves with Planned Net Revenues for Risk (PNRR) for risk mitigation, power rates would need to include a large risk premium to meet BPA's TPP standard. This Study documents the risk mitigation package included in the final power rates. This package, rather than relying solely on high, fixed PNRR, balances PNRR with variable rate mechanisms by relying on the Cost Recovery Adjustment Clause (CRAC) and Dividend Distribution Clause (DDC) to work with PNRR to achieve the TPP policy objective of 95 percent. This balance makes the risk mitigation package less expensive on an expected value basis, because the rates can be adjusted annually to respond to uncertain financial outcomes, and additional revenues would be collected only when financial conditions require them. *See* section 1.3 for discussion of the policy objectives considered when developing this risk package.

The following items are included in the calculation of TPP.

1) *Starting PS Reserves Available for Risk.* Financial reserves include cash in the BPA Fund and the deferred borrowing balance. Reserves available for risk attributed to Power were $874.9 million at the beginning of FY 2009.

2) *Planned Net Revenues for Risk.* PNRR is the final component of the revenue requirement that is added to annual expenses. PNRR is needed only when the risk mitigation provided by starting financial reserves and other risk mitigation tools is not sufficient to meet the TPP standard. By increasing the rate that would otherwise be sufficient to meet the revenue requirement, PNRR increases rates, which in turn increase financial reserves, thus increasing TPP until it meets the 95 percent TPP objective. This Study shows that the reserves available for risk, when combined with other tools, are sufficient to meet the TPP standard, and no PNRR is required for either year of the rate period.

3) *Liquidity Reserve Level.* The liquidity reserve level has been decreased from $50 million to $0 following the completion of an agreement between BPA and the Treasury that gives BPA access to a $750 million short-term note that can be used

for paying expenses. A deferral of a Treasury payment is registered in the Toolkit when reserves fall below this level of Liquidity Reserves defined for PS.

4) *Expanded Treasury Note (also referred to as Treasury Facility).* While the WP-10 rate proceeding was underway, BPA and the Treasury reached an agreement that expands the existing Treasury note from $300 million to $750 million. The $450 million of additional short-term borrowing capability is deemed to be available to support the Power Services TPP, functioning somewhat like additional financial reserves.

5) *Cost Recovery Adjustment Clause.* The CRAC is a downward adjustment to Residential Exchange Program (REP) benefits and an upward adjustment to the applicable power rates. The adjustment would be applied for power deliveries beginning in October following the fiscal year in which PS Accumulated Modified Net Revenues (AMNR) falls below the CRAC threshold. The AMNR threshold is set at the equivalent of $0 million in financial reserves available for risk attributed to PS.

6) *Dividend Distribution Clause.* The DDC is an upward adjustment to REP benefits and a downward adjustment to the applicable power rates. The adjustment would be applied for 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 $750 million in financial reserves available for risk attributed to PS.

Additional tools for responding to specific risks in the fish and wildlife arena are also included in the risk mitigation package, but are not modeled as part of the TPP analysis. Neither the risks nor the tools that mitigate the risks are modeled. These risks are not modeled because they are primarily functions of future human and legal actions, for which no objective probability data exist. Because BPA is not modeling the risks, it is appropriate to develop tools for these risks and then exclude the tools from the modeling. This approach accomplishes two important goals: 1) the risks are acknowledged and treated within the rate case; and 2) TPP calculations are not distorted, which would occur had the risks but not the tools been modeled, or had the tools but not the risks been modeled. These tools are the following NFB (***N***ational Marine Fisheries Service, ***F***ederal Columbia River Power System, ***B***iological Opinion) mechanisms:

1) *The NFB Adjustment.* This adjustment increases the CRAC Cap to allow recovery of increased costs or reduced revenues resulting from court-ordered changes to hydro operations, court-approved settlement of FCRPS BiOp litigation, and/or any increase in costs due to a new BiOp. The NFB Adjustment does not directly modify rates.

2) *The Emergency NFB Surcharge.* This surcharge is a separate mechanism from the NFB Adjustment, but it triggers based on the same court-related events, with the added requirement that the Agency within-year TPP be less than 80 percent. The Emergency NFB Surcharge addresses the fact that the CRAC does not produce revenues in the same fiscal year in which financial effects of an NFB trigger event occur. The Emergency NFB Surcharge is designed to recover NFB costs (or lost revenues) in the same year when BPA’s financial reserves are precariously low.

Information regarding these features is discussed in section 4 of this Study; the Wholesale Power Rate Development Study (WPRDS), WP-10-FS-BPA-05; and the General Rate Schedule Provisions, WP-10-A-02-AP02, sections II.D, II.F, and II.G.

2. OPERATING RISK ANALYSIS

BPA's traditional approach to modeling risks uses Monte Carlo simulation methodology. In this technique, the models RiskMod, NORM, and ToolKit run through 3,500 scenarios, or games. 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 are run, the output data of the set of games are either analyzed and summarized, or passed to other tools for further analysis in the ratesetting process. This analysis continues this traditional approach.

2.1 RiskMod

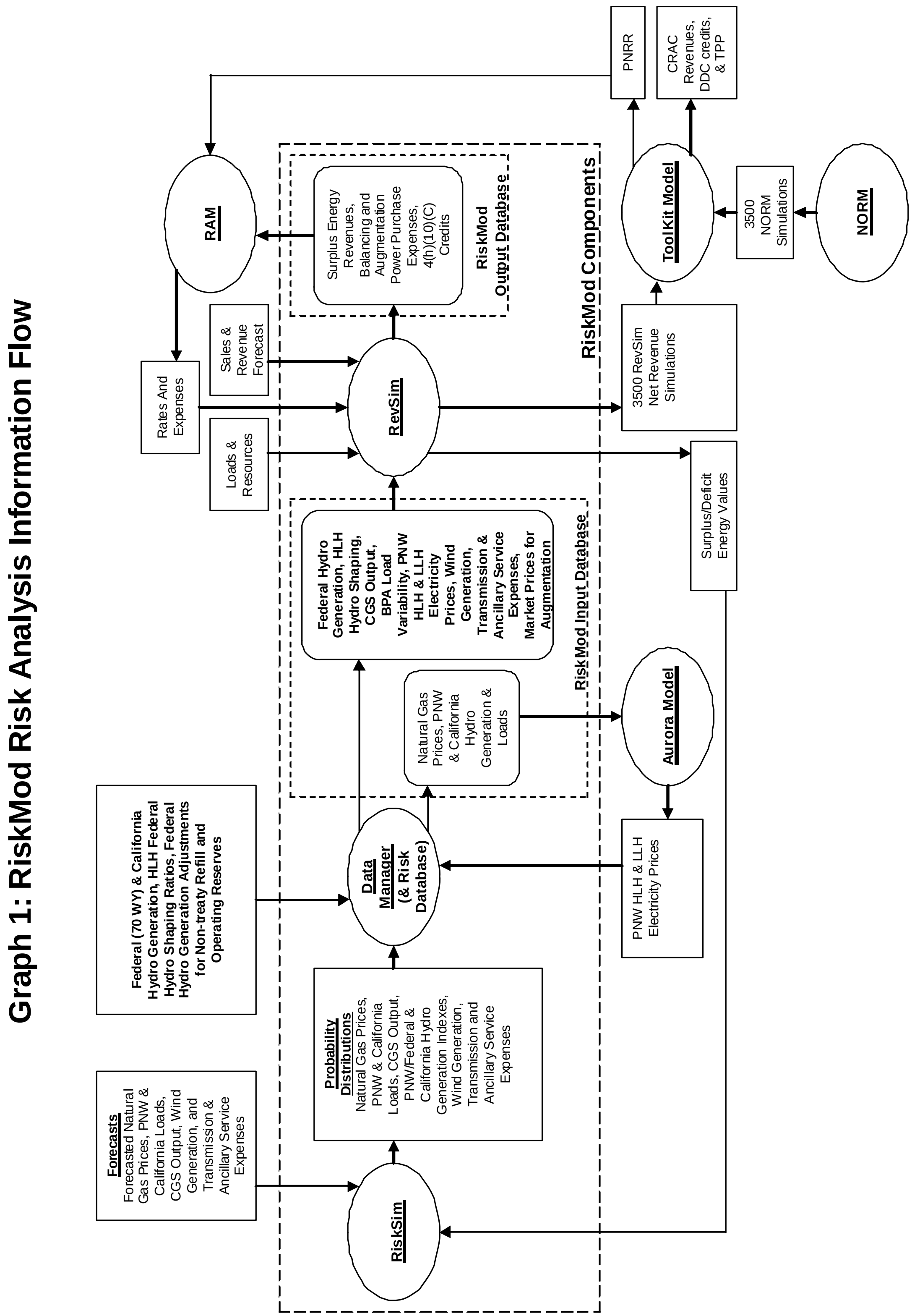
RiskMod is comprised of a set of risk simulation models, collectively referred to as RiskSim; a set of computer programs that manage data, referred to as Data Management Procedures; and RevSim, a model that calculates net revenues. RiskMod interacts with AURORA$^{xmp®}$, the Rates Analysis Model (RAM2010), and the ToolKit model during the process of performing the risk analysis documented in this Study. AURORA$^{xmp®}$ is the computer model used to develop the market price forecast. Market Price Forecast Study, WP-10-FS-BPA-03. The RAM2010 is the computer model used to calculate rates. WPRDS, WP-10-FS-BPA-05, section 3. Lastly, ToolKit is the computer model used to develop the risk mitigation package that achieves BPA's TPP standard. *See* section 4 of this Study.

Variations in monthly loads, resources, natural gas prices, and PS transmission and ancillary service expenses are simulated in RiskSim. Monthly spot market electricity prices, based on varying loads, resources, and natural gas prices, are estimated by AURORA$^{xmp®}$. Data Management Procedures facilitate the formatting and movement of data that flow to and/or from RiskSim, AURORA$^{xmp®}$, and RevSim. To estimate net revenues, RevSim uses risk data from RiskSim, spot market electricity prices from AURORA$^{xmp®}$, load and resource data from the

Loads and Resources Study, WP-10-FS-BPA-01; various revenues from the revenue forecast component of the WPRDS, WP-10-FS-BPA-05, section 4; and rates and expenses from the RAM2010.

Annual average surplus energy revenues, balancing and augmentation purchased power expenses, and section 4(h)(10)(C) credits calculated by RevSim are used in the revenue forecast and the RAM2010. Heavy Load Hour (HLH) and Light Load Hour (LLH) surplus energy values from RevSim are used in the PS Transmission and Ancillary Services Expense Risk Model, which calculates the average PS transmission and ancillary services expenses used in the Revenue Requirement Study, WP-10-FS-BPA-02. Net revenues estimated for each simulation by RevSim are input into the ToolKit model to develop the risk mitigation package that achieves BPA's 95 percent TPP standard for the two-year rate period. Graph 1 shows the processes and interactions among each of the models and studies. Additional discussion on these processes and interactions is provided in the Documentation, WP-10-FS-BPA-04A.

Graph 1: RiskMod Risk Analysis Information Flow



2.2 Risk Simulation Models (RiskSim)

Risk simulation models are developed that combine the use of logic, econometrics, and probability distributions to quantify the ordinary operating risks that BPA faces. Econometric modeling techniques capture the dependency of values through time. Parameters for the probability distributions are developed from historical data. The values sampled from each probability distribution reflect their relative likelihood of occurrence and are deviations from the base case values used in the revenue forecast, revenue requirement, and AURORA$^{xmp®}$. WPRDS, WP-10-FS-BPA-05, section 4; Revenue Requirement Study, WP-10-FS- BPA-02, section 4; Market Price Forecast Study, WP-10-FS-BPA-03, section 2.

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$^{xmp®}$. Load, resource, and natural gas price risk data for each simulation are input into AURORA$^{xmp®}$ to estimate monthly HLH and LLH spot market electricity prices. The prices estimated by AURORA$^{xmp®}$ are then downloaded into the risk database, and a consistent set of loads, resources, and spot market electricity prices are used to calculate net revenues in RevSim. The risk models run 3,500 games to produce monthly risk data for the FY 2010-2011 rate period. Thus, each of the risk models produces 3,500 rows and 24 columns of simulated data.

2.3 @RISK Computer Software

Most of the risk simulation models developed to quantify operating risks were developed in Microsoft Excel workbooks using the add-in risk simulation computer package @RISK, which is available from Palisade Corporation. @RISK allows statisticians to develop models incorporating uncertainty in a spreadsheet environment. Uncertainty is incorporated by specifying the type of probability distribution that 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 in analyses external to @RISK.

2.4 Operating Risk Factors

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

One major operating risk that is not quantified in this Study is the change to hydro operations that could result from litigation regarding FCRPS BiOps. The most likely hydro operations for the rate period under the new 2008 BiOp are incorporated into the hydro regulation study. Detail of the power and non-power requirements for the hydro regulation study for FY 2010-2011 are presented in the Loads and Resources Study, WP-10-FS-BPA-01, section 2.3.2.1.1. For additional information on how BPA intends to respond to BiOp uncertainty, *see* the description of the NFB Mechanisms in section 4 of this Study.

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

2.4.1 PNW and Federal Hydro Generation Risk Factors

The PNW and Federal hydro generation risk factors reflect the uncertainty that the timing and volume of streamflows have on monthly PNW and Federal hydro generation under specified hydro operation requirements. Federal hydro generation risk is accounted for in RevSim by inputting hydro generation estimates from the HydroSim Model and adjusting these results to account for two additional factors that impact hydro generation under the same water conditions. *See* Documentation, WP-10-FS-BPA-04A, section 2.4.1.

For FY 2010-2011, average monthly hydro generation risk is accounted for based on hydro generation estimates from the HydroSim Model for monthly streamflow patterns experienced from October 1928 through September 1998 (also referred to as the 70 water years). These monthly hydro generation data are developed by simulating hydro operations sequentially over all 840 months of the 70 water years. This analysis by HydroSim is referred to as a continuous study. *See* Loads and Resources Study, WP-10-FS-BPA-01, section 2.3.2, regarding HydroSim, continuous study, and 70 water years.

Adjustments to the average monthly hydro generation are made to each year of the 70 water year data from the continuous study for FY 2010-2011 to reflect the refilling of Non-Treaty Storage in Canada. Additional adjustments to the average monthly hydro generation are made to the 70 water year data that represent efficiency losses associated with standing ready to provide and deploy within-hour balancing reserves for both load and wind generation variability and carrying the spinning portion of the operating reserves obligation. *See* Generation Inputs Study, WP-10-FS-BPA-08, section 4.

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

The PNW and Federal hydro generation data are used to estimate prices and revenues for 3,500 two-year simulations (FY 2010-2011). 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 AURORAxmp® to quantify the impact that PNW hydro generation has on PNW electricity prices. Each simulation uses hydro generation produced from streamflow patterns for a sequential set of two water years from the continuous study for FY 2010-2011.

The initial water year (FY 2010) of the sequential set of two water years is randomly sampled from 1929 through 1998 using a uniform distribution. When the end of the 70 water years is reached (at the end of water year 1998), monthly hydro production data for water year 1929 is subsequently used. For example, if a simulation for FY 2010-2011 starts with water year 1998, the simulation uses water year 1998, as well as water year 1929, for a total of two water years. This approach is used so that each of the 70 water years is sampled an equal number of times and to maintain the historical relationships from year to year.

For FY 2010-2011, prices and net revenues are estimated such that each of the 70 water years is sampled 50 times to produce 3,500 two-year simulations. Using the hydro-regulation data for FY 2010-2011 in this continuous manner captures the dry, normal, and wet weather patterns inherent in the 70 water years and the impact these patterns have on electricity prices and BPA's net revenues over time.

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

2.4.2 PNW and BPA Load Risk Factor

The PNW and BPA load risk factor reflects the impacts that the strength of the economy and fluctuations in temperature can have on HLH and LLH spot market electricity prices and Priority Firm (PF) loads. The level of economic activity impacts the annual amount of load placed on BPA by its non-Slice PF customers. Fluctuations in load due to weather conditions cause monthly variation in loads, especially during the winter when heating loads are highest. Annual load growth variability and monthly load variability due to weather for the PNW (and indirectly for BPA) are simulated in the PNW Load Risk Model. Documentation, WP-10-FS-BPA-04A, section 2.4.2. Annual load growth variability parameters are derived from historical Western Electricity Coordinating Council (WECC) load data. *Id*. Monthly load variability for the PNW (and indirectly for BPA) is derived from daily load variability parameters used as input data in the Power Market Decision Analysis Model (PMDAM) in the 1996 rate case (Marginal Cost

Analysis Study, WP-96-FS-BPA-04); see the Documentation, WP-10-FS-BPA-04A, section 2.4.2.

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

2.4.3 California Hydro Generation Risk Factor

The California hydro generation risk factor reflects the uncertainty that the timing and volume of streamflows have 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. Documentation, WP-10-FS-BPA-04A, section 2.4.3.

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 California 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

The California load risk factor reflects the impacts that the strength of the economy and fluctuations in temperature have 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. Documentation, WP-10-FS-BPA-04A, section 2.4.4. Annual load growth variability parameters are derived from historical WECC load data. *Id*. Monthly load variability for California is derived from daily load variability parameters used as input data in PMDAM in the 1996 rate case (Marginal Cost Analysis Study, WP-96-FS-BPA-04); see Documentation, WP-10-FS-BPA-04A, section 2.4.2.

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

The natural gas price 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$^{xmp®}$. Documentation, WP-10-FS-BPA-04A, section 2.4.5; Market Price Forecast Study, WP-10-FS-BPA-03, section 3.

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 balancing purchased power costs. Conversely, lower gas prices tend to result in BPA earning lower surplus energy revenues and paying lower balancing purchased power costs.

2.4.6 CGS Nuclear Plant Generation Risk Factor

The nuclear plant generation risk factor is modeled in the CGS Nuclear Plant Risk Model and reflects the uncertainty in the amount of energy generated by CGS. Documentation, WP-10-FS-BPA-04A, section 2.4.6. Quantification of this risk is such that the average of the simulated outcomes is equal to the expected monthly CGS output specified in the Loads and Resources Study, WP-10-FS-BPA-01, section 2.3.3**.** The simulated results can vary from the output capacity of the plant to zero output.

Higher CGS generation tends to increase BPA's surplus energy revenues or reduce its power purchase expenses, because more energy is available to sell as surplus energy or displace power purchases. Lower CGS generation tends to decrease BPA's surplus energy revenues or increase its power purchase expenses, because less energy is available to sell as surplus energy or displace power purchases.

2.4.7 Wind Resource Risk Factor

The wind resource risk factor, which is quantified in RiskSim 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. Documentation, WP-10-FS-BPA-04A, section 2.4.7. The wind generation risk is quantified in four risk simulation models (the Foote Creek projects are combined and the Klondike projects are combined), such that the average of the simulated monthly generation outcomes for each wind project are similar to the expected monthly generation values included in the Loads and Resources Study, WP-10-FS-BPA-01, section 2.3.3. 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 pays for only the amount of energy that is produced.

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

2.4.8 Augmentation Cost Risk Factor

The augmentation cost risk factor reflects the uncertainty in the cost of augmentation purchases that have not been acquired prior to setting rates. The uncertainty in the cost of augmentation includes both the uncertainty around the forecast deterministic need (aMW amount) and the electricity price risk associated with meeting that need. For each iteration, these variable cost values replace the deterministic values for augmentation costs included in the revenue requirement. Revenue Requirement Study, WP-10-FS-BPA-02, section 4. The expected (base case) augmentation costs are calculated in RevSim using spot market electricity prices calculated by AURORA$^{xmp®}$ under 1937 hydro conditions and deterministic forecast values for PNW and California natural gas prices, loads, and resources (other than PNW hydro generation). The Documentation, WP-10-FS-BPA-04A, section 2.4.8, presents a sample calculation that uses this methodology to calculate expected augmentation costs for the revenue requirement.

For the purpose of determining augmentation cost risk, augmentation need (aMW) is divided into two categories. The first category of augmentation need is computed assuming CGS is operating at the forecast level of output in a non-planned-outage year for the entire rate period. This category is referred to as augmentation need not due to CGS planned outages (Category 1). The second category of augmentation need is calculated as the augmentation amount needed to replace the output of CGS during planned outages. This category of augmentation need is referred to as augmentation need due to CGS planned outages (Category 2), and is relevant for only FY 2011 in this rate proposal.

Two approaches are used for determining the price risk associated with augmentation need. The first approach (Forecast 1) for determining the price risk associated with augmentation need is the same as that used for computing secondary energy and balancing purchase power price risk, where 3,500 games are run in AURORA$^{xmp®}$ by altering natural gas prices, PNW and California loads, and PNW and California hydro generation. PNW hydro generation for all 70 water years is used in this risk run. The second approach (Forecast 2) for determining the price risk associated with augmentation need is the same methodology used for the first approach, with the exception of the hydroelectric generation forecast. In the second approach (Forecast 2), only PNW hydroelectric generation levels under 1937 hydro conditions are used for all 3,500 games per fiscal year.

For FY 2010, a fiscal year without a planned CGS outage, there is only a Category 1 augmentation need. For FY 2010, this study assumes that 50 percent of the augmentation need is met at electricity prices derived under the Forecast 1 approach, and the remaining 50 percent at electricity prices derived under the Forecast 2 approach. For FY 2011, a fiscal year with planned CGS outages, the total augmentation need is made up of both Category 1 and Category 2 augmentation needs. For FY 2011, this study assumes that 50 percent of the Category 1 augmentation need is met at electricity prices derived under the Forecast 1 approach; the remaining 50 percent of the Category 1 augmentation need is met at electricity prices derived under the Forecast 2 approach; and all the Category 2 augmentation need is met at electricity prices derived under the Forecast 1 approach.

RevSim calculates the total augmentation cost risk associated with each of the 3,500 games per fiscal year by summing the augmentation costs computed by these two approaches. The Documentation, WP-10-FS-BPA-04A, section 2.4.8, presents a sample calculation that is based on the methodology used to calculate augmentation cost risk in RevSim.

2.4.9 PS Transmission and Ancillary Services Expense Risk Factor

The transmission expense risk factor reflects the uncertainty in PS transmission and ancillary services expenses, relative to the expected expenses included in the revenue requirement. Revenue Requirement Study, WP-10-FS-BPA-02, section 4**.** 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. These asymmetrical results are due to how transmission and ancillary services expenses vary from the cost of the fixed, take-or-pay, firm transmission capacity that PS has under contract, which must be paid regardless of its use. This phenomenon reflects the fact that PS does not incur the costs of purchasing additional transmission capacity until the amounts of surplus energy sales exceed the amounts of residual firm transmission capacity after serving all firm sales. Documentation, WP-10-FS-BPA-04A, section 2.4.9.

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

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

The 4(h)(10)(C) credit risk factor is quantified in RevSim and reflects the uncertainty in the amount of 4(h)(10)(C) credits BPA receives from the U.S. Treasury. Documentation, WP-10-FS-BPA-04A, section 2.4.10. The 4(h)(10)(C) credit is the method by which BPA implements section 4(h)(10)(C) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) that allows BPA to allocate its expenditures for system-wide fish and wildlife mitigation activities to various purposes. The credit reimburses BPA for its expenditures allocated to the non-power purposes of the Federal hydro projects. BPA reduces its annual Treasury payment by the amount of the credit. This Study estimates the amount of 4(h)(10)(C) credits that is available for each of the 70 water years for FY 2010-2011 by summing the costs of the operating 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 is the percentage of the FCRPS that is attributed to non-power purposes).

The costs of the operating impacts are calculated for each of the 70 water years in RiskMod for FY 2010-2011 by multiplying spot market electricity prices from AURORA$^{xmp®}$ 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 outside of RevSim and 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 Loads and Resources Study Documentation, WP-10-FS-BPA-01, section 2.1.5. The direct program expenses and capital costs for FY 2010-2011 do not vary by water year and are documented in the Revenue Requirement Study, WP-10-FS-BPA-02, at 5.2.1.

Higher 4(h)(10)(C) credits, which normally occur under below-average streamflow conditions when the amount of power purchases that qualify for 4(h)(10)(C) credits is larger, increase net revenues. Conversely, lower 4(h)(10)(C) credits, which normally occur under above-average streamflow conditions when the amount of power purchases that qualify for 4(h)(10)(C) credits is smaller, decrease net revenues.

2.4.11 Revenue Simulation Model (RevSim)

The RevSim module within RiskMod serves two main functions in determining rates. The first function (the 70 Water Year Run) calculates surplus energy revenues, balancing and augmentation purchase power expenses, and 4(h)(10)(C) credits that are used by the RAM2010 model. The second function (the Risk Simulation Run) simulates Power Services' operating net revenue risk. Inputs to RevSim include risk data simulated by RiskSim and AURORA$^{xmp®}$, along with deterministic monthly load and resource data, monthly PF and Industrial Firm Power (IP) rates, and non-varying revenues and expenses from the Loads and Resources Study, WP-10-FS-BPA-01; section 2 of the WPRDS, WP-10-FS-BPA-05; and the RAM2010. In both functions, the RevSim module accounts for winter hedging purchases. In those months and water years when firm loads exceed resources, these winter hedging purchases reduce the amount of balancing power purchases. Conversely, in those months and water years when resources are sufficient to serve firm loads, these winter hedging purchases increase the amount of surplus energy sales.

The risk data simulated by RiskSim and monthly spot market electricity prices estimated by AURORA$^{xmp®}$ are used to calculate 3,500 net revenues in RevSim for each fiscal year from FY 2010-2011. This process yields a total of 7,000 annual net revenues, which are provided to the ToolKit model to calculate TPP.

2.4.12 Results from RiskMod

RiskMod results are used in an iterative process with the ToolKit and the RAM2010 to calculate PNRR and, ultimately, rates that provide BPA with a 95 percent TPP for the two-year rate period. The net revenues simulated in each RiskMod run depend on the level of the rates developed by the RAM2010, which in turn depend on the level of PNRR assumed when RAM2010 is run. RiskMod simulates several temporary, intermediate sets of net revenues during this iterative process. The final set of net revenues from RiskMod is the set that yields a 95 percent TPP without requiring additional PNRR.

Using 3,500 games of net revenue risk data simulated by RiskMod and NORM and mathematical descriptions of the CRAC and DDC, the ToolKit produces 3,500 games of cash flow and annual ending reserve levels. From these games, the ToolKit calculates TPP, and then analysts can change the amounts of PNRR in order to achieve TPP targets.

A statistical summary of the annual net revenues for FY 2010 and FY 2011 simulated by RiskMod using rates with $0 million in PNRR is reported in Table 1. Net revenues over the rate period average $64.5 million/year. These values represent only the operating net revenues calculated in RiskMod. They do not reflect additional net revenue adjustments in the ToolKit model due to the output from NORM, interest earned on financial reserves, and the impacts of the CRAC and DDC. Also, the average net revenues in Table 1 will differ from the net revenues shown in the Revenue Requirement Study, WP-10-FS-BPA-02, Table 1, because the latter Table 1 shows the results of a deterministic forecast that does not account for the impact of risks.

Table 1: RiskMod Net Revenue Statistics (With PNRR of $0 million)

	A	B	C
1		**FY2010**	**FY2011**
2		**(Dollars in Thousands)**	**(Dollars in Thousands)**
3	**Average**	$108,534	$20,412
4	**Median**	$109,141	$11,633
5	**Standard Deviation**	$287,824	$337,393
6			
7	**1%**	($413,955)	($598,613)
8	**2.50%**	($366,353)	($535,369)
9	**5%**	($326,714)	($480,767)
10	**10%**	($286,825)	($423,143)
11	**15%**	($227,663)	($362,696)
12	**20%**	($169,906)	($297,174)
13	**25%**	($108,701)	($228,232)
14	**30%**	($51,229)	($162,886)
15	**35%**	($9,528)	($113,202)
16	**40%**	$27,086	($69,557)
17	**45%**	$69,964	($30,261)
18	**50%**	$109,141	$11,633
19	**55%**	$148,823	$54,934
20	**60%**	$186,152	$95,486
21	**65%**	$223,298	$140,214
22	**70%**	$260,122	$189,455
23	**75%**	$299,832	$233,186
24	**80%**	$350,396	$292,178
25	**85%**	$403,916	$356,178
26	**90%**	$473,000	$445,206
27	**95%**	$578,430	$584,529
28	**97.50%**	$690,879	$721,852
29	**99%**	$849,364	$914,396

3. NON-OPERATING RISK ANALYSIS

3.1 Non-Operating Risk Model (NORM)

NORM is an analytical risk tool that quantifies the impacts of risks other than operating risks in the ratesetting process. It was first introduced and adopted in the WP-02 rate proceeding. NORM models the non-operating risks of Power Services and the risks of the corporate costs that are covered by power rates. Transmission Services' risks are not included in the analysis. In addition, NORM models some changes in revenue, and some changes in cash. While RiskMod is used to quantify risks having to do with various economic, load, and generation resource capability variations, NORM is used to model risks surrounding projections of non-operations-related revenue or expense levels in the Power Services revenue requirement. The main NORM modules model the accrual impacts of the included risks, and an accrual-to-cash adjustment translates the net revenue impacts into cash impacts. NORM supplies 3,500 games (or iterations) of both net revenue and cash impacts of the risks that it models. The outputs from NORM, along with the outputs from RiskMod, are input into the ToolKit model to assess the TPP.

3.1.1 Methodology

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

3.1.2 Data Gathering and Development of Probability Distributions

To obtain the data used to develop the probability distributions used by NORM, BPA risk staff interviewed subject matter experts (SMEs) for each capital and expense item modeled. 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 risk staff use the information provided to develop the probability distributions.

3.1.3 Inputs

3.1.3.1 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
4) Nuclear Electric Insurance Limited (NEIL) Insurance Premiums

NORM captures uncertainty around Base O&M and NEIL insurance costs only. For Base O&M, NORM assumes that the most likely outcome is the amount determined in the Integrated Program Review (IPR) process. The minimum and maximum values are distributed based on historical deviations of actual and forecast CGS O&M. For NEIL insurance premiums, risk is modeled around the level of earnings on the NEIL fund. Member utilities receive annual distributions based on the level of these earnings, which in turn lowers the premiums they pay.

The distributions for CGS O&M are shown in the Documentation, WP-10-FS-BPA-04B, Table 43. Distributions are shown for FY 2010 and FY 2011, and also for the total of the two years.

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

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

1) Additional costs if a security event occurs
2) Additional costs if a fish event occurs
3) Additional system needs
4) Additional extraordinary maintenance
5) Base O&M (for Reclamation only)

Historically, Reclamation has underrun its O&M budget. Therefore, NORM includes a probability distribution around future Reclamation Base O&M expenditures, with a minimum value of $2 million less than the IPR value, and a maximum value equal to the IPR value (i.e., the value determined in the IPR process).

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 and the probability that an outage event will occur.

The distributions for total COE and Reclamation O&M are shown in the Documentation, WP-10-FS-BPA-04B, Table 44. Distributions are shown for FY 2010 and FY 2011, and also for the total of the two years.

3.1.3.3 Colville/Spokane Settlement

For the Colville settlement, the payment to the Colville Tribe equals a base annual charge, which is calculated as a base annual price times the generation output from Grand Coulee. The base annual charge is subject to both a floor and ceiling. NORM models the uncertainty in the price per kWh paid, Consumer Price Index (CPI), and generation output from Grand Coulee.

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.

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 the 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 variability around Grand Coulee generation, a mean and standard deviation is calculated for the average annual output of the 50 historical water years. The mean and standard deviation are used as parameters for a normal probability distribution generated by @Risk. The 50 years of data are provided in the Documentation, WP-10-E-BPA-04B, Table 45.

Using the data described above, NORM calculates a base annual payment to the Colville Tribe, which equals the base annual price times the draw for that year's output from Grand 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 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.

Within the rate period, a similar settlement with the Spokane Tribe could go into effect by means of legislation. NORM includes an assumption of a 60 percent probability that the legislation will pass and thus payments to the Spokane Tribe are 60 percent likely to occur over the entire rate period. The payments equal 29 percent of the payments made to the Colville Tribe.

The distributions for Colville Settlement payments are shown in the Documentation, WP-10-FS-BPA-04B, Table 46. Distributions are shown for FY 2010 and FY 2011, and also for the total of the two years. Similar graphs for the Spokane Settlement payments are shown in the Documentation, WP-10-FS-BPA-04B, Table 47.

3.1.3.4 Power Services Internal Operations

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

1) PS System Operations
2) PS Scheduling
3) PS Marketing and Business Support
4) Corporate G&A

For Corporate G&A, NORM assumes the IPR value as most likely, with a minimum value of 5 percent lower and a maximum value of 10 percent higher.

To model uncertainty around the remaining cost items, NORM creates a probability distribution for each item, with a minimum that is 10 percent lower than the IPR values and a maximum that is 10 percent higher.

The distributions for total Internal Operations Costs, including Corporate G&A, that are modeled in NORM are shown in the Documentation, WP-10-FS-BPA-04B, Table 48. Distributions are shown for FY 2010 and FY 2011, and also for the total of the two years.

3.1.3.5 Fish & Wildlife Expenses

NORM models uncertainty around four categories of fish and wildlife mitigation program expense, as described below.

3.1.3.5.1 BPA Direct Program Costs for Fish and Wildlife

The costs of BPA's Direct Program for fish and wildlife are uncertain, in large part because the actual pace of implementation cannot be known and there is a significant chance that measures will not be implemented as rapidly as planned, especially in FY 2009 and 2010. This does not reflect any uncertainty in BPA's commitment to the plans, merely a realistic understanding that it can take time to start programs, and the expenses of the programs may not actually be incurred in the fiscal years in which BPA plans for them to be incurred. This uncertainty is modeled by Pert distributions with most likely expense deviation values of $0 for all three years; minimum (maximum underrun) values of -$50 million, -$35 million, and -$20 million for FY 2009, 2010, and 2011; and maximum values of $10 million, $10 million, and $20 million for the three years, respectively. This results in expected value net revenue impacts of $6.7 million, $4.2 million, and $0 for the three years, respectively. Graphs of the distributions for the BPA Direct Program expense, along with additional descriptive statistics, are shown in the Documentation, WP-10-

FS-BPA-04B, Table 49. Distributions are shown for FY 2010 and FY 2011, and also for the total of the two years.

3.1.3.5.2 USF&W Service Lower Snake River Hatcheries

Uncertainty in the costs of the USF&W Service Lower Snake River Hatcheries is modeled as a symmetric Pert distribution with a most likely impact of $0, a minimum value (largest negative impact) of -$2 million, and a maximum value of $2 million. The expected value is $0. The distributions for risk over the Lower Snake River Hatcheries expense are shown in the Documentation, WP-10-FS-BPA-04B, Table 50.

3.1.3.5.3 Bureau of Reclamation Leavenworth Complex O&M

NORM models uncertainty of the O&M expense of Reclamation's Leavenworth Complex using the same symmetric Pert distribution for all three years, FY 2009-2011. The most likely value for the deviation from revenue requirement numbers is $0; the minimum value (largest negative deviation) is -$500 thousand; and the maximum value is $500 thousand. This results in an expected value net revenue impact of $0 for each of the three years. Distributions for Leavenworth Complex O&M expense are shown in the Documentation, WP-10-FS-BPA-04B, Table 51.

3.1.3.5.4 Corps of Engineers Fish Passage Facilities

NORM models uncertainty of the cost of COE's fish passage facilities using the same symmetric Pert distribution for all three years, FY 2009-2011. The most likely value for the deviation from revenue requirement numbers is $0; the minimum value (largest negative deviation) is -$3 million; and the maximum value is $3 million. This results in an expected value net revenue impact of $0 for each of the three years. Distributions for Fish Passage Facilities expense are shown in the Documentation, WP-10-FS-BPA-04B, Table 52.

3.1.3.6 BiOp Secondary Sales Risk

The 2008 FCRPS BiOp is incorporated into the hydro studies. Loads and Resources Study, WP-10-FS-BPA-01, section 2.3.2.1.1. This BiOp includes performance standards. It may be necessary to make changes to the operational regime to meet the BiOp standards, resulting in decreased net secondary revenue. This risk continues as long as the current 2008 BiOp remains in effect (the separate risk of changes to FCRPS operations or expenses arising from litigation over either the 2004 or the 2008 FCRPS BiOp are treated with the two NFB mechanisms, described below in section 4). A Pert distribution of this risk is created and used for each of the two fiscal years in the rate period and for FY 2009. For FY 2010 and FY 2011, the most likely value is $0 change, the minimum value (largest negative impact) is -$40 million, and the maximum value is $5 million. This results in an expected value net revenue impact of -$5.8 million for each of the two years. For FY 2009, the most likely value is $0 change, the minimum value (largest negative impact) is -$20 million, and the maximum value is $2.5 million. This results in an expected value net revenue impact of -$2.9 million. Distributions for BiOp Secondary Sales Risk are shown in the Documentation, WP-10-FS-BPA-04B, Table 53.

3.1.3.7 Capital Expenditure Risk

For this Study, capital expenditure uncertainty is generally not being modeled in NORM. New capital expenditures are debt financed. This results in the net revenue effect being distributed over several years (the precise duration depends on the type of financing). A small fraction of the capital expenditure is distributed to net revenues for FY 2010 and FY 2011 for the calculation of TPP. Current evaluation and past modeling show the effect of capital expenditures risk on TPP to be minimal in the WP-10 rate period.

The one kind of capital risk that is modeled in NORM is associated with the CGS condenser replacement scheduled for FY 2011. CGS capital additions are modeled around historical variability, with added uncertainty around the costs of the condenser replacement. This capital uncertainty affects Energy Northwest (EN) debt service for the calculation of TPP. The distribution of CGS debt service is shown in the Documentation, WP-10-FS-BPA-04B, Table 54.

3.1.3.8 Interest Rate and Inflation Risk

Interest rate and inflation risk is currently not being modeled in NORM. Current evaluation and past modeling show the effect of interest rate and inflation risk on TPP to be minimal in the WP-10 rate period.

3.1.3.9 Federal Depreciation, Amortization, and Net Interest Distribution Risk

Depreciation, amortization, and net interest distribution variability are driven primarily by interest rate risk. As a result, they are not being modeled in NORM for the WP-10 rate period.

3.1.3.10 CGS Main Condenser Replacement Risk

In 2011, EN is planning to replace the main condenser at CGS. This project is scheduled concurrently with the regular CGS refueling outage, scheduled to begin April 9, 2011. During this project, CGS will not be producing power. Risks of the main condenser replacement are modeled around revenue variability due to changes in the outage duration.

CGS outage duration risk is modeled as lost revenues due to variability in the duration of the planned maintenance outage in 2011. Increases or decreases in downtime of the CGS plant result in changes in MWh generated. This translates to decreased or increased revenues for Power Services. This revenue variability is a function of plant outage duration; monthly flat AURORA[xmp®] prices from the Market Price Forecast Study, WP-10-FS-BPA-03, section 2.5;

and CGS aMW generation, documented in the Loads and Resources Study, WP-10-FS-BPA-01, section 2.3.3.

SMEs have provided outage duration estimates of a minimum of 65 days and a most likely outage of 87 days. A high estimate for the outage is approximately twice the most likely duration. The probability distribution of the outage duration is shown in the Documentation, WP-10-FS-BPA-04B, Table 55. The outage duration is effectively capped at 175 days. The outage is scheduled to begin on April 9, 2011. The last day of the rate period is September 30, 2011, 174 days later. Any energy lost after this date would not apply to the FY 2010-2011 rates.

To calculate the revenue effect of the outage duration, for each of the 3,500 games of flat monthly prices from AURORA$^{xmp®}$, a duration is drawn from the outage duration distribution. This duration is then applied to the monthly prices multiplied by the aMW normally generated by CGS when the plant is in service, multiplied by the hours in the month. This calculation results in a lost revenue figure from the plant being down. The same methodology is applied using the deterministic outage duration assumed in the Loads and Resources Study, WP-10-FS-BPA-01, section 2.3.3. This lost revenue less the lost revenue calculated using outage duration variability results in 3,500 revenue changes due to the CGS outage duration. The distribution of these revenue changes is shown in the Documentation, WP-10-FS-BPA-04B, Table 56.

3.1.3.11 Revenue from Sales of Services to Wind Generators

In FY 2010 and FY 2011, TS will provide services to wind generators in the BPA Balancing Authority Area (BAA). TS will charge these customers on the basis of their installed MW of capacity. TS will obtain from PS the generation inputs needed to support these services and will pay PS for the generation inputs. PS estimates the costs of providing the forecast quantity of generation inputs to TS to meet the needs of wind generation on the BPA system. The costs can be characterized as having two components, embedded costs and variable costs.

Because the quantity of wind generation in BPA's BAA is not known with certainty, there is financial risk due to the possibility that the quantity will differ from the forecast, and TS will receive either more or less revenue for wind services sales than forecast. TS and PS will each bear half of the part of this risk that relates to the recovery of embedded costs. PS will bear the part of this risk that relates to the recovery of variable costs, which is offset by risk to realization of net secondary revenues.

The variable cost calculations reflect the deoptimization of the power system that results from setting aside some system capability to support installed wind generation. If less wind generation than forecast is actually installed, TS will receive less revenue for such services, but PS will be able to generate greater net secondary revenues than forecast. The incremental net secondary revenue will be, within BPA's ability to calculate such factors, equal to and offsetting the decrease in TS revenues. TS will pass to PS all actual revenue from sales of services to wind generators that is designated to recover the variable costs of generation inputs provided by PS. In this way, TS faces no risk due to variation in the total quantity of wind associated with the recovery of the variable costs of generation inputs. PS bears the entire risk of deviations in the recovery of the variable cost component, but because this risk is offset by the corresponding impact on PS net secondary revenue, PS faces no significant financial risk. Therefore, BPA does not face significant risk for the recovery of the variable costs of generation inputs.

The recovery of embedded costs, however, is subject to risk, and this risk will be shared equally by the two business lines, as follows. If the amount of installed wind capacity is lower than the rate case forecast in a year in the rate period, BPA will calculate the portion of the TS revenue shortfall that was intended to recover embedded costs of generation inputs. TS payments to PS for the embedded costs of generation inputs will then be equal to the forecast amount minus half of the embedded-cost portion of the TS revenue shortfall. Similarly, if the amount of installed wind capacity exceeds the rate case forecast for a year in the rate period, TS payments to PS for the embedded costs of generation inputs for that year will be equal to the rate case forecast for that year plus half of the embedded-cost portion of the TS revenue increase.

This risk is modeled using estimates of low, most likely, and high quantities of installed wind capacity for FY 2010 and 2011. The low and high estimates are interpreted to represent the 2.5th and 97.5th percentiles. Distributions are fitted that matched those parameters. In each of the games in the risk analysis, a random draw of installed wind capacity is made from the distributions. If this random result is lower (higher) than the most likely forecast, then a negative (positive) financial result is calculated by multiplying the difference in capacity by the annual cost per installed MW for embedded costs of generation inputs.

Another risk to the revenue from sales of services to wind generators has been created by BPA’s decision to offer a reduced rate to wind generators who are able to supply some of the reserves needed for integration of their generation into the BAA starting October 1, 2010. BPA forecasts that the only self-supply that is very likely is self-supply of imbalance reserves by Iberdrola. If Iberdrola is able to provide its own imbalance reserves in FY 2011, BPA’s revenue would be reduced by the amount of BPA’s reserves charge for the imbalance component that is based on embedded costs, which has been calculated to be $0.8449 per kW of installed capacity per month. Probabilities that Iberdrola would be able to supply its own energy imbalance reserves for 0 percent, 25 percent, 50 percent, and 100 percent of its forecast 1200 MW of installed FY 2011 capacity, averaged over the year, are used to reflect this risk.

Fifty percent of the financial result of these two risks is then applied to the net revenues for both TS and PS in their respective risk analyses. Distributions for Services for Wind Generators revenue are shown in the Documentation, WP-10-FS-BPA-04B, Table 57.

3.1.3.12 Accrual-to-Cash (ATC)

One of the inputs to the ToolKit (through NORM) is the ATC. 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 3,500 games and feeds the results of these games into the ToolKit model. The ToolKit also accepts as input 3,500 net revenue scenarios from RiskMod. The 3,500 NORM-computed ATC adjustments make the necessary changes to convert these net revenue scenarios (accruals) into the equivalent reserves value (cash) needed by ToolKit to calculate TPP.

Because not all changes in expenses result in a similar change in cash, ATC is modeled probabilistically in NORM for this rate case. NORM uses the deterministic ATC Table (Table 2 on the following page) 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 3: EN Direct Pay Prepaid Expense
3) Line 4: Slice True-up included in All Other
4) Line 6: EN Debt Service included in income statement
5) Line 8: Planned Advance Amortization of Federal Debt

Table 2: RISK MODELING ACCRUAL TO CASH ADJUSTMENTS (in $Millions)

A	B	C	D	E	F
			FY 2009	FY 2010	FY 2011
1	Depreciation/Amortization		$181.229	$198.024	$207.119
2	Interest Adjustments		($45.937)	($45.937)	($45.937)
3	ENW Direct Pay Prepaid Expense		$26.647	$7.652	($41.497)
4	All Other (see lines 14 thru 23 below)		$33.876	($1.363)	($27.270)
5	**Sub Total Lines 1 - 4**		$195.815	$158.376	$92.415
6	Add: EN Debt Service Before Refinancing		$544.793	$546.641	$562.811
	Add: @Risk Debt Service Adjustment		$0.000	$0.000	$0.000
7	Adjust for Current Estimated ENW Debt Service (PBL only)		($411.859)	($546.641)	($562.811)
8	Less: Planned Advanced Amortization of Federal Debt		($116.295)	$0.000	$0.000
9	**Sub Total Lines 6 - 8**		$16.639	$0.000	$0.000
10	Less: Scheduled Federal Debt Amortization		($110.339)	($244.673)	($162.163)
11	Less: Revenue/Reserve financing/Cash transfers to TBL		($40.000)	$0.000	$0.000
12	**Sub Total Lines 10 - 11**		($150.339)	($244.673)	($162.163)
13	**Accrual to Cash Adjustment (Lines 5 + 9 + 12)**		**$62.115**	**($86.297)**	**($69.748)**
			$37.030	$0.000	$0.000
14	**All Other**				
15	Net Slice True up lag into (out of) current year		$1.057	$10.652	($16.224)
16	Investment Accruals and Interest Paid adjustment		$11.626	$0.000	$0.000
17	Cash lags and other timing adjustments				
18	Terminated contracts & Settlements & 4(h)(10)(C) true up		$3.373	($1.544)	($5.224)
19	Energy Efficiency Projects		$0.265	($10.471)	($5.822)
20	Inter Company Revenue Net of Expense		$0.000	$0.000	$0.000
21	Actual to forecast cash adjustment		$22.555	$0.000	$0.000
22	Other Miscellaneous		($5.000)	$0.000	$0.000
23	**TOTAL All Other**		**$33.876**	**($1.363)**	**($27.270)**

3.2 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 3,500 games. The ToolKit uses this file in its calculations of TPP. Summary statistics and distributions for each fiscal year are shown in the Documentation, WP-10-FS-BPA-04B, Table 58.

4. RISK MITIGATION

4.1 Treasury Payment Probability (TPP)

One of BPA's policy objectives for this rate case is to meet its TPP standard. As described in section 1 of this Study, this standard for a two-year rate period is 95 percent for the risks, financial reserves, and tools attributed to PS.

4.2 ToolKit Overview

The ToolKit is an Excel 2003 spreadsheet that is used to evaluate Power Services' ability 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 "TK_Main" worksheet). The ToolKit reads in data from two external files, one each from RiskMod and NORM. Most of the modeling of risks is performed by RiskMod and NORM, as described in Sections 2 and 3 of this Study. 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 functions.

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 PS, and thus on TPP. 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 and all other sources of liquidity are also exhausted. In this Study, the amount of liquidity needed in the form of financial reserves is $0 million. The ToolKit is run for 3,500 "games" or iterations. TPP is calculated by dividing the number of those games where each of the two years in the rate period ends with at least $0 million in PS reserves by 3,500. The ToolKit calculates the TPP and other risk statistics and reports results, and allows analysts to calculate how much PNRR is needed, if any, to meet the TPP standard.

4.3 Risk Mitigation Tools Incorporated into the Risk Analysis and Mitigation Study

The preceding sections of this study describe the risks that are modeled explicitly. This section describes the tools for mitigating those risks. Some of these tools are modeled and included in this Study; others are not modeled, specifically the NFB Adjustment and the Emergency NFB Surcharge, but are included as part of BPA's risk mitigation package; other tools are no longer used and are therefore not modeled. The following sections describe each of these risk mitigation tools.

4.3.1 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 ratesetting purposes, it is the financial reserves available for risk attributed to the generation function (PS reserves) that are considered when measuring TPP. Financial reserves available to the generation function comprise cash and investments held by the 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 needed by completing the borrowing.

PS reserves mitigate financial risk by serving as a temporary source of cash, that is, liquidity, 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 will be replenished so they will be available in later years.

Some financial reserves attributed to PS are not considered to be available for risk and thus are not included in the starting financial reserves or any other part of the TPP calculation. In this rate case, financial reserves available for risk attributed to PS exclude financial reserves that BPA is holding due to the suspension of payment of REP Settlement Benefits. These funds are expected to be completely distributed by a combination of REP payments to investor-owned utilities (IOUs) and refunds (in the form of rate credits) to consumer-owned utilities (COUs).

PNRR. Analyses of BPA's TPP are conducted using current projections of PS financial reserves and other sources of liquidity in its rate cases. If the TPP is below the standard established in the 10-Year Financial Plan, 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 PS financial 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 associated 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, and 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 caused by PNRR 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.

4.3.2 Other Liquidity Tools

BPA relies on financial reserves for mitigating two types of financial risk that are related but can be usefully distinguished. The risk that is the primary subject of the Risk Analysis and Mitigation Study is the possibility that BPA might not have sufficient cash on September 30 to fully meet its obligation to the Treasury for that fiscal year. BPA's TPP standard, described in the introductory section of this Study, defines a way to measure this risk (TPP) and a standard that reflects the Agency's tolerance for this risk (95 percent for a two-year rate period). The second risk can be called within-year liquidity risk—the risk that, at some time within a fiscal year, BPA will not have sufficient cash to meet its immediate financial obligations (whether to the Treasury or to other creditors), even if BPA might have enough cash later in that year.

Financial reserves serve as one of BPA's main tools for mitigating Treasury payment risk, and also for mitigating liquidity risk. In each recent rate case, a need for reserves for liquidity ("liquidity reserves," formerly known as "working capital") has been defined. This level is based on a determination of BPA's total need for liquidity, and a subsequent determination of how much of that need is properly attributed to PS.

4.3.2.1 Direct Pay of EN Budget

BPA will continue the "Direct Pay" method of funding Energy Northwest's cash needs. The change from Net Billing to Direct Pay made approximately $200 million in cash available for paying the Treasury on September 30 that had in earlier years been sent to Energy Northwest in advance of Energy Northwest's actual need for the cash. This means that BPA does not need to maintain as much other liquidity (primarily financial reserves) to meet the same TPP standard.

4.3.2.2 The Treasury Note

In FY 2008, BPA reached an agreement with the U.S. Treasury that makes a $300 million short-term note available to the Administrator for up to two years that can be used to pay expenses. BPA's Finance and Risk staffs have concluded that this note can be prudently relied on as a source of liquidity. In FY 2009, BPA and the Treasury agreed to expand this note to $750 million.

4.3.2.3 The Net Impact on the Liquidity Reserve Level

During the development of the WP-10 Initial Proposal, BPA began research into its total need for within-year liquidity and concluded that the $300 million Treasury Note was adequate to meet BPA's need for within-year liquidity. With the expansion of the Treasury Note, BPA considers $300 million to be available for within-year liquidity needs, and $450 million to be available for TPP support, augmenting the liquidity provided by financial reserves. Therefore, no PS reserves need to be set aside to provide liquidity (i.e., liquidity reserves = $0).

4.3.3 The Cost Recovery Adjustment Clause (CRAC)

In most rate cases since 1993, BPA has employed Cost Recovery Adjustment Clauses (CRACs) or Interim Rate Adjustments (IRAs) as upward rate adjustment mechanisms that can respond to the financial risks BPA faces. Financial reserves were the original metric used for determining whether a CRAC should trigger. BPA decided in the WP-02 Final Proposal to use AMNR rather than financial reserves, because net revenues are a more standard financial metric than reserves (cash). BPA will use AMNR for FY 2010-2011.

4.3.3.1 Description of the CRAC

The CRAC for FY 2010-2011 is essentially the same as the CRAC for FY 2007-2009. It is an annual upward adjustment in energy and load variance rates subject to the CRAC. In addition, because the REP is now being implemented using the PF Exchange rate, the CRAC also creates a reduction in REP benefits. The CRAC is limited to the annual collection amount, or cap, of $300 million. The threshold for triggering the CRAC is an amount of PS AMNR as accumulated since the end of FY 1999. The AMNR threshold values are calibrated to be equivalent to PS financial reserve levels of $750 million.

The CRAC (and NFB Adjustment and DDC) calculations will be made shortly before the beginning of each fiscal year in the rate period. A forecast of the year-end PS AMNR will be made after the Third Quarter Review and then compared to the thresholds for the CRAC and the DDC. If this PS AMNR forecast is below the CRAC threshold, an upward rate adjustment and a downward REP benefit adjustment would be calculated for the duration of the upcoming fiscal year. If the forecast is above the threshold for the DDC, a downward rate adjustment and upward REP benefit adjustment would be calculated to distribute dividends to applicable rates for the duration of the upcoming fiscal year.

Table 3: CRAC Annual Thresholds and Caps
[Dollars in Millions]

A	B	C	D	E
AMNR Calculated at End of Fiscal Year	**CRAC Applied to Fiscal Year**	**CRAC Threshold as Measured in AMNR**	**Approx. Threshold as Measured in PS Reserves**	**Maximum CRAC Recovery Amount (CRAC Cap)***
2009	2010	-$876.5	$0	$300
2010	2011	-$790.7	$0	$300

* The CRAC Cap may be modified by NFB Adjustments

4.3.3.1.1 Administrator's Discretion to Adjust the CRAC

The CRAC methodology includes a process that allows the Administrator to look ahead to the remaining fiscal year(s) of the rate period and determine whether any or all of the CRAC is needed to help BPA maintain its financial standing. The ability to apply discretion in the CRAC adjustment is tempered by the requirement to maintain the TPP standard for the remainder of the rate period. This requirement protects the TPP standard but provides for lower rates if the Administrator determines that s/he will not need all of the additional revenues to meet the TPP standard. A CRAC that is calculated for FY 2010 may be reduced from the calculated amount as long as the two-year TPP for FY 2010-2011 remains at or above 95.0 percent. The Administrator may adjust the parameters (i.e., the Cap and Threshold) for the CRAC applicable to FY 2011 to maintain the FY 2010-2011 TPP. A CRAC that is calculated for FY 2011 may be reduced from the calculated amount as long as the one-year TPP for FY 2011 would still be at or above 97.5 percent.

4.3.4 Dividend Distribution Clause (DDC)

One of the financial policy objectives for this rate case is to ensure that PS reserves do not accumulate to excessive levels. The DDC is triggered if PS AMNR is above (instead of below as with the CRAC) a threshold, and if so, there is a downward adjustment to rates and an upward adjustment to REP benefits. 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 4: DDC Thresholds
[Dollars in Millions]

A	B	C	D
AMNR Calculated at End of Fiscal Year	**DDC Applied to Fiscal Year**	**DDC Threshold as Measured in AMNR**	**Approx. Threshold as Measured in PS Reserves**
2009	2010	-$126.5	$750
2010	2011	-$40.7	$750

4.4 Tools Not Modeled in the ToolKit

4.4.1 The NFB Mechanisms

Being certain it can cover its fish and wildlife costs is an extremely important objective for BPA. Because of pending and possible litigation over BPA's fish and wildlife obligations, it is impossible to determine now with any certainty the approach to fish recovery and the associated costs that BPA will ultimately be required to implement during FY 2010-2011.

The possibilities for FY 2010-2011 are many and mostly unknowable at this time, and as a result probabilities cannot be estimated for any particular scenario that might be created. Because the uncertainty is open-ended, it is necessary to have an equally open-ended adjustment mechanism to ensure that BPA can fund its fish and wildlife obligations despite the uncertainty. This Study includes two related features that help to mitigate the financial risk to BPA and its stakeholders caused by uncertainty over future fish and wildlife obligations under the FCRPS BiOp and their financial impacts. These are the NFB Adjustment and the Emergency NFB Surcharge, collectively referred to as the NFB Mechanisms. The NFB Mechanisms are explained in the General Rate Schedule Provisions, WP-10-A-02-AP-02, section II.G.

An NFB Trigger Event is one of the following four kinds of events that results in changes to BPA's FCRPS Endangered Species Act (ESA) obligations compared to those in the most recent Power rate Final Proposal as modified prior to this Trigger Event:

1) A court order in *National Wildlife Federation vs. National Marine Fisheries*, CV 01-640-RE, or any other case filed regarding an FCRPS BiOp issued by NMFS (now known as NOAA Fisheries Service), 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 FCRPS BiOp
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 Mechanisms protect the financial viability of BPA and its financial resources from the potentially large impact of changes in the operation of the Columbia River hydro system or in fish and wildlife program costs that are directly related to FCRPS BiOp litigation (as specified above).

4.4.1.1 The NFB Adjustment

The NFB Adjustment would result in an upward adjustment to the CRAC Cap for any year in the rate period if one or more NFB Trigger Events with financial effects occurs in the previous year (unless one or more Emergency NFB Surcharges in the previous year completely collected additional revenue equal to the financial effects). The NFB Adjustment could modify the CRAC Cap applicable to rates for FY 2010 or 2011 based on changes in modified net revenue in FY 2009 or FY 2010.

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 PS AMNR is above the threshold, there will be no adjustment to rates, because the CRAC will not trigger at all. If the NFB Adjustment triggers and PS AMNR is below the threshold, but not by more than $300 million, the CRAC will trigger for an amount that is below the original Cap. On the other hand, if PS AMNR is more than $300 million below the threshold, the NFB Adjustment will allow BPA to recover more than the $300 million Cap.

As a result of the Partial Resolution of Issues in the WP-07 rate proceeding, BPA and parties agreed that any revenues above $300 million resulting from the NFB Adjustment to the Cap should be collected over a different revenue basis than regular CRAC revenues. This treatment continues in this Study. CRAC revenue amounts below the original CRAC Cap (before the NFB Adjustment Calculation) would be collected from LLH and HLH energy and Load Variance rates. CRAC revenue amounts in excess of the CRAC Cap, as shown in Table 3, would be collected from LLH and HLH energy, Load Variance, and Demand rates proportionally under the firm power rate schedules subject to the CRAC. As a result, CRAC revenue amounts for the financial impacts of the NFB Adjustment would be 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 would require two percentages to be applied to applicable rates if the NFB Adjustment triggers in a year that the CRAC Amount is greater than the original Cap amount of $300 million.

4.4.1.2 The Emergency NFB Surcharge

The Emergency NFB Surcharge results in nearly immediate increases in net revenue for PS if (a) an NFB Trigger Event occurs, and (b) BPA is in a "Cash Crunch" and cannot prudently wait until the next year to collect incremental net revenue. A Cash Crunch is defined to exist when BPA calculates that the within-year Agency TPP (i.e., including both TS and PS) is below 80 percent. The Surcharge increases net revenue by making an upward adjustment to specified Power rates and reductions in REP benefits.

The Emergency NFB Surcharge addresses the fact that the CRAC does not produce revenues until the year following the fiscal year in which Financial Effects of a Trigger Event are experienced. Thus, the financial benefit of the NFB Adjustment may be too late if BPA is in a Cash Crunch when a Trigger Event occurs. For the WP-10 rates, the Surcharge may be implemented in FY 2010 if the events required to impose the Surcharge occur in that fiscal year or in FY 2011 if the requisite events occur in that year.

4.4.1.3 Multiple NFB Trigger Events

There can be multiple NFB Trigger Events in one year. If BPA is not in a Cash Crunch in such a year, then there will be only one final analysis per year that calculates the NFB Adjustment to the Cap on the CRAC applicable to the next fiscal year. If BPA is in a Cash Crunch in such a year, there may be more than one Emergency NFB Surcharge calculated and applied during that year. For example, there could be more than one court order in FY 2010 that increases the financial impacts of operations in FY 2010. If BPA were in a Cash Crunch, there could be an Emergency NFB Surcharge calculated for each of the Trigger Events and applied during FY 2010. If BPA were not in a Cash Crunch in FY 2010, both of these triggering events would be included in the calculation of the single NFB Adjustment that would increase the Cap on the CRAC applicable to FY 2011.

Each NFB Adjustment affects only one year. However, because the comparison used to calculate the NFB Adjustment is between the actual operation for fish and the operation assumed in the rate case (as modified prior to a Trigger Event), it is possible for a Trigger Event to affect operations for more than one year of the rate period. For example, a decision in FY 2009 may affect operations in both FY 2009 and FY 2010. The analysis of the total financial impact during FY 2009 for adjusting the Cap on the CRAC applying to FY 2010 would be separate from the analysis of the total financial impact during FY 2010 for adjusting the Cap on the CRAC applying to FY 2011 (or for implementing an Emergency NFB Surcharge during FY 2010). Increases in the financial impacts during FY 2011 are not covered by the NFB Adjustment in the proposed rates, because incorporating those increases through an NFB Adjustment would require a CRAC during FY 2012, and the rates for FY 2012 are not covered by this rate case. However, financial impacts during FY 2011 are covered by the Emergency NFB Surcharge provisions applicable to FY 2011 in the proposed rates.

4.4.1.4 Flexible PF Rate Program

During the WP-07 rate proceeding, BPA and its customers developed, and later implemented, the Flexible PF Rate Program as part of an endeavor to identify additional sources of liquidity. The Flexible PF Rate Program allowed BPA to increase the amount payable by participating customers for power delivered in a given month and thereafter reduce the amount payable for power delivered to such customers in subsequent months. The program increased BPA's liquidity by shaping power revenues to cover extraordinary cash flow requirements. Because the expanded Treasury Note and projections of financial reserves provide enough liquidity to meet BPA's TPP standard without requiring additional liquidity or PNRR, the Flexible PF Rate Program has been allowed to expire.

4.5 ToolKit Modifications and Changes in TPP Modeling

Changes in risk mitigation since the WP-07 rate proceeding and since the WP-07 Supplemental rate proceeding are reflected in changes in how the ToolKit models TPP. The following sections cover areas where the risk mitigation tools in this Study differ from the WP-07 or WP-07 Supplemental risk mitigation tools.

4.5.1 IOU REP Settlement Benefits Replaced by REP Program

The 2000 REP Settlement that was modeled in the WP-07 rate proceeding risk analysis was overturned by the U.S. Court of Appeals for the Ninth Circuit in May 2007. Like the WP-07 Supplemental rate proceeding, this Study contains provisions for the operation of a traditional REP rather than the REP Settlement terms that were used in the WP-07 Final Proposal. For risk mitigation, this is relevant mainly in how the CRAC and DDC would be calculated.

BPA participated in extensive discussions with IOUs, COUs, and other parties about how to resume the operation of the REP. These discussions, among other things, culminated in some decisions by BPA about the REP that guided the design of the CRAC and DDC with regard to REP benefits. The GRSPs in the WP-07 Supplemental Final Proposal define the CRAC and DDC as applying to several PF rates, including the PF Exchange rate, but did not specify exactly how a CRAC or DDC would apply to the PF Exchange rate. A CRAC or DDC will not affect REP benefits by modifying the PF Exchange rate and then recalculating benefits for each exchanging utility; instead, any CRAC or DDC will be applied proportionally to all exchanging utilities' REP benefits. A portion of any CRAC or DDC will be allocated to REP benefits, and this portion will be applied as a reduction to or increase in REP benefits in proportion to the magnitude of the REP benefits previously calculated for each exchanging utility for that fiscal year. GRSPs, WP-10-A-02-AP02, sections II.D and II.F. This Study adopts this approach to applying CRACs and DDCs to REP benefits of exchanging IOUs and COUs.

The RAM2010 was used to test how REP Benefits would change and how the rates subject to the CRAC and DDC would change if quantities of PNRR were added or subtracted, taking into account the 7(b)(2) rate test impacts and impacts on the Slice true-up. These calculations show that for a CRAC that generates an additional $200 million of incremental net revenue for BPA, reductions in REP Benefits account for 27.8 percent of this amount and increases in non-Slice PF, IP, and other rates subject to the CRAC would generate 80.2 percent of this amount. These amounts total more than 100 percent because the reductions in REP Benefits would lead to a decrease in Slice expense and would therefore increase the size of the True-Up BPA owes the Slice customers (or decrease the size of the True-Up Slice customers owe BPA), partially offsetting the net revenue benefit of the CRAC. This methodology is used to define how a CRAC or DDC would apply to REP Benefits. After the amount of incremental net revenue to be recovered by a CRAC is determined, or the amount of decremental net revenue to be distributed by a DDC is determined, portions allocated to REP Benefits and to non-Slice PF, IP and other rates subject to the CRAC are determined: 27.8 percent of the incremental or decremental amounts is allocated to REP Program benefits, and 80.2 percent is allocated to non-Slice PF, IP, and other rates subject to the CRAC. REP Benefit amounts are increased or decreased proportionally across all exchanging utilities. A percentage is calculated, using the most recent forecast of revenues from rates subject to the CRAC, that when applied to the subject rates will produce 80.2 percent of the total CRAC or DDC amount. That percentage is then applied to the subject rates for the next fiscal year.

4.5.2 Treasury Payment Deferral Modeling

In the event of a deferral of payment of principal to the Treasury in the ToolKit, the ToolKit assumes that BPA will track the balance of payments that have been deferred and will repay this balance to the Treasury at its first opportunity. "First opportunity" is defined for TPP calculations as the first time PS ends a fiscal year with more than $100 million above its minimum liquidity level. The PS minimum liquidity level in this proposal is $0 million (*see* section 4.3.2.3), so the ToolKit is modeling the repayment as occurring as soon as possible while not bringing the level of PS reserves below $0 million at the end of the fiscal year following the deferral. The same applies to subsequent fiscal years if the repayment cannot be completed in the first year after the deferral.

4.5.3 New Outputs

Some of the output features that were added to the ToolKit during the WP-07 rate case are no longer relevant or are no longer working properly due to lack of time to update them after removing the logic that modeled the REP Settlement Agreements.

4.6 ToolKit Inputs and Assumptions

4.6.1 Risk Analysis Model (RiskMod)

RiskMod distributions are created for the current year, FY 2009, and the rate period, FY 2010-2011. TPP is measured only for the two-year rate period, but the starting reserves available for risk for FY 2010 depend on events yet to unfold in FY 2009; these runs reflect that FY 2009 uncertainty

4.6.1.1 Non-Operating Risk Model (NORM)

NORM distributions are created for FY 2009-2011 that reflect the uncertainty around non-operating expenses.

4.6.2 Inputs and Assumptions on the ToolKit Main Page

4.6.2.1 Starting PS Reserves Available for Risk

The FY 2009 starting PS reserves have a known value of $874.9 million based upon the FY 2008 Fourth Quarter Review. Each of the 3,500 games starts with this value. This figure is determined from the total BPA reserves at the end of FY 2008 by excluding reserves attributed to TS. An additional computational step then excludes funds that were in the Bonneville Fund due to the cessation of the REP Settlement Agreements. At the end of FY 2008, approximately $195 million of funds collected from rates that BPA had planned to pay to exchanging IOUs remained in the Bonneville Fund. Since these funds are expected to be completely distributed to IOUs and COUs in response to the ruling in *Golden NW Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007), the funds are not considered to be available for risk.

4.6.2.2 Starting AMNR

The FY 2009 starting AMNR value of $69.0 million is based upon the FY 2008 Fourth Quarter Review. Each of the 3,500 games starts with this value.

4.6.2.3 Treatment of Treasury Deferrals

Treasury deferrals are treated using the "Hybrid" logic described in section 4.5.2.

4.6.2.4 Other Agency Reserves Temporarily Available

This Study does not rely on any of the reserves attributed to TS as available for use in meeting the PS TPP requirement. Therefore, cells J14:J16 are set to zero.

4.6.2.5 Interest Rate Earned on Reserves

Interest earned on PS reserves is calculated at the rate of 4.70 percent per year.

4.6.2.6 Interest Credit Assumed in the Net Revenues

A basic feature of the ToolKit is the ability to calculate interest earned on PS reserves separately for each game. The revenue requirement includes an assumption of interest earned on reserves, and that assumption is deterministic; that is, it does not vary from game to game. To capture the interest effects of this variability in the TPP calculations, the revenue requirement assumptions about interest earned on reserves are backed out of all ToolKit games and replaced with game-specific calculations of interest credit. The revenue requirement amounts that are backed out are $45.93 million, $41.03 million, and $41.02 million for FY 2009, FY 2010, and FY 2011, respectively.

4.6.2.7 The Cash Timing Adjustment

The cash timing adjustment reflects the interest credit impact of the typical shape of PS 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 PS cash payments to the Treasury are not evenly spread throughout the year, but instead are heaviest in September, PS 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 $10.0 million for each of FY 2010 and FY 2011.

4.6.2.8 Cash Lag for PNRR

These numbers appear in the input section of the ToolKit's main page, but they are calculated automatically. When the ToolKit calculates a change in PNRR (either a decrease, or more typically, an increase), it calculates how much of the cash generated by the increased rates would be received in the subsequent year, since September revenue is not received until October. In order to treat ToolKit-generated changes in the level of PNRR on the same basis as amounts of PNRR that have already been assumed in the rates calculation, the ToolKit calculates this lag for PNRR that is embedded in the RiskMod output file the ToolKit reads. Because this Study does not require PNRR, there are no cash adjustments for PNRR.

4.6.2.9 Other Cash Adjustments

There are no adjustments of this type in this Study.

4.7 ToolKit Output

4.7.1 TPP

The two-year TPP is 97.9 percent. No deferrals are registered for FY 2009 or FY 2010. There are 72 deferrals in FY 2011. In FY 2011, the expected value of the amount deferred is $2.4 million, for an average of $126.1 million per deferral.

4.7.2 Ending PS Reserves

Known starting PS reserves for FY 2009 are $874.9 million. The expected values of ending reserves for FY 2009 through 2011 are $710 million, $719 million, and $568 million. Over 3,500 games, the range of ending FY 2011 reserves is from $0 to $2,428 million (which would result in a DDC for FY 2012 if the WP-12 rate case includes a DDC comparable to that of the WP-07, WP-07 Supplemental, or WP-10 rate proposals). The 50 percent confidence interval for ending reserves is $678-743 million for FY 2009, $494-920 million for FY 2010, and $220-849 million for FY 2012.

4.7.3 CRAC and DDC

The CRAC does not trigger in any of the 3,500 games in either of the two years of the rate period.

The DDC triggers 746 times in FY 2010 (21 percent), with an average size of $34 million, yielding an expected value of $7 million for that year. In FY 2011, the DDC triggers 1,614 times (46 percent), yielding an average of $228 million per triggering, and an expected value of $105 million of dividend distributions for the year.

4.7.4 Other ToolKit Results

Other ToolKit results are shown in the Documentation, WP-10-FS-BPA-04B, TK Main.