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

2007 Wholesale Power Rate Case Initial Proposal

RISK ANALYSIS STUDY

November 2005

WP-07-E-BPA-04

RISK ANALYSIS

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COMMONLY USED ACRONYMS

AANR	Audited Accumulated Net Revenues
AC	Alternating Current
AER	Actual Energy Regulation
Affiliated Tribes	Affiliated Tribes of Northwest Indians
AFDUC	Allowance for Funds Used During Construction
AGC	Automatic Generation Control
aMW	Average Megawatt
Alcoa	Alcoa Inc.
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
ANRT	Accumulated Net Revenue Threshold
AOP	Assured Operating Plan
APS	Ancillary Products and Services (rate)
ASC	Average System Cost
Avista	Avista Corporation, Water Power Division
BASC	BPA Average System Cost
BiOp	Biological Opinion
BOR	Bureau of Reclamation
BPA	Bonneville Power Administration
BP EIS	Business Plan Environmental Impact Statement
Btu	British thermal unit
C&R Discount	Conservation and Renewables Discount
C&R	Cost and Revenue
CalPX	California Power Exchange
CAISO	California Independent System Operator
CBFWA	Columbia Basin Fish & Wildlife Authority
CBP	Columbia Basin Project
CCCT	Combined-Cycle Combustion Turbine
CEC	California Energy Commission
CFAC	Columbia Falls Aluminum Company
Cfs	Cubic feet per second
COB	California-Oregon Border
COE	U.S. Army Corps of Engineers
ConMod	Conservation Modernization Program
COSA	Cost of Service Analysis
Council	Northwest Power Planning and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRC	Conservation Rate Credit
CRITFC	Columbia River Inter-Tribal Fish Commission
CSP	Customer System Peak
CSPE	Columbia Storage Power Exchange
CT	Combustion Turbine
CWA	Clear Water Act

CY	Calendar Year (Jan-Dec)
DC	Direct Current
DDC	Dividend Distribution Clause
DJ	Dow Jones
DMP	Data Management Procedures
DO	Debt Optimization
DOE	Department of Energy
DROD	Draft Record of Decision
DSIs	Direct Service Industrial Customers
DSR	Debt Service Reassignment
ECC	Energy Content Curve
EFB	Excess Federal Power
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
Energy Northwest, Inc.	Formerly Washington Public Power Supply System (Nuclear)
Energy Services	Energy Services, Inc.
EPA	Environmental Protection Agency
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
EWEB	Eugene Water & Electric Board
F&O	Financial and Operating Reports
FBPF	Forward Flat-Block Price Forecast
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FERC	Federal Energy Regulatory Commission
FELCC	Firm Energy Load Carrying Capability
Fifth Power Plan	Council's Fifth Northwest Conservation and Electric Power Plan
FPA	Federal Power Act
FPS	Firm Power Products and Services (rate)
FSEA	Federal Secondary Energy Analysis
F&WCA	Fish and Wildlife Coordination Act
FY	Fiscal Year (Oct-Sep)
GAAP	Generally Accepted Accounting Principles
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

HELM	Hourly Electric Load Model
HLFG	High Load Factor Group
HLH	Heavy Load Hour
HOSS	Hourly Operating and Scheduling Simulator
ICNU	Industrial Customers of Northwest Utilities
ICUA	Idaho Consumer-Owned Utilities Association, Inc.
IOU REP Settlement benefits	Investor-Owned Utilities Residential Exchange Program Settlement benefits
IOUs	Investor-Owned Utilities of the Pacific Northwest
IP	Industrial Firm Power (rate)
IP TAC	Industrial Firm Power Targeted Adjustment Charge
IPC	Idaho Power Company
ISC	Investment Service Coverage
ISO	Independent System Operator
KAF	Thousand Acre Feet
kcfs	kilo (thousands) of cubic feet per second
K/I	Kilowatt-hour/Investment Ratio for Low Density Discount
ksfd	thousand second foot day
kV	Kilovolt (1000 volts)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LCP	Least-Cost Plan
LDD	Low Density Discount
LLH	Light Load Hour
LOLP	Loss of Load Probability
LRSCP	Lower Snake River Compensation Plan
m/kWh	Mills per kilowatt-hour
MAC	Market Access Coalition Group
MAF	Million Acre Feet
MC	Marginal Cost
MCA	Marginal Cost Analysis
MCS	Model Conservation Standards
M/M	Meters/Miles-of-Line Ratio for Low Density Discount
Mid-C	Mid-Columbia
MIMA	Market Index Monthly Adjustment
MIP	Minimum Irrigation Pool
MMBTU	Million British Thermal Units
MNR	Modified Net Revenues
MOA	Memorandum of Agreement
MOP	Minimum Operating Pool
MORC	Minimum Operating Reliability Criteria
MT	Market Transmission (rate)
MW	Megawatt (1 million watts)
MWh	Megawatt-hour
NCD	Non-coincidental Demand

NEC	Northwest Energy Coalition
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NEW	Northwestern Energy
NF	Nonfirm Energy (rate)
NFB Adjustment	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp) Adjustment
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon Border
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPV	Net Present Value
NR	New Resource Firm Power (rate)
NRU	Northwest Requirements Utilities
NT	Network Transmission
NTP	Network Integration Transmission (rate)
NTSA	Non-Treaty Storage Agreement
NUG	Non-Utility Generation
NWPP	Northwest Power Pool
NWPPC	Northwest Power Planning Council
NWPPC C&R	Northwest Power Planning Council Cost and Revenues Analysis
O&M	Operation and Maintenance
OMB	Office of Management and Budget
OPUC	Oregon Public Utility Commission
OURCA	Oregon Utility Resource Coordination Association
ORC	Operating Reserves Credit
OY	Operating Year (Aug-Jul)
PA	Public Agency
PacifiCorp	PacifiCorp
PATH	Plan for Analyzing and Testing Hypotheses
PBL	Power Business Line
PDP	Proportional Draft Points
PDR	Power Discharge Requirement
PF	Priority Firm Power (rate)
PFBC	Pressurized Fluidized Bed Combustion
PFR	Power Function Review
PGE	Portland General Electric Company
PGP	Public Generating Pool
PMA	Power Marketing Agencies
PNCA	Pacific Northwest Coordination Agreement

PNGC	Pacific Northwest Generating Cooperative
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration/Point of Interconnection
POM	Point of Metering
PPC	Public Power Council
PPLM	PP&L Montana, LLC
Project Act	Bonneville Project Act
PSA	Power Sales Agreement
PSC	Power Sales Contract
PSE	Puget Sound Energy
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	Public or People's Utility District
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
Reclamation	Bureau of Reclamation
Renewable Northwest	Renewable Northwest Project
RD	Regional Dialogue
REP	Residential Exchange Program
RFA	Revenue Forecast Application
RFP	Request for Proposal
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
RMS	Remote Metering System
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RTF	Regional Technical Forum
RTO	Regional Transmission Operator
SCCT	Single-Cycle Combustion Turbine
SCRA	Supplemental Contingency Reserve Adjustment
Shoshone-Bannock	Shoshone-Bannock Tribes
SOS	Save Our Wild Salmon
Slice	Slice of the System product
STREAM	Short-Term Risk Evaluation and Analysis Model
SUB	Springfield Utility Board
SUMY	Stepped-Up Multiyear
SWPA	Southwestern Power Administration
TAC	Targeted Adjustment Charge
TBL	Transmission Business Line
tcf	Trillion Cubic Feet
TCH	Transmission Contract Holder
TDG	Total Dissolved Gas
TPP	Treasury Payment Probability

Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
UAI Charge	Unauthorized Increase Charge
UAMPS	Utah Associated Municipal Power Systems
UCUT	Upper Columbia United Tribes
UDC	Utility Distribution Company
UP&L	Utah Power & Light
URC	Upper Rule Curve
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VOR	Value of Reserves
WAPA	Western Area Power Administration
WECC	Western Electricity Coordinating Council
WPAG	Western Public Agencies Group
WPRDS	Wholesale Power Rate Development Study
WSPP	Western Systems Power Pool
WUTC	Washington Utilities and Transportation Commission
WY	Watt-Year
Yakama	Confederated Tribes and Bands of the Yakama Nation

1. INTRODUCTION

1.1 Background

The Federal Columbia River Power System (FCRPS), operated on behalf of the ratepayers of the PNW by BPA and other Federal agencies, faces many uncertainties during the FY 2007-2009 rate period. Among these uncertainties, the largest revolve around hydro conditions, market prices and river operations for fish recovery. In order to provide a high probability of making its U.S. Treasury payments, BPA performs a Risk Analysis as part of its rate-making process. In this Risk Analysis, BPA identifies key risks, models their relationships, and then analyzes their impacts on net revenues (total revenues less expenses). BPA subsequently evaluates in the ToolKit Model the Treasury Payment Probability (TPP) resulting from the rates, risks, and risk mitigation measures described here and in the Wholesale Power Rate Development Study (WPRDS). If the TPP falls short of BPA's standard, additional risk mitigation revenues, such as PNRR and CRAC revenues are incorporated in the modeling in ToolKit until the TPP standard is met.

Increased wholesale market price volatility and six years of drought have significantly changed the profile of risk and uncertainty facing BPA and its stakeholders. These present new challenges for BPA in its effort to keep its power rates as low as possible while fully meeting its obligations to the U.S. Treasury. As a result, the risk BPA faces in not receiving the level of secondary revenues that have been credited to power rates before receiving those funds is greater.

In addition to market price volatility, BPA also faces uncertainty around the financial impacts of operations for fish programs in FY 2006 and in the FY 2007-2009 rate period. A new Biological Opinion or possible court-ordered change to river operations in FY 2006 through FY 2009 may reduce BPA's net revenues included Initial Proposal. Finally, the FY 2007-2009 risk analysis includes new operational risks as well as a more comprehensive analysis of non-operating risks. Both the operational and non-operational risks will be described in Section 2.0 of this study.

Given these risks, if rates are designed using BPA's traditional approach of only adding Planned Net Revenues for Risk (PNRR), power rates would need to recover a much larger "risk premium" to meet BPA's TPP standard. As an alternative to high fixed risk premiums, BPA is proposing a risk mitigation package that combines PNRR with a variable rate mechanism similar to the cost recovery adjustment mechanisms used in the FY 2002-2006 rate period. The proposed risk mitigation package is less expensive on a forecasted basis because the rates can be adjusted on an annual basis to respond to uncertain financial outcomes. BPA is also proposing a Dividend Distribution Clause (DDC) to refund reserves in excess of $800M to customers in the event net revenues in the next rate period exceed current financial forecasts.

1.1.1 BPA's TPP Standard

BPA is setting power rates to achieve a 92.6 percent probability that PBL reserves will be sufficient to make its U.S. Treasury payments on time and in full over the three-year rate period. BPA adopted a long-term policy, the 10-Year Financial Plan, in its 1993 Final Rate Proposal, calling for setting rates that build and maintain financial reserves sufficient for the agency to achieve a 95 percent probability of meeting U.S. Treasury payments in full and on time for a two-year rate period. *See,* 1993 Final Rate Proposal, Administrator's Record of Decision (ROD), WP-93-A-02, at 72. The 10-Year Financial Plan has not expired. It was intended to be in effect until replaced, and it has not been replaced.

In the 1996 rate case, this 95 percent, two-year TPP standard was translated to an equivalent percentage for five-year rate periods by assuming consecutive rate periods are statistically independent and that the five-year TPP standard should provide the same total probability of making all 10 payments in two five-year periods as would be provided by five two-year periods in each of which the 95 percent TPP standard is met. This target probability is 77 percent:

$$.95^5 = .77378$$

The desired five-year percentage is the square root of that number:

$$.77378^{1/2} = .87965$$

This figure was rounded to 88.0 percent. To check, calculate the TPP for two consecutive five-year periods:

$$.88^2 = .774$$

It can be convenient to think of this process as being based on a one-year TPP:

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

$$.9747^5 = .88$$

Note that 97.47 percent is the translation of the two-year standard into an equivalent percentage for a *one-year rate period;* this is not the standard for a single year within a multi-year rate period. BPA does not have a TPP standard for individual years within multi-year rate periods.

This initial rate proposal and the risk mitigation package included in it are intended to achieve a three-year TPP of 92.6 percent, which is the three-year equivalent of a two-year 95 percent TPP:

$$.9747^2 = .95,$$

$$.9747^3 = .926.$$

1.2 Overview

BPA's policy objectives for this proposal (*See,* Leathley *et al*., WP-07-E-BPA-08) include the following:

(1) A rate design that meets BPA financial standards, including meeting a 92.6 percent TPP (which is equivalent to a 95 percent two-year TPP);

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

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

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

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

(6) The assumption that other agency reserves that are not needed to meet other business line TPP standards can be considered to be temporarily available for PBL rate-setting purposes to the extent that this can be done without harming the interests of TBL or its customers; and

(7) Include in the risk mitigation package a way to recover from increased costs or reduced revenues resulting from court-ordered changes to hydro operations, court approved settlements over the Biological Opinion (BiOp) and/or any increase in costs due to a new BiOp.

In this initial rate proposal, BPA has analyzed its power risks and is proposing risk mitigation tools designed to achieve the 92.6 percent TPP standard for the generation function. The following items are included in the BPA's TPP modeling:

(1) Starting PBL Reserves. Starting financial reserves include cash in the BPA Fund and the deferred borrowing balance attributed to the generation function. The expected value of PBL's starting FY 2007 reserves is $381 million.

(2) The Temporary Availability for PBL Rate-Setting of Other Agency Reserves. BPA will assume that any financial reserves attributed to TBL above the level required to satisfy TBL's 95 percent TPP standard for FY 2006 – 2007 can be considered to be temporarily available to PBL for rate-setting purposes. As determined by using the

TBL risk model, updated during the 3rd Quarter Review of FY 2005, TBL reserves in FY 2007 could be reduced by $55 million without depressing the TBL TPP for FY 2006 – 2007 below 95 percent. Therefore, $55 million of Agency reserves will be considered to be available to PBL in FY 2007 only for PBL rate-setting purposes. PBL will plan that any temporary use of these reserves in FY 2007 would be completely made up for in such a way that TBL rates would be no higher than if BPA had not made this assumption. The reserves attributed to TBL for FY 2008 will not be reduced, and PBL rate-setting will not assume any availability of these reserves for FY 2008 or FY 2009.

(3) Cost Recovery Adjustment Clause (CRAC). The CRAC is a separate upward adjustment to the requirements power rates for energy published in the Final ROD that will be made if accumulated modified net revenues (AMNR) attributable to the generation function fall below the thresholds shown in Table 1. Any CRAC rate will be shown on a separate line on customers' bills. The CRAC is applicable to Priority Firm Power (PF) [Preference (excluding Slice), Exchange Program, and Exchange Subscription], and Industrial Firm Power (IP-07). It is also applicable to New Resources Firm Power (NR-07) rate schedules and BPA's contractual obligations for Irrigation Rate Mitigation. In addition it will be applied to the calculation of IOU REP Settlement and DSI benefits. It is not applicable to Pre-Subscription contracts, Slice loads, or the TAC portion of the PF rate. The CRAC may trigger for each year of the three-year rate period. The adjustment will be applied to power deliveries beginning in October following the FY in which Accumulated Modified Net Revenues (AMNR) fall below the CRAC threshold. Any such increase in FY 2007-2009 would remain in effect through the fiscal year. The level of planned rate increase is limited to the lower of the annual Maximum Planned Recovery Amount in

Table 1 below, or the amount by which accumulated net revenues are below the CRAC threshold.

Table 1
CRAC Trigger Thresholds and Annual Caps

AMNR Calculated at end of Fiscal Year	CRAC Applied to Fiscal Year	CRAC Threshold (AMNR) ($ millions)	Approx. Threshold as Measured in PBL Reserves ($ millions)	Maximum CRAC Recovery Amount (Cap) ($ millions)
2006	2007	-$193	$470	$300
2007	2008	-$36	$500	$300
2008	2009	-$45	$500	$300

(4) [N]ational Marine Fishery Service, [F]ederal Columbia River Power System, [B]iological Opinion Rate Adjustment Mechanism (NFB Adjustment). An adjustment mechanism that increases the annual cap on the CRAC to allow for recovering increased costs or reduced revenues resulting from court-ordered changes to hydro operations, court-approved settlements over the BiOp and/or any increase in costs due to a new BiOp. The adjustment to the CRAC caps may be made each year (FY 2007- 2009) of the three-year rate period. The NFB Adjustment does not directly modify rates. It adjusts the cap on the annual collection of the CRAC. The level of increase in the caps is calculated by the difference in PBL net revenues when comparing those revenues before and after the action took place. The difference may result in an increase to the CRAC cap for one or more years following the year in which the costs or reduced revenues occurred. For example, if a court-ordered change in operations decreases net revenues in FY 2006, the NFB adjustment would increase the annual cap on the collection of CRAC revenues during FY 2007. If the

decision was a multi-year decision, the caps would adjust for all the years the decision impacts.

The calculation of the actual CRAC percentage adjustment depends on AMNR. It is possible that a court-ordered change in, for example, FY 2006 would lead to an increase in the CRAC cap for FY 2007, but that FY 2006 AMNR would be above the CRAC threshold and that there would be no CRAC for FY 2007. It is also possible that a court-ordered change in FY 2006 would result in a higher CRAC cap for FY 2007, and that FY 2006 AMNR would then produce a CRAC that would collect more CRAC revenue than the proposed cap of $300 million.

(5) Planned Net Revenues for Risk (PNRR). PNRR is a component of the revenue requirement that is added to annual expenses. By increasing the rate calculated from the revenue requirement, PNRR increases rates which in turn increase financial reserves, thus increasing TPP.

(6) Dividend Distribution Clause (DDC). BPA is also proposing criteria for distributing "dividends" to purchasers of products subject to the CRAC if AMNR is forecasted to be above the equivalent of $800 million in financial reserves attributed to PBL. The distribution of any amounts to power customers would be made through credits to their power bills over 12 equal monthly installments in the following year.

Table 2
DDC Trigger Thresholds

AMNR Calculated at End of Fiscal Year	DDC Applied to Fiscal Year	DDC Threshold (AMNR) ($ millions)	Approx. Threshold as Measured in PBL Reserves ($ millions)
2006	2007	$137	$800
2007	2008	$264	$800
2008	2009	$255	$800

BPA's traditional approach to modeling risks is to use *Monte Carlo* simulation methodology. In this technique, the models RiskMod, RiskSim, ToolKit, and NORM run through 3000 *games* or iterations. In each game, each of the financial uncertainties is randomly assigned a value based on input specifications for that uncertainty. After all of the games have been run, the output data on the set of games can be analyzed and summarized in various ways, or passed to other tools.

2. RISK ANALYSIS

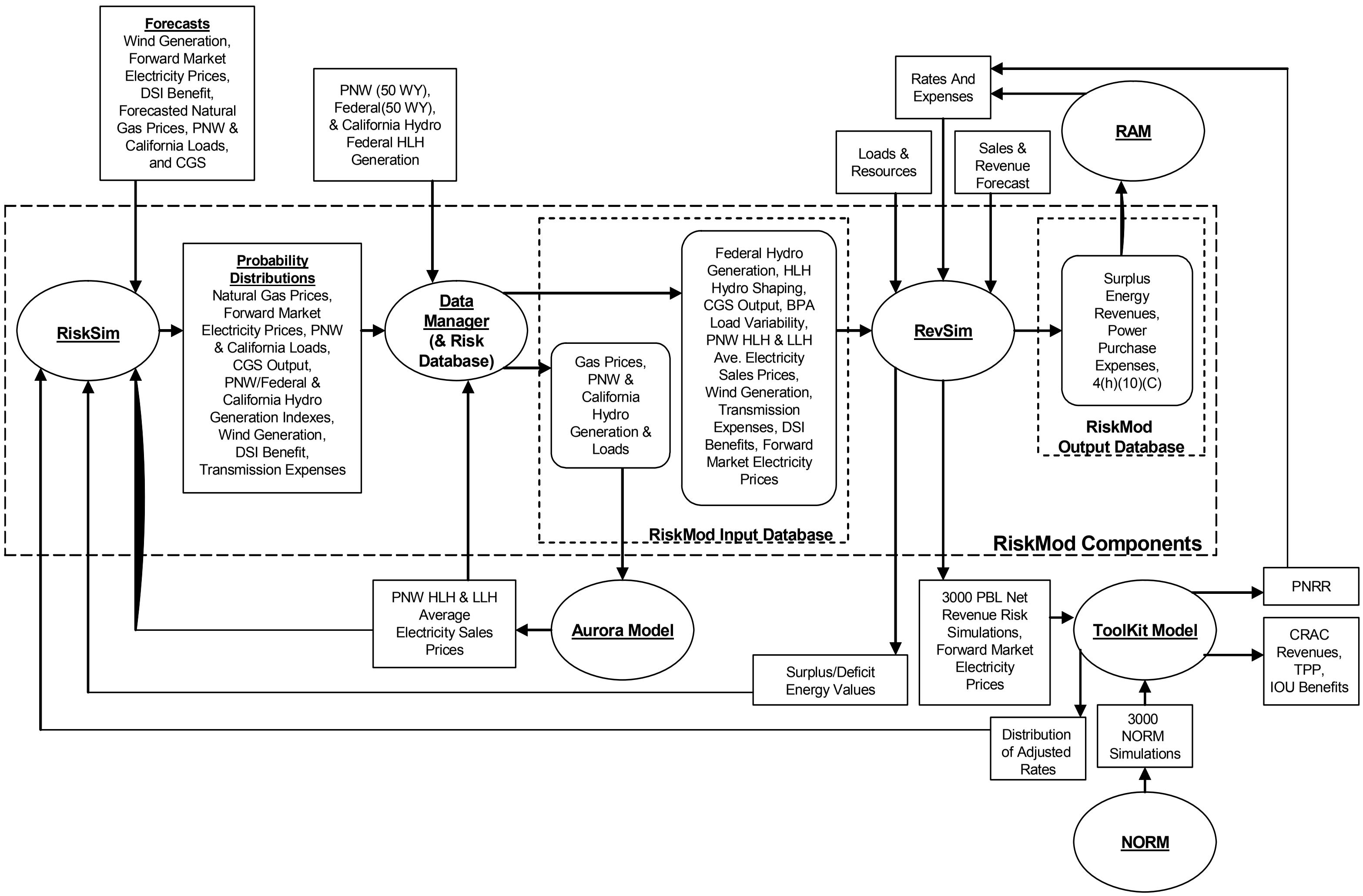
2.1 RiskMod

RiskMod is comprised of a set of risk simulation models, collectively referred to as RiskSim; a set of computer programs that manage data referred to as Data Management Procedures; and RevSim, a model that calculates net revenues. RiskMod interacts with AURORA, the Rates Analysis Model (RAM2007), and the ToolKit Model during the process of performing the Risk Analysis Study. AURORA is the computer model being used to perform the Market Price Forecast Study (*See,* Market Price Forecast Study, WP-07-E-BPA-03), the RAM2007 is the computer model being used to calculate rates (*See,* Wholesale Power Rate Development Study, WP-07-E-BPA-05), and the ToolKit is the computer model being used to develop the risk mitigation package that achieves BPA's TPP standard. *See,* Section 3 of this Study regarding the ToolKit Model.

Variations in monthly loads, resources, natural gas prices, forward market electricity prices, transmission expenses, and aluminum smelter benefit payments are simulated in RiskSim. Monthly spot market electricity prices for the simulated loads, resources, and natural gas prices are estimated by AURORA. Data Management Procedures facilitate the formatting and movement of data that flow to and/or from RiskSim, AURORA, and RevSim. RevSim uses risk data from RiskSim, spot market electricity prices from AURORA, loads and resources data from the Load Resource Study, WP-07-E-BPA-01, various revenues from the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-07-E-BPA-05, and rates and expenses from the RAM2007 to estimate net revenues.

Annual average surplus energy revenues, purchased power expenses, and section 4(h)(10)(C) credits calculated by RevSim are used in the Revenue Forecast and the RAM2007. Heavy Load Hour (HLH) and Light Load Hour (LLH) surplus energy values from RevSim are used in the Transmission Expense Risk Model. Net revenues estimated for each simulation by RevSim and forward market electricity prices estimated by RiskSim are input into the ToolKit Model to develop the risk mitigation package that achieves BPA's 92.6 percent TPP standard for the three-year rate period. The processes and interaction between each of the models and studies are depicted in Graph 1. Additional discussion on these processes and interactions are provided in the Risk Analysis Study Documentation, WP-07-E-BPA-04A.

Graph 1: RiskMod Risk Analysis Information Flow



2.2 Risk Simulation Models (RiskSim)

To quantify the effects of operational risks, BPA developed risk models that combine the use of logic, econometrics, and probability distributions to quantify the ordinary operational risks that BPA faces. Econometric modeling techniques are used to capture the dependency of values through time. Parameters for the probability distributions were developed from historical data. The values sampled from each probability distribution reflect their relative likelihood of occurrence and are deviations from the base case values used in the Revenue Forecast, Revenue Requirement, and AURORA. *See,* the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-07-E-BPA-05; the Revenue Requirement Study, WP-07-E- BPA-02; and discussion of AURORA in the Market Price Forecast Study, WP-07-E-BPA-03.

The monthly outputs from these risk simulation models are accumulated into a computer file to form a risk data base which contains values lower than, higher than, or equal to the base case values used in the Revenue Forecast component of the Wholesale Power Rate Development Study, Revenue Requirement Study, and AURORA. *Id*. Loads, resources, and natural gas price risk data for each simulation are input into AURORA to estimate monthly heavy load hour (HLH) and light load hour (LLH) spot market electricity prices. The prices estimated by AURORA are then downloaded into the risk database and a consistent set of loads, resources, and spot market electricity prices are used to calculate net revenues in RevSim.
The risk models run 3000 games to produce monthly risk data for FY 2007-2009 for this rate filing. Thus, each of the risk models produces 3000 rows and 36 columns of simulated data.

2.3 @RISK Computer Software

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

2.4 Operational Risk Factors

In the course of doing business, BPA manages risks that are unique to operating a hydro system as large as the Federal Columbia River Power System (FCRPS). The variation in hydro generation due to the volume of water supply from one year to the next can be substantial. BPA also faces other operational risks and variability that increase BPA's risk exposure, including the following: (1) load variability due to changes in load growth and weather; (2) nuclear plant (CGS) generation; (3) wind generation and value of output; (4) transmission expenses; (5) IOU benefit levels; (6) DSI benefit levels; and (7) variability in electricity prices due to load, resource, and natural gas price variability. All these risk factors are quantified in the Risk Analysis Study. One major operational risk that is not quantified in this Risk Analysis Study is the potential impact of changes to the Biological Opinion. There is currently no specific guidance on what changes a remanded Bi-Op will involve so that BPA can incorporate the risk into the Initial Proposal. For additional information on how BPA intends to respond to Bi-Op uncertainty, *See,* Section 3 of this study.

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

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

The PNW and Federal hydro generation risk factors reflect the 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 this rate filing in RevSim in two ways. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A.

For FY 2007-2009, hydro generation risk was accounted for by inputting monthly hydro generation data estimated by the HydroSim Model for monthly streamflow patterns experienced from October 1928 through September 1978 (also referred to as the 50 water years). These monthly hydro generation data are developed by simulating hydro operations sequentially over all 600 months of the 50 water years. This analysis by HydroSim is referred to as a continuous study. *See,* Hydro-Regulation component of the Load Resource Study, WP-07-E-BPA-01 regarding HydroSim, continuous study, and 50 water years. Hydro generation adjustments were made to each year of the 50 water year data from the continuous study for FY 2007-2009 to reflect the refilling of non-treaty storage in Canada. Additional hydro generation adjustments were made to each of the 50 water year data from the continuous study for FY 2007 to reconcile differences between the HydroSim study for FY 2006 and the HydroSim study for FY 2007.

The PNW and Federal hydro generation data are used to estimate prices and revenues for 3,000 three-year simulations (FY 2007-2009). The monthly Federal hydro generation data are input into the RevSim Model to quantify the impact that Federal hydro generation variability has on BPA's net revenues. The associated monthly PNW hydro generation data are input into AURORA to quantify the impact that PNW hydro generation has on PNW electricity prices. Each simulation uses hydro generation from a stream flow pattern from the refill study for FY 2006 and a sequential set of three water years from the continuous study for FY 2007-2009.

The initial water year (FY 2007) of the sequential set of three water years is randomly sampled from 1929 through 1978. When the end of the 50 water years is reached (at the end of water year 1978), monthly hydro production data for water year 1929 is subsequently used. For example, if a simulation for FY 2007-2009 starts with water year 1977, the simulation uses water years 1977 through 1978, as well as water year 1929, for a total of three water years. This approach is used so that each of the 50 water years is sampled an equal number of times.

For FY 2007-2009, prices and net revenues are estimated based on each of the 50 water years being sampled 60 times to produce 3,000 three-year simulations. Using the hydro-regulation data for FY 2007-2009 in this continuous manner captures the dry, normal, and wet weather patterns inherent in the 50 water years and the impact these patterns have on electricity prices and BPA's net revenues over time. Using the hydro-regulation data from the refill study for FY 2006 provides more accurate data on current FY hydro generation risk by relying on updated information about reservoir levels and streamflow forecasts.

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 the 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

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

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

2.4.3 California Hydro Generation Risk Factor

This risk factor reflects the uncertainty that the timing and volume of stream flows 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. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A.

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

2.4.4 California Load Risk Factor

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

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

2.4.5 Natural Gas Price Risk Factor

This risk factor reflects the uncertainty in the costs of producing electricity from gas-fired resources throughout the WECC region. Natural gas price risk is simulated in the Natural Gas Price Risk Model and the associated spot market electricity prices are estimated in AURORA. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A and Market Price Forecast Study, WP-07-E-BPA-03.

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

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

2.4.6 Nuclear Plant Generation Risk Factor

This risk factor is modeled in the CGS Nuclear Plant Risk Model and reflects the uncertainty in the amount of energy generated by the Columbia Generating Station (CGS) nuclear plant. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A. Quantification of this risk is such that the average of the simulated outcomes is equal to the expected monthly CGS output specified in the Load Resource Study, WP-07-E-BPA-01**.** The potential values of the results simulated can vary from the output capacity of the plant to zero output.

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

2.4.7 IOU REP Settlement Benefits Risk Factor

This risk factor reflects the uncertainty in the amount of benefits from the IOU REP Settlement Agreement in FY 2008 and FY 2009, relative to the benefits included in the Revenue Requirement when setting rates. *See,* Revenue Requirement Study, WP-07-E-BPA-02**.** The quantification of this risk reflects the contract terms set forth in the IOU Residential Exchange Settlement Agreements entered into in May 25, 2004. *See,* Residential Exchange Program Settlement Agreements with Pacific Northwest Investor-Owned Utilities, Administrator's Record of Decision, signed October 4, 2000, as amended, Administrator's Record of Decision, signed May 25, 2004 (IOU Settlement ROD). In the IOU Settlement ROD, BPA agreed to provide 2200 aMW of financial benefits to the regions IOUs based on the difference between forward market electricity prices and the lowest cost flat PF rate with a maximum (capped) value of $300 million/year and a minimum (floor) value of $100 million/year. There will be no uncertainty in the amount of IOU REP Settlement benefits in FY 2007, relative to the benefits included in the Revenue Requirement when setting rates, since by the Final Rate Proposal the actual benefit payments for FY 2007 will be known. For FY 2008 and 2009, the forward market price risk for a 12-month strip of power was simulated by the Forward Market Price Risk Model and the lowest cost flat PF rates and IOU REP Settlement Benefits were estimated in the ToolKit Model, which are all components of the Risk Analysis Study. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A.

2.4.8 Direct Service Industry (DSI) Benefits Risk Factor

This risk factor reflects the uncertainty in the amount of DSI benefit payments in FY 2008 and FY 2009, relative to the benefits included in the Revenue Requirement when setting rates. *See,* Revenue Requirement Study, WP-07-E-BPA-02**.** The quantification of this risk reflects the service terms set forth in the BPA Service to DSI Customers for Fiscal Years 2007-2011, Administrator's Record of Decision, signed June 30, 2005, which includes providing 560 aMW of financial benefits based on the difference between forward-market electricity prices and the lowest-cost flat PF rate up to a maximum of $12.00/MWh or $58.9 million/year to the aluminum company DSIs, and an FPS sale of 17 aMW to the Port Townsend Paper Company via its local PUD at the lowest-cost flat PF rate. The forward-market price risk for a 12 month strip of power was simulated by the Forward Market Price Risk Model, the benefits paid to the aluminum smelters were computed in the DSI Benefit Risk Model, and the service to Port Townsend was modeled in RevSim, which are all components of the Risk Analysis Study. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A.

While the DSI contract terms have not been negotiated yet, it was assumed for the Initial Proposal that, similar to the IOU benefits, there is no uncertainty in the amount of DSI benefits paid to the DSIs in FY 2007, relative to the benefits included in the Revenue Requirement when setting rates. This assumption will be revisited and revised as needed for the Final Rate Proposal once the DSI contract terms have been negotiated.

2.4.9 Wind Resource Risk Factor

This risk factor, which is quantified in both risk simulation models and RevSim, reflects the uncertainty in the amount and value of the energy generated by BPA's portion of Condon, Klondike, Stateline, and Foote Creek I, II, and IV wind projects. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A. The wind generation risk is quantified in four risk simulation models (the Foote Creek projects are combined) such that the average of the simulated monthly generation outcomes for each wind project are equal to the expected monthly generation values included in the Load Resource Study, WP-07-E-BPA-01. The risk of the value of the wind generation is calculated in RevSim and is based on the difference between the purchase prices specified in output contracts and the prices received/paid for surplus energy sales/purchased power for the amount of variable energy produced, since BPA only pays for the amount of energy that is produced.

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

2.4.10 Transmission Expense Risk Factor

This risk factor reflects the uncertainty in PBL transmission and ancillary expenses, relative to the expected expenses included in the Revenue Requirement when proposing rates. *See,* Revenue Requirement Study, WP-07-E-BPA-02**.** 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 costs being asymmetrical, since it reflects how transmission and ancillary services expenses vary from the cost of the fixed, take-or-pay, firm transmission capacity that the PBL has under contract, which must be paid regardless of whether or not it is used. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A.

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

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

This risk factor is quantified in RevSim and reflects the uncertainty in the amount of 4(h)(10)(C) credits BPA is allowed to credit against its annual U.S. Treasury payments. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A. The 4(h)(10)(C) credit is the method by which BPA implements a provision in the 1980 Pacific Northwest Electric Power Planning and Conservation Act that allows BPA to be reimbursed for system-wide fish and wildlife expenditures it makes on behalf of the non-power purposes of the Federal hydro projects. BPA reduces its annual Treasury payment by the amount of the credit. The amount of the 4(h)(10)(C) credits that BPA can take for each of the 50 water years for FY 2007-2009 is determined by summing the costs of the operational impacts (power purchases) and the expenses and capital costs associated with BPA's fish and wildlife mitigation measures, and then multiplying the total cost by 0.223 (22.3 percent representing the non-power purpose percentage of the FCRPS). The direct program expenses and capital costs for FY 2007-2009 do not vary by water year and are documented in the Revenue Requirement Study, WP-07-E-BPA-02.

The costs of the operational impacts are calculated for each of the 50 water years in RiskMod for FY 2007-2009 by multiplying spot market electricity prices from AURORA by the amount of power purchases (aMW) that qualifies for 4(h)(10)(C) credits. The amounts of power purchases (aMW) that qualify for 4(h)(10)(C) credits are derived external to RevSim, but are used in RevSim to calculate the dollar amount of the 4(h)(10)(C) credits. A description of the methodology used to derive the amounts of power purchases (aMW) associated with the 4(h)(10)(C) credits is contained in the Load Resource Study Documentation, WP-07-E-BPA-01.

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

2.4.12 RevSim Analysis

The RevSim module within RiskMod serves two main functions in determining rates. The first function (the Fifty Water Year Run) is to calculate secondary energy revenues and 4(h)(10)(C) credits which are used by the RAM2007 model. The second function (the Risk Simulation Run) is to simulate PBL's operational net revenue risk. . *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A. Inputs to RevSim include risk data simulated by RiskSim and AURORA, along with deterministic monthly load and resource data, monthly PF rates, and non-varying revenues and expenses from the Load Resource Study, WP-07-E-BPA-01, the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-07-E-BPA-05, and the RAM2007.

The risk data simulated by RiskSim and monthly spot market electricity prices estimated by AURORA are used to calculate 3000 net revenues in RevSim for each fiscal year from FY 2007-2009. This process yields a total of 9,000 annual net revenues, which are provided to the ToolKit Model to calculate TPP. *See,* Section 3 of this Study, regarding the ToolKit Model.

2.4.13 Results from RiskMod

RiskMod results are used in an iterative process with the ToolKit Model and the RAM2007 to calculate PNRR and, ultimately, rates that provide BPA with a 92.6 percent TPP for the three-year rate period. The net revenues estimated for each RiskMod run depend on the level of the rates developed by the RAM2007 at different levels of PNRR. RiskMod estimates several temporary, intermediate sets of net revenues during the iterative process of trying to develop rates that yield a 92.6 percent TPP for the three-year rate period. The final set of net revenues from RiskMod is the set that yields a 92.6 percent TPP. .

The net revenue and forward market electricity price risks estimated by RiskMod are inputs into the ToolKit Model. The ToolKit Model uses the net revenue and forward market electricity price risks estimated by RiskMod, the net revenue risk estimated by the Non-Operating Risk Model (NORM) model, and additional adjustments to net revenues from interest earned on cash reserves, and CRACs to calculate IOU benefits, PNRR, and TPP. *See,* Sections 2-3 of this Study, regarding NORM and the ToolKit Model.

A statistical summary of the annual net revenues for FY 2007-2009 estimated by RiskMod using Proposed Rates with $96 million in PNRR is reported in Table 1. Net revenues over the rate period average $148.1 million/year. These values only represent the operational net revenues calculated in RiskMod. They do not reflect additional net revenue adjustments in the ToolKit Model, such as IOU benefits, the NORM output, interest earned on cash reserves, Cost Recovery Adjustment Clause (CRAC), and Dividend Distribution Clause (DDC). *See,* Sections 2-3 of this Study, regarding NORM and the ToolKit Model.

Table 3: RiskMod Net Revenue Statistics (With PNRR of $96 million)			
	FY 2007	FY 2008	FY 2009
Average	216,347	180,125	47,867
Median	185,647	161,110	26,168
Standard Deviation	371,585	298,035	301,326
1% <=	-441,154	-376,026	-507,465
2.5% <=	-379,325	-322,735	-439,190
5% <=	-341,977	-272,790	-397,495
10% <=	-245,477	-205,872	-343,487
15% <=	-163,600	-136,589	-282,918
20% <=	-95,925	-70,867	-211,295
25% <=	-35,389	-22,778	-152,298
30% <=	6,454	12,634	-108,414
35% <=	52,827	52,563	-71,328
40% <=	101,242	89,728	-38,026
45% <=	147,760	126,964	-6,684
50% <=	185,163	161,043	26,050
55% <=	222,039	195,961	64,121
60% <=	267,951	233,383	99,860
65% <=	315,533	274,118	138,359
70% <=	369,700	313,130	179,445
75% <=	428,762	358,468	223,758
80% <=	501,410	417,905	278,442
85% <=	581,682	480,809	343,608
90% <=	701,519	566,267	439,173
95% <=	881,296	706,323	566,205
97.5% <=	1,078,437	836,602	716,056
99% <=	1,252,221	1,028,338	898,243

2.5 Non-Operating Risk Model (NORM)

NORM is an analytical risk tool that was developed to capture risks other than operational risks in the rate setting process. It was first introduced as part of the May 2000 Power Rate Proposal . NORM models the non-operating risks of the generation function, as well as the risks of the Corporate costs that are covered by the generation function. Transmission function risks are not included in the analysis. In general, NORM includes the generation function expense uncertainty for transmission services. NORM does model some changes in revenue, and some changes in cash. Whereas RiskMod is used to quantify risks having to do with various economic and generation resource capability variations, NORM is used to model the impact on expected costs associated with risks surrounding projections of non-operations related revenue or expense levels associated with the generation function in the revenue requirement. The outputs from NORM, along with the output from RiskMod, are input into the ToolKit model to assess the TPP.

The previous version of NORM, introduced in the WP-02 rate case, modeled only changes in expenses. This current version models both the accrual and cash impacts of the included risks, and supplies 3000 games of both net revenue and cash impacts to the ToolKit.

2.5.1 Methodology

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

2.5.2 Data Gathering and Development of Probability Distributions

To obtain the data used to develop the probability distributions used by NORM, BPA interviewed the subject matter experts (SME) for each capital and expense item modeled. Prior to each interview, the SME was sent a set of questions to think about regarding the risks surrounding the cost estimates included in the final PFR. During each interview, the SME was 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 SME was able to provide a complete probability distribution. For the remaining cost items, BPA used the information provided to develop the probability distributions.

2.5.3 Inputs

2.5.3.1 CGS O&M

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

(1) Base O&M

(2) Nuclear fuel

(3) Decommissioning Trust Fund Contributions

(4) NEIL Insurance Premiums

(5) Capital

Energy Northwest (EN) is funding the capital additions for EN FY 2007- 2009 with bonds, with the bond interest and amortization included in CGS debt service. Except for a small amount of expense included in O&M during BPA's FY 2009 for capital additions that will be made in EN FY 2010, the uncertainty in CGS capital expenditures is reflected in CGS debt service, rather than in O&M.

For this rate case, NORM has captured the uncertainty around the Base O&M and NEIL insurance costs only. For Base O&M, NORM assumes that the most likely outcome is that EN will realize 2/3 of the cost reductions contained in the final PFR. The minimum value is the final PFR cost estimate, and the maximum value is the initial PFR estimate. For NEIL insurance, NORM has modeled the uncertainty around the level of the gross premium and the level of earnings on the NEIL fund. Member utilities receive annual distributions based on the level of these earnings, which lowers the premiums they actually pay.

The distributions for Total CGS O&M are shown graphically in Table 1 of the documentation. Distributions are shown for each fiscal year for FY 2007-2009, and also for the total of the 3 years. *See,* Risk Analysis Study Documentation WP-07-E-BPA-04A.

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

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

(1) Additional security costs if an event occurs

(2) Additional fish costs if an event occurs

(3) Additional system needs

(4) Additional extraordinary maintenance

(5) Base O&M for Reclamation only

Historically, Reclamation has under run 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 Final PFR value, and a maximum value equal to the Final PFR.

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

For Additional System Needs, NORM models the uncertainty that additional repair and maintenance costs may be incurred above those contained in the final PFR, and the probability that an outage event will occur.

The distributions for Total Corps and Reclamation O&M are shown graphically in Table 2 of the documentation. Distributions are shown for each fiscal year for FY 2007-2009, and also for the total of the 3 years. *See,* Risk Analysis Study Documentation WP-07-E-BPA-04A.

2.5.3.3 Colville/Spokane Settlement

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

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

The floor annual price is calculated as the FY 1995 floor price of 0.661414 mills/kWh escalated by the combined escalator for each fiscal year thereafter. Similarly, the ceiling annual price is the FY 1995 ceiling price (0.832892 mills/kWh) escalated by the combined escalator for each year thereafter. The combined escalator equals the simple average of the BPA price escalator and Consumer Price Index (CPI) escalator for the fiscal year. The CPI escalator is the ratio of the CPI for the September ending the previous fiscal year and the CPI for September 1995. To model the uncertainty around the CPI escalator, NORM uses a normal probability distribution (mean = 3 percent, standard deviation = 0.1 percent) around the CPI estimates for FY 2006-2008.

To model the variability around Grand Coulee generation, a mean and standard deviation was calculated for the 50 historic water years average annual output. The mean and standard deviation were used as parameters for a normal probability distribution, which was then truncated at the minimum and maximum values for the 50 historic years. The 50 years of data is provided in Table 13 of the documentation. *See,* Risk Analysis Study Documentation WP-07-E-BPA-04A.

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 Coulee. If the base payment exceeds the ceiling, the Colville payment equals the ceiling. If the base payment is below the floor, the payment is set equal to the floor, and the difference is carried forward as a loan to be paid off the following fiscal year. A new loan is created each year the base payment is below the floor, or the following year's base payment is insufficient to pay off the previous year's loan.

Currently, legislation to establish a similar settlement with the Spokane Tribe has yet to pass the Congress. However, BPA believes there is at least a 60 percent probability that the legislation will pass during FY 2006. Therefore, NORM assumes that 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 graphically in Table 3 of the documentation. Distributions are shown for each fiscal year for FY 2007-2009, and also for the total of the 3 years. Similar graphs for the Spokane Settlement payments are shown in Table 4 of the documentation. *See,* Risk Analysis Study Documentation WP-07-E-BPA-04A.

2.5.3.4 Public Residential Exchange

For the Public Residential Exchange, the SME provided the complete probability distribution. It is contained in Table 5 of the documentation. *See,* Risk Analysis Study Documentation WP-07-E-BPA-04A.

2.5.3.5 PBL Transmission Acquisition and Ancillary Services

For Transmission expense, NORM modeled uncertainty around:

(1) 3rd Party GTA wheeling
(2) 3rd Party Transmission and Ancillary Services
(3) Reserve and other Services

The uncertainty around PBL purchases of Transmission and ancillary services from TBL is modeled in RiskMod.

For 3rd Party GTA wheeling, NORM modeled the uncertainty around the level of future price increases for FY 2007-2009. For 3rd Party Transmission and Ancillary Services, NORM modeled the uncertainty around additional costs due to congestion (either additional fees imposed or having to find an alternate, more expensive path). For Reserve and other Services, NORM modeled the uncertainty around future TBL price increases for FY 2008-2009. The distributions for Total Transmission Services Expense modeled in NORM are shown graphically in Table 6 of the documentation. Distributions are shown for each fiscal year for FY 2007-2009, and also for the total of the 3 years *See,* Risk Analysis Study Documentation WP-07-E-BPA-04A.

2.5.3.6 PBL Internal Operations

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

(1) PBL System Operations
(2) PBL Scheduling
(3) PBL Marketing and Business Support
(4) Corporate G&A, including Shared Services and TBL Supply chain allocated to PBL
(5) Telemetering Equipment and Replacement

For Corporate G&A, NORM assumes the final PFR 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 first summed all the remaining cost estimates. A probability distribution was developed with a minimum that is 10 percent lower than the summed PFR values, and a maximum that is 10 percent higher.

The distributions for Total Internal Operations Cost, including Corporate G&A that are modeled in NORM are shown graphically in Table 7 of the documentation. Distributions are shown for each fiscal year for FY 2007-2009, and also for the total of the 3 years. *See,* Risk Analysis Study Documentation WP-07-E-BPA-04A.

2.5.3.7 Fish & Wildlife Expenses

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

(1) Direct program costs

(2) US F&W Lower Snake River Hatcheries

Graphs of the distributions for F&W Direct Program Expense, along with additional descriptive statistics, are shown in Table 8 of the documentation. Distributions are shown for each fiscal year for FY 2007-2009, and also for the total of the 3 years. Similar graphs for the Lower Snake Hatcheries expense are shown in Table 9. *See,* Risk Analysis Study Documentation WP-07-E-BPA-04A.

2.5.3.8 Capital Expenditures

For this rate case, NORM modeled uncertainty around the capital expenditures in the following areas:

(1) Conservation

(2) Direct Program F&W

(3) PBL Capital Equipment (including Corporate allocated to PBL)

(4) Corps/Reclamation Direct Funded Capital

(5) Columbia River Fish Mitigation (CRFM) plant in service

The uncertainty modeled relates to both the level of capital expenditures and the interest rate on the bonds or appropriations used to fund the investments. In addition, NORM modeled the uncertainty around the level of interest rates on the bonds used to fund CGS capital investments, and the amount of CRFM expenditures that will move into plant in service during the rate period.

2.5.3.9 Interest Rate Risk

For interest rate risk, NORM modeled uncertainty around the interest rates on the following:

(1) 30-Year Appropriations
(2) 30-Year U.S. Treasury Bonds
(3) 5-Year U.S. Treasury Bonds
(4) 10-Year Tax-Exempt Municipal Bonds

These were all modeled as discrete probability distributions. The full distributions are given in Table 10 and Table 11 of the documentation. *See,* Risk Analysis Study Documentation WP-07-E-BPA-04A.

2.5.3.10 Federal Depreciation, Amortization and Net Interest Distributions

Changes in the level of capital expenditures, the amount of plant put into service, and the interest rate on the debt that funded the capital, affect net revenues through changes in depreciation and amortization expense, and changes in net interest expense. The distributions for Total Federal depreciation, amortization, and net interest are shown graphically in Table 12 of the documentation. Distributions are shown for each fiscal year for FY 2007-2009, and also for the total of the 3 years. *See,* Risk Analysis Study Documentation WP-07-E-BPA-04A.

2.5.3.10.1 Conservation

To model uncertainty around the level of conservation capital expenditures, NORM uses the PFR final value of $32 million as the most likely value, with a minimum value of $13.5 million and a maximum value of $40 million. Interest rate risk is based on the uncertainty around the 5-Year U.S. Treasury bond rate.

2.5.3.10.2 F&W Direct Program

To model uncertainty around the level of direct program F&W capital expenditures, NORM uses the PFR Final value of $36 million as the maximum value, with a minimum value of $8 million and a most likely value of $27 million. Interest rate risk is based on the uncertainty around the 30-Year U.S. Treasury Bond rate.

2.5.3.10.3 PBL Capital Equipment

Capital equipment consists mostly of furniture and IT expenditures for PBL and corporate staff. To model the uncertainty around the level of capital expenditures, NORM uses the PFR final value as the mean of a normal distribution, with a standard deviation of $1 million. Interest rate risk is based on the uncertainty around the 30-Year U.S. Treasury bond rate.

2.5.3.10.4 Corps/Reclamation Direct Funded Capital

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

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

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

For the level of expenditure each year, NORM models uncertainty around the level of base investment and emergency capital needs. The incremental investment levels are then prorated across the remaining years of the rate period to determine the incremental amounts of plant put into service each year.

2.5.3.10.5 CRFM

The CRFM project is funded by appropriations received by the COE. The power portion of the investment becomes BPA's obligation to repay to the U.S. Treasury at the time the investment is placed into service in the accounting records. NORM models uncertainty around the amount of plant that will be placed in service during the rate period and the associated interest rate. During the PFR process, three alternate scenarios were developed around levels of CRFM expenditures that would be placed in service during the rate period. NORM has assigned a probability to each of these scenarios. Interest rate risk is based on the uncertainty around the 30-Year Appropriations rate.

2.5.3.11 Accrual to Cash (ATC)

Because not all changes in expense result in a similar change in cash, ATC is being modeled probabilistically in NORM for this rate case. NORM uses the deterministic ATC Table (Table 4 in this section) as its starting point, but replaces the deterministic value for the new value for each game for the following line items in the table:

(1) Line 1: Depreciation/Amortization

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

(3) Line 6: EN Debt Service included in income statement

In addition, NORM is modeling uncertainty around the continuation of the debt optimization program. For this rate case, NORM is assuming a 25 percent probability that debt optimization will not occur, and a 75 percent probability that PBL reserves will be higher due to debt optimization. The higher reserve levels result from net billing ending earlier under debt optimization, allowing revenues from net-billed customers to go to BPA rather than EN. NORM replaces the deterministic value with the new value for each game for the following line items:

(1) Line 3: EN Net Billing Prepaid Expense

(2) Line 4: September Revenue Lag included in All Other

(3) Line 7: Current Estimated EN Debt Service

(4) Line 8: Planned Advance Amortization of Federal Debt

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 4 below and assigns to each a distribution. It then runs 3000 games and feeds the results of these games into the ToolKit model. The ToolKit also accepts as input 3000 net revenue scenarios from RiskMod. The 3000 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.

Table 4
TOOLKIT NET REVENUE ACCRUAL-TO-CASH ADJUSTMENTS
(in $Millions)

		FY 2005	FY 2006	FY 2007	FY 2008	FY 2009
1	Depreciation/Amortization	$177.667	$184.677	$186.671	$192.838	$199.779
2	Interest Adjustments	($45.324)	($45.324)	($45.324)	($45.324)	($45.752)
3	ENW Net Billing Prepaid Expense	($0.927)	($7.244)	($29.965)	$0.654	($0.159)
4	All Other	($116.277)	($23.429)	$39.854	$2.190	($9.659)
5	**Sub total lines 1 — 4**	**$15.139**	**$108.680**	**$151.236**	**$150.358**	**$144.209**
6	Add: ENW Debt Service in Income Stmt.	$505.215	$539.804	$575.976	$567.590	$579.080
7	Less: Current Estimated ENW Debt Service (PBL only)	($238.443)	($347.686)	($575.976)	($567.590)	($579.080)
8	Less: Planned Advanced Amortization of Federal Debt	($313.403)	($337.200)	$0.000	$0.000	$0.000
9	**Sub total lines 6 — 8**	**($46.631)**	**($145.082)**	**$0.000**	**$0.000**	**$0.000**
10	Less: Scheduled Federal Debt Amortization	($148.097)	($128.476)	($170.273)	($185.211)	($176.447)
11	Less: Revenue Financed Capital Investments	$0.000	$0.000	$0.000	$0.000	$0.000
12	**Sub total lines 10 — 11**	**($148.097)**	**($128.476)**	**($170.273)**	**($185.211)**	**($176.447)**
13	**Accrual to Cash Adjustment (Lines 5 + 9 +12 – 16 (for 05 & 06 only))**	**($179.589)**	**($160.631)**	**($19.037)**	**($34.853)**	**($32.238)**
14	**IOU Deferral Payments not in line 13 computation**	**$0.000**	**($4.247)**	**Included in ATC adjustment above**		

2.6 Output

The output 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 3000 games. The ToolKit uses this file in its calculation of TPP.

3. RISK MITIGATION

3.1 Treasury Payment Probability (TPP)

BPA's risk mitigation goal is to meet BPA's TPP standard. As described elsewhere, this standard for a three-year rate period is 92.6% for the risks, financial reserves, and tools attributed to the PBL.

The Treasury Payment Probability, or TPP, is the probability that a business line will have sufficient financial reserves to cover all of the financial obligations to the Treasury that have been assigned to it during the course of a rate period, given the risks identified in Risk Analysis Model (RiskMod) and NORM, and the risk mitigation tools. BPA's 10-Year Financial Plan, adopted in 1993 and still in effect, calls for BPA to set rates to achieve a 95% TPP in each two-year rate period. Since FY 2002, the transmission and generation functions have their set rates separately, and BPA has determined that if each function separately meets the TPP standard with their respective rates and the reserves attributed to that business line, the Agency TPP requirement will have been met. BPA has calculated that a 92.6% TPP for a three-year rate period is equivalent to the two-year 95% TPP called for in the 10-Year Financial Plan.

3.2 ToolKit Overview

The ToolKit is an Excel 2003® spreadsheet that used to evaluate PBL's 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 its main page (the main worksheet). It reads in data from two external files, one each from RiskMod and NORM. Most of the logic for simulating the financial results in the years included in a ToolKit analysis is in VBA code (Microsoft's ***V***isual ***B***asic for ***A***pplications). This code contains comments that document how the code works, and is a useful reference for how the ToolKit works.

More specifically, the ToolKit is used to assess the effects of various policies, assumptions, changes in data, and risk mitigation measures on the level of year-end reserves attributable to generation. It registers a deferral of a Treasury payment when these reserves fall below the level of "Liquidity Reserves" entered on the main page of the ToolKit. The amount of liquidity that BPA has determined need to be supplied by financial reserves is $50 million. The ToolKit is run for 3000 "games" or iterations. The number of those games where each of the three years in the rate period ends with at least $50 million in PBL reserves is divided by 3000 to calculate the TPP.

Most of the modeling of risks is performed by RiskMod and NORM, documented elsewhere in this Study. The ToolKit reads in distributions of values from files created by RiskMod and NORM and calculates the TPP and other risk statistics and reports results, and allows analysts do calculate how much PNRR needs to be added, if any, to meet the TPP standard.

3.3 Tools Modeled in the ToolKit

Risk mitigation is a very important part of this rate proposal. The preceding sections of this chapter have described the risks that BPA is explicitly modeling. This section describes the tools for mitigating those risks that BPA has considered. Some of these tools have been modeled and included in BPA's rate proposal; others have been considered but not modeled; another has not been modeled but in included (the NFB Adjustment). These are described below.

3.3.1 Tools Incorporated into BPA's Proposal

3.3.2 Reserves and PNRR

3.3.2.1.1 Reserves

The fundamental protection against the financial impacts of the risks BPA faces is its financial reserves. For this power function rate case, it is the reserves attributable to the generation function (PBL reserves), with one exception described below in more detail, that are considered. Financial reserves comprise cash held by the U.S. Treasury in the Bonneville Fund plus amounts of deferred borrowing. Deferred borrowing refers to amounts of capital expenditures that BPA has made that authorize borrowing from the Treasury when BPA has not yet completed the borrowing. Deferred borrowing amounts can be converted to cash by completing the borrowing.

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

3.3.2.1.2 PNRR

BPA conducts analyses of its TPP with the projections of PBL reserves in its rate cases. If the TPP is below the standard established in the 10-Year Financial Plan, as translated for the number of years in the rate period, this indicates that the projected reserves, along with whatever other risk mitigations are being considered in the analysis, are not sufficient to reach the TPP standard. This is typically corrected by calculating an amount of Planned Net Revenues for Risk (PNRR) that will be added 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 PBL reserves, and increase TPP.

Compared to most of the expenses in the revenue requirement, PNRR is an unusual cost. For one thing, there is no expectation of disbursing cash. 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 counterparty fees in one way or another that it would not get back – there would be a long-term net cost. For another, including PNRR in one rate case is likely to reduce the need for PNRR or other forms of risk mitigation in subsequent rate cases. If it turns out that the reserves generated by the rate increase PNRR causes are not drawn down to pay bills in the rate period under consideration, they remain available in later rate periods and will serve to reduce the cost of risk mitigation that customers will pay for then.

3.3.2.1.3 Other Agency Reserves Temporarily Available to PBL

Management has directed staff to make study whether any agency reserves not attributed to generation could be considered during the process of setting power rates to be available for helping to mitigate power risks. Staff has concluded that there are such reserves. When TBL completed its rate case for FY 2006-2007, its rates passed BPA's three tests: 1) they demonstrated cost recovery on an accrual basis; 2) they demonstrated cost recovery on a cash basis, and 3) they satisfied the requirement of the 10-Year Financial Plan that the TPP be at least 95% for a two-year rate period. In fact, the TBL TPP was higher than 95%: TBL's reserves were actually greater than needed to support the 95% TPP standard. TBL has not set rates for FY 2008 or 2009, so it is not possible to determine whether the projections of TBL reserves for those years are greater than needed to support the TPP standard. However, staff has concluded that if TBL reserves were smaller than projected by $55 million in FY 2007, TBL's rates would still meet the TPP standard. Therefore, staff has concluded that $55 million of reserves not attributed to PBL in FY 2007 can be considered to be available for mitigating PBL risks. Since TBL risk requirements for FY 2008 and 2009 cannot be known at this time, the $55 million of reserves is only available to PBL in FY 2007. PBL will plan that any temporary use of these reserves in FY 2007 would be completely made up for in such a way that TBL rates would be no higher than if BPA had not made this assumption. To assume that these reserves can be available to PBL in years other than FY 2007 would allow for the unacceptable possibility that TBL customers could be subsidizing PBL rates. *See,* Leathley, *et al.,* WP-07-E-BPA-08.

3.3.2.2 The Cost Recovery Adjustment Clause (CRAC)

Cost-recovery adjustment clauses, or CRACs, can be very powerful risk mitigation tools. BPA proposed a single CRAC in its May 2000 power rate case, and the Supplemental Proposal, a result of highly effective collaboration between BPA and its power customers, included three distinct CRACs. The Load-Based (LB) CRAC dealt with the financial uncertainty of the augmentation solution, the Financial-Based (FB) CRAC mitigated general financial risks, and the Safety Net (SN) CRAC served as a back-stop against financial risks that could not be handled by the first two CRACs. In this rate case, BPA is returning to a single CRAC.

As BPA has generally employed them, CRACs or Interim Rate Adjustments (IRAs) are rate adjustment mechanisms that respond to the financial risks BPA faces. The metric used for determining whether this mechanism has triggered was originally financial reserves, but BPA decided in the May 2000 Proposal to use accumulated net revenues because net revenues are a more standard financial metric.

3.3.2.2.1 Basic Description of the Proposed CRAC

The CRAC proposed by BPA is generally similar to the SN CRAC and FB CRAC from the SN-03 rate case, though there are some differences that will be noted. It is a one-year upward adjustment in the HLH and LLH energy charges for rates subject to the CRAC. The annual collection amount is limited to $300 million. The threshold is an amount of AMNR for PBL as accumulated since the end of FY 1999. The AMNR threshold values have been calibrated to be equivalent to PBL financial reserve levels of $470 million for the FY 2007 CRAC and $500 million for the FY 2008 and FY 2009 CRACs.

The CRAC (and NFB Adjustment and DDC) calculations will be made shortly before the beginning of each year in the rate period. A forecast of the AMNR at the end of the year will be made, and this will be compared to the thresholds for the CRAC and the DDC. If this forecast is below the CRAC threshold, a rate adjustment will be calculated for the duration of the upcoming fiscal year; if the forecast is above the threshold for the DDC, a separate downward rate adjustment will be calculated to distribute dividends to covered rates for the duration of the upcoming fiscal year.

3.3.2.2.2 Differences from the FB CRAC

There are four main differences between the design of the current FB CRAC and that of the proposed CRAC:

1. The proposed CRAC applies only to energy rates, not to demand and load variance;
2. The proposed CRAC revenue collection amounts will not be prorated to account for Slice load;
3. The proposed CRAC does not have a true-up feature; and
4. The caps for the proposed CRAC can be adjusted by the NFB Adjustment described below.

FB CRAC and the proposed CRAC use AMNR thresholds and annual caps, although the thresholds and caps are different. The caps for the FB CRAC ranged from $125 million in FY 2002 to $175 million in FY 2006. The proposed CRAC has annual caps of $300 million in each year in the rate period.

3.3.2.2.3 Differences from the SN CRAC

There are three main differences between the design of the current SN CRAC and that of the proposed CRAC:

1. The proposed CRAC applies only to energy rates, not to demand and load variance;
2. The proposed CRAC does not have limits on certain categories of costs to prevent cost increases in those categories from increasing the CRAC percentage; and

3. The caps for the proposed CRAC can be adjusted by the NFB Adjustment described below.

The SN CRAC and the proposed CRAC also use AMNR thresholds and annual caps, though the thresholds and caps are also different. The caps for the SN CRAC were $290 million per year; the proposed CRAC has annual caps of $300 million in each year in the rate period.

3.3.2.3 DDC

tone of the financial policy objectives for this rate case was to ensure that PBL reserves did not accumulate to excessive levels. A mechanism used in the WP-02 rate case to guard against this possibility was the Dividend Distribution Clause, or DDC. The DDC is triggered if AMNR is above (instead of below) a threshold, and if so. There is a downward adjustment to rates. In the same way that a CRAC passes bad financial luck to BPA's customers, a DDC passes good financial luck to BPA's customers.

3.3.2.3.1 Differences from the Current DDC

There are two main differences between the design of the current DDC and that of the proposed DDC:

1. The proposed DDC applies only to energy rates, not to demand and load variance; and
2. The proposed DDC is capped, and will not reduce the average annual LLH energy rate to less than $1 per MWh.

Both DDCs use AMNR thresholds, though the thresholds are different. The WP-02 DDC thresholds, measured in AMNR, is designed to trigger at the equivalent of $1,700 million in PBL reserves for FY 2002, declining over time to $1,200 million for FY 2006; the proposed DDC has

AMNR thresholds designed to trigger at the equivalent of $800 million in PBL reserves for each of the three years.

3.3.3 Tools Not Incorporated into BPA's Proposal

3.3.3.1 Secondary Revenue Rebate Mechanism

The most significant financial risk or uncertainty BPA faces is the variability of its secondary revenues. The fuel for the Federal hydro system – water in the Columbia River system passing through Federal dams – is highly variable. In assessing whether it is in load-resource balance, BPA counts on a quantity of this hydro fuel roughly equal to the lowest flow observed in the 50-year period from 1929 through 1978 ("critical water"), but recognizing that the supply of hydro fuel is almost always greater than this, it credits the revenue requirement for the probable realization of some secondary sales. This credit has usually been given by calculating the expected value of the net revenue from these secondary sales and purchases, and crediting this against the costs in the revenue requirement that is the basis for calculating rates. This reduces the rates that PBL customers pay, (except Slice purchasers) but leaves the BPA system exposed to the risk that net secondary revenues will be less than that expected value. Risk mitigation, such as CRACs or PNRR, has generally been needed to ensure adequate assurance of being able to repay U.S. Treasury in lean years.

An alternative is to credit less than the whole expected value of net secondary revenues against expenses in the rate calculation, and then to rebate to power customers the actual financial benefit of secondary revenues above the amount credited. Since there would be a smaller credit for secondary revenues, the posted rates would be higher in this design. As net secondary revenues materialize, they would be rebated to power customers, resulting in rates on average of the same level – except for the costs of risk mitigation. Since BPA would not be required to maintain other risk mitigation tools sufficient to get through a dry year(s) until additional revenues can be received, rates could be reduced to reflect the reduced reserve requirements. The average level of PBL reserves under this design would be lower than under the traditional design, and the average “effective” rate level, that is, after reflecting the effects of any CRACs, DDCs, or rebates, would also be lower.

3.4 Tools Not Modeled in the ToolKit

3.4.1 Tools Incorporated into BPA’s Proposal

3.4.1.1 National Marine Fisheries Service Federal Columbia River Power System Biological Opinion Adjustment

Fish recovery is an extremely important objective for BPA. Because of pending litigation over BPA’s fish and wildlife obligations, it is very difficult to determine what measures are required to accomplish this, let alone to determine their costs. In the May 2000 Proposal, the uncertainty over the financial impacts of future fish measures was reflected by the creation of a set of 13 distinct alternatives for fish and wildlife . No such set of alternatives exists for the FY 2007 to 2009 period. Today, BPA faces uncertainty about what kind of program will be required by either a new BiOp or a court ordered program. The possibilities are many and mostly unknowable, and probabilities cannot be estimated for any particular scenario that might be created. Because the uncertainty is so open-ended, BPA believes it is necessary to have an equally open-ended adjustment mechanism to ensure that the many programs of BPA and the FCRPS can continue to be funded no matter what fish and wildlife program BPA is obligated to implement.

The NFB adjustment is designed to protect the financial viability of the BPA system and its resources from the potentially large impact of court-ordered changes in the operation of the Columbia River hydro system and from fish and wildlife program costs. The NFB Adjustment results in an upward adjustment to the CRAC Maximum Recovery Amount (Cap) for any year in the rate period if unfore*See,*n fish and wildlife costs in the previous year arise from a predetermined set of circumstances. The NFB Adjustment calculation will result in an increase in the annual CRAC maximum recovery amount defined in Table A for the next fiscal year following the year in which the increased financial impacts are experienced. The NFB Adjustment is applicable to FY 2007 – 2009 based on changes in net revenue for FY 2006-2008.

The NFB Adjustment will "trigger" if changes to the anadromous fish portion of the Fish and Wildlife program caused by changes in FCRPS Endangered Species Act (ESA) compliance as required by a court order (including court-approved agreements), an agreement related to current litigation, a new NMFS FCRPS BiOp, or Recovery Plans under the ESA decrease PBL's net revenue. Net revenue impacts include foregone revenue, power purchases, direct program expense, fish credits, COE and Reclamation O&M, and capital repayment. Financial impacts will be calculated net of 4(h)(10)(C) credits. The triggering events, such as court orders, may occur at any time during a fiscal year. The assessment of the financial impacts of any such events will take place shortly before the end of the fiscal year in which the changes take effect.

While the NFB adjustment increases the *cap* on the amount the CRAC can collect; it does not necessarily increase the *amount* collected. If the NFB Adjustment triggers but AMNR is above the threshold, there will be no CRAC adjustment. On the other hand, if AMNR is below the threshold, the NFB Adjustment will allow BPA to recover more than the $300 million cap if such amounts are needed.

There can be multiple triggering events that are included in the analysis of financial impacts even though there is only one final analysis per year of the total financial impacts due to triggering events. For example, there could be more than one covered court order in FY 2007 that increases the financial impacts of operations in FY 2007. Both of these triggering events could be included in the calculation of the single NFB adjustment that would increase the cap on the CRAC collection during FY 2008. In addition, there could be a single NFB Adjustment for each year, FY 2007-2009 in the rate period.

Each NFB Adjustment affects only one year. However, since the comparison used to calculate the NFB adjustment is the actual operation for fish against the operation assumed in the rate case, it is possible for a decision to affect operations for more than one year of the rate period. For example, a decision in FY 2006 may affect operations in FY 2007 and FY 2008. There would be separate analyses of the total financial impact during FY 2006 for adjusting the cap on the CRAC applying to FY 2007 and of the total financial impact during FY 2007 for adjusting the cap on the CRAC applying to FY 2008.

Increases in the financial impacts during FY 2009 are not covered by the NFB adjustment proposed in this rate case, since the effect of incorporating those increases would need to be collected during FY 2010, and the rates for FY 2010 are not covered by this rate case.

3.4.1.2 Ability to Begin New 7(i) Proceeding

Prior to BPA's 2002 rate case, customers had been given a "rate lock" in their subscription contracts which prevented BPA from modifying the base rates it charged for power. When the May 2000 Proposal (covering the FY 2002-2006 period) had to be withdrawn from FERC's consideration as the West Coast power crisis and the attendant BPA augmentation crisis grew, concern over worst-case outcomes led to the development by PBL and its customers of a three-CRAC system. The Safety-Net CRAC was at that time merely a provision in the GRSPs that allowed BPA to implement a Safety-Net CRAC under specified, dire circumstances. Customers do not have a comparable rate lock governing BPA's power rates during the FY 2007-2009 period. Therefore, BPA has the right to begin another 7(i) rate proceeding prior to the expiration of the FY 2007-2009 rates. This right is comparable to the capability provided by the Safety-Net CRAC provisions of the Supplemental Proposal GRSPs. The SN CRAC proceeding permitted by the Supplemental Proposal GRSPs was described as "expedited"; while BPA would certainly do everything it could to ensure that a new rate proceeding initiated prior to the regular 7(i) process for the FY 2010-2011 period, presumably required due to emergency conditions, would expeditious, there are no special provisions to speed up that process.

3.4.2 Tools Not Incorporated into BPA's Proposal

3.4.2.1 Mid-Year Hydro Surcharge

Representatives of many of BPA's power customers have suggested to BPA that it implement a mid-year hydro surcharge. This proposal called for making an estimate of the amount of net secondary revenue PBL would receive about mid-way through a fiscal year, based on the actual net secondary revenue received and forecasts of the net secondary revenue to be received during the remainder of the fiscal year. Based on this forecast, a surcharge could be applied to BPA's power rates starting April 1 and continuing through the following March 31. BPA has met with customer representatives to discuss this idea several times, and have worked out some of the details that would be necessary to define in a rate proposal, but many needed details remain to be developed, such as how the surcharge would interact with computation of IOU REP Settlement benefits.

A problem this proposal faces is that a large proportion of BPA's power bills for the April through September period are subject to the provisions of net billing, and the cash payments made by customers for these bills would be sent to Energy Northwest until net billing obligations have been satisfied. This substantially thwarts the purpose of having the surcharge start in the middle of a fiscal year – getting additional cash to BPA as soon as possible to help make BPA's

U.S. Treasury payments. Many ideas have been suggested by customer representative and others for ways to ameliorate this problem, but no effective remedies have been created yet.

The complexities of the possible but not yet reliable solutions to the timing problem and the need to work out a large number of additional details (such as how the mid-year forecast would be made or how and when it might be adjusted with updated information) have prevented BPA from including this in its initial proposal, but BPA has not ruled it out for consideration in the final rate proposal, nor have they ended BPA's interest in this idea. BPA is committed to working with customers to analyze the potential of this proposal after BPA publishes its initial proposal. BPA will make every effort to make its TPP modeling tools, especially the ToolKit and RiskMod, able to calculate the benefits of mid-year hydro surcharges, including the assistance of other measures, such as "liquidity tools." If a mid-year hydro surcharge can be shown to be a significant risk-mitigation tool, and it is proposed by one or more parties in their direct case(s) in the FY 2007 rate proceeding, BPA will give it full consideration.

3.4.2.2 End-of-Year Hydro Surcharge

An idea similar to the mid-year hydro surcharge that has received only preliminary attention to date is a hydro surcharge calculated near the end of a BPA fiscal year. One aim of the mid-year hydro surcharge is to start additional cash flowing to BPA to mitigate the effects of a very lean year (i.e., low water, or low prices, or both). This might allow for additional revenue to flow to BPA for a lean FY 2007 as early as April of FY 2007. As noted above, translating the early flow of revenue into early flow of available cash has been found to be quite difficult.

An alternative would be to calculate the hydro surcharge near the end of a BPA fiscal year. This would allow for mitigation of the risk of a lean FY 2006 year. This is a significant benefit. The possibility of low net secondary revenues in FY 2006 is captured in BPA's risk modeling, but a mid-year hydro surcharge would not be of any benefit in mitigating this FY 2006 risk. An end-of-year hydro surcharge could be designed to generate additional revenue during FY 2007 if FY 2006 net secondary revenues are low, additional revenue during FY 2008 if FY 2007 net secondary revenues are low, etc. Several complexities of a mid-year hydro surcharge could be avoided in this mechanism: the very significant uncertainty about the net secondary revenues still present by March could be sidestepped; issues about how to design a true-up to accommodate the inevitable difference between a March forecast of fiscal year net secondary revenues and the final accounting of such revenues could be bypassed, and the obstacles to prompt BPA collection of cash posed by the net billing agreements would be circumvented.

3.4.2.3 Liquidity Tools

Several different "liquidity tools" have been suggested by BPA and its customers that may be useful in reducing the cost of risk mitigation. These tools are not included in BPA's initial proposal because they are still works in progress. However, should any of them be developed to the point of becoming reliable sources of liquidity that could be useful in mitigating financial risk and helping PBL meet its TPP standard, BPA may adopt them, and the impact of the selected tools would be included their effect in the final rates proposal. *See,* Leathley, *et al*., WP-07-E-BPA-08.

3.4.2.3.1 Direct Pay of EN Budget

Many of BPA's public customers are participants in the net billing agreements. These agreements were developed as a way to enter into long-term agreements that were not subject to annual appropriations before BPA became self-financed. The net billing agreements direct customers to remit their payments for BPA power deliveries to EN rather than to BPA, a concept referred to "net billing" because the customers receive monetary credits to their power bills from BPA. The net billing period starts with the bills for May power deliveries, and ensures that EN will have the money it needs at the beginning of its fiscal year (July). This arrangement results in EN's receiving somewhat more cash than it needs early in its fiscal year. This surplus is often as large as a couple hundred million dollars by September 30 when BPA needs to make its year-end payment to the Treasury. If BPA can work out a mutually satisfactory agreement with EN to pay EN as much as it needs each month consistent with the provisions of net billing agreements, net billing will not be necessary and customer payments can be made to BPA rather than EN, thus resulting in BPA's having more cash on hand at the end of its fiscal year. This should increase the level of reserves available to mitigate hydro and market price risk, which will boost TPP, having the net result of reducing the cost of other risk mitigation measures needed to meet the TPP standard. However, two cautions are warranted. This would cause major changes in BPA's typical pattern of reserve balances throughout BPA's fiscal year; BPA needs time to analyze the repercussions of this for its liquidity risks in all parts of its fiscal year to determine the extent to which the benefits at the end of the BPA fiscal year are offset by increased liquidity risk at other times in the year. The second caution is that BPA and EN must receive a private letter tax ruling from the IRS that the proposed arrangement would not adversely affect the tax-exempt status of any EN bonds. BPA and EN have requested such a ruling from the IRS. If BPA receives a favorable ruling by about May 1, it will be able to work with EN to develop a budget for EN's fiscal year 2007 reflecting this, and will incorporate the risk-reduction benefits in BPA's final rate proposal. If BPA receives an unfavorable ruling by about May 1, there will be no net benefit to the plan, and it will be dropped. If BPA does not receive a ruling by about May 1, there may be some options that can be built into the rate design and/or risk mitigation that will allow the capturing of some of the benefits of the plan at some point during the rate period. No action by customers is required.

3.4.2.3.2 Additional Liquidity Tools from U.S. Treasury

BPA is discussing with the U.S. Treasury the possibility of new agreements for liquidity tools through U.S. Treasury. If BPA and U.S. Treasury reach agreement, the risk-reduction benefits of these tools would be included in BPA's final rate proposal. No action by customers is required.

3.4.2.3.3 Changing the EN Contract Year

Customers have suggested changing the start of EN's contract year from July 1 to January 1. This would require getting all 111 net billing participants to amend all 300+ net billing agreements. There has not yet been a rigorous analysis of the cash-flow and risk implications of this change. It would not make sense to make this change and also move to direct pay of EN's budget. Customers would need to get these amendments before BPA would consider this option.

3.4.2.3.4 Customer Pre-payment of Bills

Customers have suggested that some or many of them would be willing to pre-pay three to six months of their power bills in order to accelerate BPA's receipt of the cash so as to increase TPP and reduce the cost of other risk mitigation. Certain Customers would have to agree to this before BPA would entertain proposing this change.

3.4.2.3.5 Deferral of IOU REP Settlement Benefits

Another suggestion that could increase BPA's liquidity in the first few months of its fiscal year is to defer the payments BPA plans to make to the IOUs as part of the IOU REP Settlement. The annual total of the payments will range from a contractual minimum of $100 million to a contractual maximum of $300 million. In addition, the $23 million per year repayment of benefits deferred from the current rate period might be covered by this arrangement. The monthly payments, then, would range from a minimum of $123 million / 12 = $10.25 million up to a maximum of $323 million / 12 = $26.92 million. If this plan were implemented, BPA would be able to count on additional liquidity in October of over $10 million, in November of over $20 million, and in December of over $30 million. Beyond that, depending on market price forecasts for the FY 2007 – 2009 period, BPA might be able to gain over $26 million of additional liquidity in October, over $53 million in November, and over $80 million in December. This plan would require 1) that BPA's public customers satisfactorily assure the IOUs that no litigation over the FY 2007 – 2009 IOU REP Settlement benefits will be forthcoming, and 2) that all current litigation related to REP benefits be settled prior to May 2006. Customers would need to effect this change.

3.4.2.3.6 Shifting BPA's June Billing Date to May

Customers have suggested that BPA change its date for billing for May power deliveries from early June to late May, since the net billing agreements identify the bills that are subject to net billing by the month in which BPA bills its customers. Their hope was that this would reduce the amount of cash above EN's needs that it would have received through net billing by September 30. BPA does not believe this concept has a significant potential to reduce the costs of risk mitigation.

3.4.2.3.7 Delaying Advance Amortization Payments to U.S. Treasury until December

Under Debt Optimization (DO), BPA reduces its payments for some EN debt and balances this with increased payments to U.S. Treasury, called advance amortization payments. These payments have been made by September 30. BPA has formed a team to study whether these advance amortization payments could be deferred until December in the event BPA needs additional liquidity early in its fiscal year. Until the consequences of this can be analyzed, the value of this potential tool cannot be known. Since BPA believes it is not prudent to count on DO for any particular year until it has received reliable word from the EN that it will approve

DO for that year, it is unclear to which BPA fiscal years PBL might be able to apply this tool in its rate case.

3.5 ToolKit Modification/Changes in TPP Modeling

Rates in the FY 2007 -2009 period will be different from those in the period covered by the SN-03 rate case (the SN CRAC rate case) for several reasons, and these changes need to be reflected in BPA's TPP calculations, and the tools used to perform those calculations. The CRAC BPA is proposing differs from the three CRACs that were adopted in the SN-03 rate case. BPA is modeling deferrals of U.S. Treasury payments slightly differently than in the SN-03 rate case. BPA is not proposing to change the amount of reserves set aside for liquidity, but the current version of the ToolKit allows for modeling such a change. The feature allowing the ToolKit to model PNRR amounts that are not the same for all years in a rate period has had to be disabled in order to calculate a more accurate PF rate and maximize the congruence between how rates are calculated in the Rates Analysis Model and how this is simulated in the ToolKit. These and other changes are described below.

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

BPA's initial rate proposal includes a cost-recovery adjustment clause (a CRAC), but the three specific CRACs from the SN-03 rate case will no longer be part of BPA's rates. The ToolKit has been changed to reflect this. In addition, there are features of the ToolKit that were added during the deliberations leading to BPA's SN-03 proposal that were not incorporated into BPA's SN-03 proposal. These features, a 'deadband' around the threshold for the SN CRAC and a 'slope' modifying the relationship between a $1 change in AMNR and the SN CRAC amount, have been removed from the ToolKit. These features were documented in the SN-03 version of the ToolKit.

3.5.2 Credit for Operating and Regulating Reserves

Another change in BPA's TPP modeling is that BPA is proposing a credit for operating and regulating reserves for customers who do not purchase those services from BPA's transmission arm but instead purchase them from third parties or self-supply. This credit needs to be modeled in the TPP calculations because the BPA rate used in the IOU REP Settlement benefit calculations is reduced by this credit before computing the IOU REP Settlement benefits. The credit is $0.89/MWh, and is input into the ToolKit on the "IOU_Data" worksheet.

3.5.3 Incorporating the IOU REP Settlement Benefits

One of the most significant developments, in terms of the number of adjustments that have to be made, since the last power rate case is the IOU REP Settlement defining the benefits to be paid to the IOUs for the next rate period. Under the IOU REP Settlement benefits the IOUs will receive benefits based on the difference between an estimate of the future market price and BPA's lowest-cost PF rate as adjusted (by a CRAC or a DDC). The IOU benefits are also an expense that must be recovered by rates, so there is a feedback loop that must be modeled. After preliminary rates are calculated in RAM2007, there are five possible adjustments to the IOU REP Settlement benefits which would also affect the PBL net revenues and the TPP: 1) changes in PNRR; 2) updates in the forecasted forward-block market price for FY 2008 and FY 2009; 3) a possible CRAC; 4) a possible DDC; and 5) a possible secondary revenue rebate. Because the ToolKit is where BPA models changes in PNRR and CRAC/DDC, and the market changes occur later in the simulated sequence of events than the changes in PNRR, the market changes are also modeled in the ToolKit.

3.5.3.1 PNRR

The interaction between PNRR and the IOU REP Settlement benefits is complex, and involves several different computer models. The goal for the ToolKit modeling is to approximate the treatment of PNRR by other models so that the ToolKit calculations of the impact of changes in PNRR in the ToolKit match the impact of the same increment of PNRR as it propagates through the other models.

After an amount of PNRR has been calculated by the ToolKit, the next step in the full iteration is to change the PNRR in the revenue requirement. This change is computed so as to result in a change in *net revenue* of the amount specified as the desired change in PNRR. As the PNRR amount in the revenue requirement is increased, the expected value of PBL reserves increases, which will result in higher interest credits earned on reserves. This serves to offset expenses, which increases net revenue. This means that the amount of PNRR in the revenue requirement is not the same as the net increase in expenses needed to be recovered by firm rates – the actual increase in rates only needs to recover the PNRR amounts per year less the anticipated increase in interest earned on reserves.

The anticipation of increased interest credit is straightforward, and does not include compounding. Since the impact of increasing PNRR is to increase monthly rates, the change in PBL's net revenue is assumed to come in evenly throughout the year. The change in interest for the first year in the rate period, then, is computed as one-half of the first year's PNRR times the interest rate earned on the Bonneville Fund. The increase in interest credit for the second year comprises two parts – additional interest earned on reserves due to higher revenue in the previous year, plus interest earned on reserves higher due to higher rates during the second year. This is computed as the first year's PNRR times the interest rate for the second year plus one-half of the PNRR for the second year times the interest rate for the second year. Similarly, the additional interest credit in the third year is computed as the sum of the PNRR for the first two years times the interest rate for the third year plus one-half of the PNRR for the third year times the interest rate for the third year. Since this is how the interest credit for the increment of PNRR will be treated by the more detailed BPA models during later iterations, this is how the ToolKit models the impact of PNRR on interest credit.

The next major step in this iteration is when RAM2007 calculates the rates that will be required to collect the net costs passed to RAM2007 from the revenue requirement. This calculation takes into account the fact that an increase in rates might also reduce the IOU REP Settlement benefits, depending on the influence of the cap and floor on those benefits. RAM2007 will calculate rates that are constant across the years in the rate period. BPA generally has set power rates to be constant across the years, and is proposing to do so in this proposal. Although the impact on net revenues varies from year to year due to the anticipation of increasing impacts of interest credits, BPA will levelize this impact when computing the revised rates.

The revised rates are then passed to RiskMod, which simulates 3000 games of monthly net revenues based on the higher PF rates. The distribution of net revenues is passed to the ToolKit to compute the TPP, which should be the same TPP the ToolKit calculated in the process of calculating the PNRR amount that was passed to the revenue requirement at the beginning of this iteration.

In anticipation of the iteration just described, the ToolKit tries to compute the total change in net revenue that will results from a change in PNRR in order to calculate the change in TPP that will result. The most basic change is that PF rates will go up due to including higher PNRR in the revenue requirement. The second change to incorporate is that interest credits will increase, further increasing net revenue. The next change is that the reduction in the PF rate may increase the IOU REP Settlement benefits in one or more of the three years in the rate period – and will unless this is prevented by the cap and floor on the IOU REP Settlement benefits. To balance these factors, the ToolKit needs to be able to approximate the resulting PF rate. In fact, two different PF rates – the flat-block PF rate, and the average PF rate (total PF revenues divided by total PF load in aMW). The ToolKit reads in values for the flat-block PF rate, the average PF rate, and the total PF load (excluding Pre-subscription sales) from the "IOU_Data" worksheet, where values from RAM2007 have been entered.

The ToolKit solves this equation iteratively, calculating a changed average PF rate based on the change in PNRR and interest credit, and then calculating new IOU REP Settlement benefits for each year, each of which is compared to the cap and floor. If there are any reductions in the IOU REP Settlement benefits, the PF rate is reduced, and the check is made again, until a three-year PF rate is found that produces the right net increase in net revenue taking into account the changes in interest credit and IOU REP Settlement benefits.

3.5.3.2 Updates to the Forward-Block Market Price

The IOU REP Settlement benefits are determined by the difference between the lowest PF rate and the market price. The market price for FY 2007 is set in the rate case, and therefore will be known by the time the final rates are calculated. Assumptions have to be made about the market rate for FY 2008 and FY 2009 at the time the rates are set, but the IOU REP Settlement includes provisions for recalculating the IOU REP Settlement benefits for FY 2008 and FY 2009 based on specified surveys of the market price for these years. RiskMod simulates the uncertainty in this forward price, and this is one of the values it passes to the ToolKit. In each game in the ToolKit, the ToolKit first calculates the impact of any changes in PNRR, and then recalculates the IOU REP Settlement benefits based on the new forward block-market prices (for FY 2008 and FY 2009 only; the ToolKit does not recalculate FY 2007 IOU REP Settlement benefits, since their ultimate determination comes in the final rate proposal). The net increase (decrease) in PBL net revenue is 77.4 percent of the reduction (increase) in IOU REP Settlement benefits, since 22.6 percent of the IOU REP Settlement benefits will be paid from Slice revenues.

3.5.3.3 CRAC

After the change in the IOU REP Settlement benefits in the year just starting due to the update in the forward-block market price have been calculated, the AMNR from the previous year is compared to the CRAC thresholds, and the CRAC collection amount for the current year, if any, is calculated. Once the CRAC collection amount has been calculated, including any effect on the CRAC cap from an NFB adjustment, the portions to be collected by increasing the PF rate and by decreasing the IOU REP Settlement benefits need to be computed. The reduction in the IOU REP Settlement benefits occurs by increasing the PF rate. How much the PF rate needs to be increased depends on whether the IOU REP Settlement benefits will actually change when the PF rate is increased. If the IOU REP Settlement benefits are at the floor level, they cannot be reduced, and the entire portion of the CRAC collection amount needs to be collected by increasing the PF rate, and the same is true if the unconstrained IOU REP Settlement benefits are far above the cap. In between these two situations is a numerical region where a change in the PF rate will both increase PF revenues and decrease the IOU REP Settlement benefits. Because the Slice product will pay for 22.6% of the IOU REP Settlement benefits, only 77.4% of any reduction in IOU REP Settlement benefits will contribute to the collection of the CRAC amount.

The PF rate to which the forward block market price is to be compared is a flat-block PF rate after a reduction reflecting the Conservation and Renewables Discount (CRD). The CRD is explicitly represented in the calculations. Most of the calculations are performed using the average PF rate, with a conversion factor to obtain the corresponding flat PF rate. Following are a list of definitions, the derivation of a basic result – the change in the PF rate and in the IOU REP Settlement benefits when those benefits can absorb a share of the CRAC unconstrained by the cap and floor, and then a description of the complete sequence of ToolKit calculations that includes capturing the cap and floor effects.

Definitions

Cra = the CRAC collection amount (the desired increase in net revenue)

Crd = conservation and renewables discount

H = number of hours in a year

Iou = the IOU benefits before taking the CRAC into account (after cap and floor)

IouAftCra = the IOU benefits after taking the CRAC and the cap and floor into account.

IouCraCon = the IOU share of the CRAC collection amount after accounting for caps and floors

Note that IouCraUnc = 77.4% * IouDelCon since Slice picks up part of IouDelCon

IouCraUnc = the IOU share of the CRAC collection amount unconstrained by cap and floor

Note that IouCraUnc = 77.4% * IouDelUnc since Slice would pick up part of IouDelCon

IouDelCon = the final change in IOU REP Settlement benefits after accounting for cap and floor

IouDelUnc = the delta (change) in IOU REP Settlement benefits due to the CRAC unconstrained by cap and floor

IouHeaRoo = headroom in the IOU benefits – the amount the unconstrained benefits are above the cap (could be zero)

IouLoa = IOU nominal load (2200 aMW)

IouUnc = what the pre-CRAC IOU benefits would have been if unconstrained by the cap and floor

Mkt = flat-block forward market price

PfAftCra = the average PF rate after calculating the impact of the CRAC on the IOU benefits including the cap and floor.

PfAve = average PF rate (total PF revenues divided by total PF MWh) before the CRAC

PfCraCon = the regular PF share of the CRAC amount after accounting for caps and floors

Note that Cra = PfCraCon + IouCraCon = PfCraCon + .774 * IouDelCon

PfCraUnc = the regular PF share of the CRAC collection amount unconstrained by cap and floor

Note that Cra = PfCraUnc + IouCraUnc = PfCraUnc + .774 * IouDelUnc

PfDif = the difference between the flat and average PF rates, i.e., PfDif = PfAve – PfFla

PfFla = flat-block PF rate before the CRAC

PfLoa = PF load in aMW (non-Slice)

PfOnlCra = the part of the CRAC that has to be picked up solely by the PF loads because the IOU benefits are above the cap (does not take into account the floor)

PfRatHeaRoo = headroom in the PF rate – the amount the PF rate could increase before the IOU benefits would start to be affected (could be zero)

ShaCra the part of the CRAC that will be shared between the IOU benefits and the PF load (does not take into account the floor)

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

We begin by ignoring the cap and floor.

1. Iou = (Mkt – (PfFla – Crd)) * IouLoa*H ,   by Settlement.
2. Iou = Mkt * IouLoa*H – (PfFla – Crd) * IouLoa*H
3. Iou = Mkt * IouLoa*H – (PfAve – PfDif – Crd) * IouLoa*H

After the CRAC, the equation must still hold, but with adjustments to reflect possible decreases in Iou, and an increase in the average PF rate, PfAve, calculated by dividing the PF portion of the CRAC amount by the average PF load, shown below as PfCraUnc / PfLoa*H.

4. Iou – IouDelUnc = Mkt * IouLoa*H – (PfAve – PfDif – Crd + PfCraUnc / PfLoa*H) * IouLoa*H

5. Iou – IouDelUnc = Mkt * IouLoa*H – (PfAve – PfDif – Crd) * IouLoa*H – PfCraUnc * IouLoa*H / PfLoa*H

We can use 3. to subtract Iou from left side, and Mkt * IouLoa*H – (PfAve – PfDif – Crd) * IouLoa*H from the right side, leaving:

6. –IouDelUnc = –PfCraUnc * IouLoa*H / PfLoa*H, or

7. IouDelUnc = PfCraUnc * IouLoa*H / PfLoa*H

Since Cra = .774 * IouDelUnc + PfCraUnc, we know that PfCraUnc = Cra – .774 * IouDelUnc, therefore

8. IouDelUnc = (Cra – .774 * IouDelUnc) * IouLoa*H / PfLoa*H

9. IouDelUnc = Cra * IouLoa*H / PfLoa*H – .774 * IouDelUnc * IouLoa*H / PfLoa*H

10. IouDelUnc + .774 * IouDelUnc * IouLoa*H / PfLoa*H = Cra * IouLoa*H / PfLoa*H

11. IouDelUnc * PfLoa*H + .774 * IouDelUnc * IouLoa*H = Cra * IouLoa*H

12. IouDelUnc * (PfLoa*H + .774 * IouLoa*H) = Cra * IouLoa*H

13. IouDelUnc = Cra *IouLoa*H / (PfLoa*H + .774 * IouLoa*H)

14. IouDelUnc = Cra * IouLoa / (PfLoa + .774 * IouLoa)

Only some of the change in IOU REP Settlement benefits contributes to PBL net revenue:

15. IouCraUnc = .774 * IouDelUnc

16. IouCraUnc = Cra * .774 * IouLoa / (PfLoa + .774 * IouLoa)

3.5.3.3.2 The ToolKit Calculations Including Effect of Cap and Floor

First we check to see if the initial unconstrained IOU REP Settlement benefits, IouUnc, are above the cap. If so, the benefits have some "headroom", and at least some of the CRAC will have to be collected solely from the PF rate. This will raise the PF rate, and could raise it enough that some of the CRAC amount can then be collected from the IOU REP Settlement benefits. The amount of increase in the PF rate that would reduce the IOU REP Settlement benefits to the cap, The PF rate headroom, or PfRatHeaRoo, is calculated, and the amount of the CRAC amount that can be collected by that PF rate increase, PfOnlCra, is calculated. This amount will be zero if the unconstrained IOU REP Settlement benefits are at or below the cap. If the entire CRAC amount can be collected without raising the PF rate to the point that the IOU REP Settlement benefits would go below the cap, then this will be done: the entire CRAC amount is collected from the PF rate, and the IOU REP Settlement benefits do not change.

17. IouUnc = (Mkt – (PfAve - PfDif - Crd) * IouLoa*H

18. IouHeaRoo = IouUnc – 300

19. IouHeaRoo = max(0, IouHeaRoo)

This is the amount of change in the unconstrained IOU REP Settlement benefits that can occur without changing the constrained IOU benefits, i.e., benefits after the cap and floor. The PF rate change that would cause this change in IOU benefits is based on the non-Slice share of this change. From 1. we have:

20. $(Iou + IouHeaRoo) = (Mkt – (PfAve – PfDif – Crd) + PfRatHeaRoo) * IouLoa*H$

21. $Iou = (Mkt – (PfAve – PfDif – Crd)) * IouLoa*H$, therefore

22. $IouHeaRoo = PfRatHeaRoo * IouLoa*H$, or

23. $PfRatHeaRoo = IouHeaRoo / IouLoa*H$

The PF rate headroom, like the IOU headroom, can be zero, but not negative. Next we need to compute how much CRAC revenue a PF rate increase of this size could collect.

24. $PfOnlCra = PfRatHeaRoo * PfLoa*H$

This is the amount of the CRAC (if any) that will be collected solely from the PF revenues (not counting the effect of the floor). The remainder will be collected from both the IOU REP Settlement benefits and the PF rate, unless prevented by the floor. A check for that will be performed later.

25. $ShaCra = Cra – PfOnlCra$

Now we assume that Iou can adjust, and calculate the amount of the shared CRAC, ShaCra, that reductions in the IOU benefits will collect. We use the result from equation 14. to calculate how much the IOU benefits would change without the floor.

26. $IouDelUnc = ShaCra * IouLoa / (PfLoa + .774 * IouLoa)$

Equation 26 assumes the IOU REP Settlement benefits can adjust fully downward. We need to find out how far they can adjust before they hit the floor. We will reduce the pre-CRAC IOU benefits by the results of 26., and compare to the floor.

27. $IouAftCra = Iou - IouDelUnc$

28. $IouAftCra = \max(100, IouAftCra)$

Then the actual change in IOU REP Settlement benefits:

29. $IouDelCon = Iou - IouAftCra$

The amount of the CRAC collection amount that can be collected from IOU REP Settlement benefits:

30. $IouCraCon = .774 * IouDelCon$

The amount of the CRAC collection amount to be collected from PF loads:

31. $PfCraCon = Cra - IouCraCon$

The revised average PF rate can be computed:

32. $PfAftCra = PfAve + PfCraCon / (PfLoa*H)$

In summary, to collect the amount c of additional net revenue, the flat block PF rate must be increased by the quantity PfCraCon / (PfLoa*H) (to be accomplished by increases in only the energy components of the flat block rate). This will cause the IOU REP Settlement benefits to decrease by IouDelCon, which is either equal to the change in the flat block PF rate multiplied by iLh (2200 * 8760, or 8784 in FY 2008), or a smaller amount due to the constraints of the cap or floor. This is the total change in IOU benefits for that year. Of that total, 22.6% affects the

Slice loads, and will result in a change in the Slice true-up of that amount in favor of the Slice customers, and 77.4% of that amount (IouCraCon) will be a reduction in PBL expense that will contribute to PBL reserves. The sum of IouCraCon and PfCraCon will equal the CRAC collection amount.

3.5.3.4 DDC

After calculations of the CRAC amount and its net revenue and TPP impacts, if any, the DDC is assessed. If there is a CRAC, there cannot be a DDC, since they both trigger on the basis of AMNR, and their thresholds are at least $300 million apart. The possibilities are 1) only a CRAC; 2) only a DDC; or 3) neither. The computations for the PF and IOU shares of the DDC amount are exactly parallel to those for the CRAC above except for the reversal of signs, and the constraint that the DDC cannot be so large as to reduce the LLH energy rate below $1 per MWh.

3.5.3.5 Secondary Revenue Rebate

After the CRAC and DDC computations are complete, the computations for a secondary revenue rebate are made, if such a rebate has been included in the risk mitigation package. The calculations for the PF and IOU shares of a rebate amount are exactly parallel to those for the CRAC above except for the reversal of signs. The calculations in the ToolKit have assumed that this is an annual calculation, but other rebate designs could be contemplated that calculate and distribute rebates more frequently than once a year. A secondary revenue rebate could occur during a year in which a CRAC is being applied, or during a year in which a DDC is being applied, or during a year in which neither is being applied.

3.5.4 U.S. Treasury Deferral Modeling

In the traditional deferral logic, labeled "Old" on the ToolKit's main page, each year starts with the ending reserves from the previous year. Net revenues are then added, and the translation from net revenue to cash is then made via the accrual to cash adjustment.. Interest credit is calculated on both the starting reserves and on the net cash flow for the year. The total is calculated and compared to the level of liquidity reserve requirement assumed for the run ($50 million for all runs reported in the Risk Mitigation Study). If the ending cash balance is below the level of liquidity reserves, this indicates that making the full U.S. Treasury payment would leave BPA short of liquidity reserves, and a deferral is made. First Federal amortization is deferred (rescheduled) out of the current rate period. Interest is calculated on this deferred amount, and is payable annually. If deferring the entire amount of amortization is not sufficient to leave BPA with its (input) working capital, then interest payments are deferred. These payments become due the next year, along with one year of interest. (All interest calculations use the interest rate BPA receives on the Bonneville Fund, which is the weighted average interest for BPA's Federal debt.) A year cannot end with reserves lower than the liquidity reserve level under the traditional logic.

In the SN CRAC initial rate proposal, BPA defined a second TPP standard, the U.S. Treasury Recovery Probability (TRP), because BPA was proposing to use a much lower TPP standard than called for by the 10-Year Financial Plan and believed an additional metric was needed to ensure eventual repayment of BPA's obligations to the U.S. Treasury. TRP is the probability that the sum of all of the scheduled payments to the U.S. Treasury in a rate period will have been repaid by the end of the rate period, even if some of the early payments were not made on time. New logic (labeled "new" on the ToolKit's main page) was added to the ToolKit to measure TRP. Under this new logic, the year-end cash balance is calculated as before, and compared to the working capital level. If the cash balance is below the working capital level, a deferral is noted for later reports, but the ending reserves are allowed to go negative. This is essentially the same as deferring all of the missed payments, amortization as well as interest, until the next year. A U.S. Treasury payment will only count as being made successfully under this logic if any misses from previous years have been made up and the currently scheduled payment is made. BPA is not using TRP in this rate proposal.

Closer examination of the probably timing of events as modeled in the traditional logic has caused BPA to develop a third way of modeling U.S. Treasury deferrals (labeled "Hybrid" on the ToolKit's main page). Consider the current situation. This initial proposal is being created during late FY 2005 and early FY 2006. Suppose FY 2006 is a bad year for BPA and BPA is not able to make the full U.S. Treasury payment at the end of the year. The traditional deferral logic says to defer payment of principal until the next repayment study. But the repayment study for the FY 2007 – 2009 period will already have been performed in the FY 2007 rate case prior to the deferral, so the "next" repayment study will be the one performed for the FY 2010 rate case, and the earliest adjusted payments that will begin repayment of the deferred principal would be in 2010.

Given the heightened scrutiny being given to BPA's finances by its diverse stakeholders in the Pacific Northwest, Washington D.C., and elsewhere, BPA decided it would be prudent to model an earlier commencement of adjusted payments of any deferred principal. BPA does not have a formal policy on this issue, but for TPP modeling, BPA is now assuming the following. In the event of a deferral of payments of principal to the U.S. Treasury in the ToolKit, BPA will model a balance of deferred payments, and will repay this balance to the U.S. Treasury at its first opportunity. "First opportunity" is defined for TPP calculations as the first time BPA will end a fiscal year with more than $100 million above its minimum liquidity level. The PBL minimum liquidity level in this proposal is $50 million, so this means that BPA is modeling the repayment as occurring as soon as possible while not bringing the level of PBL reserves below $150 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.

Another ToolKit change related to U.S. Treasury deferrals is that the liquidity reserve level can be changed between the FY 2002 – 2006 rate period and the FY 2007 – 2009 rate period. However, BPA is not proposing a change, and intends to use the same liquidity reserve level, $50 million, when modeling both rate periods.

3.5.5 New Outputs

Two new worksheets displaying results of each ToolKit run have been added. The first worksheet, "Graphs", shows the variability of rates and financial reserves; the second, "IOU_Adj", shows the results of calculations of the impact of PNRR, updated forward flat-block prices, CRACs, DDCs, and a possible secondary revenue rebate on the IOU REP Settlement benefits and on the average PF rate.

3.5.5.1 Graphs

Rate variability is an important characteristic of many rate designs. To portray that variability and allow for comparing the variability of alternative rate designs, a worksheet named "Graphs" has been added to the ToolKit which illustrates the variability of the PF rate induced by any variable rate mechanisms included in an analysis. The ToolKit can model the CRAC, the DDC, and a secondary revenue rebate, but these features may not all be used in any particular analysis. The Graphs sheet also shows ending PBL reserve balances for FY 2006 through 2009, and illustrates the variability of those balances.

The variability is shown by two devices. The first is a hollow box superimposed on the column representing the expected value. The top of the box indicates the 75th percentile of the PF rate or the reserve balances (over the distribution of 3000 games); the bottom of the box indicates the 25th percentile. There is a 50 percent probability that the result from any one game will fall between those two values. The second device is a bold vertical line that runs from the maximum value down to the minimum value (over the distribution of 3000 games). The max-min lines on the reserves chart never go below $50 million; that is the level of required liquidity reserves, and the ToolKit will defer portions of the annual U.S. Treasury payment rather than let the year-end reserve level fall below this point. The max-min lines on the PF rate chart sometimes go below the bottom of the chart; the rate scale runs from $20 to $40 per MWh, and in some of the 3000 games the net revenue in one year is high enough that the DDC in the next year reduces the average PF rate to less than $20 per MWh. The rate depicted on these graphs is an average PF rate after deducting $0.89 per MWh for the operating and regulating reserve credit. This rate has not had Conservation and Renewables Discount deducted.

3.5.5.2 IOU REP Settlement Benefits Output

A new sheet, "IOU_Adj", has been added to the ToolKit to report on the many calculations the ToolKit makes that involve IOU REP Settlement benefits. This sheet shows the results for each of the 3000 games and eight summary statistics:

- Maximum,
- 75th percentile,
- Mean,
- Median,
- 25th percentile,
- Minimum,
- Range, and
- Standard deviation.

The values reported for each of the three year in the FY 2007 – 2009 rate period are the following:

- Flat-block market prices – the prices used in RAM2007 for IOU REP Settlement benefit calculations, and for FY 2008 and 2009, the updated flat-block market prices simulated in RiskMod;
- Average PF rates (not block rates) – the values calculated in RAM2007, the value after the effect of any additional PNRR calculated by the ToolKit, the effective rate after the impact of the CRAC or DDC, and the final effective rate after including the effect of any secondary revenue rebate;
- CRAC results – the total CRAC collection amount, the portion of the collection amount to be collected from PF rates, the portion of the collection amount collected from the non-Slice share of any reductions in the IOU REP Settlement benefits, and the total change in IOU REP Settlement benefits due to the CRAC (not just the non-Slice share);
- DDC results – the total DDC distribution amount, the portion of the distribution amount to be distributed to PF rates, the portion of the distribution amount distributed via the non-Slice share of any increases in the IOU REP Settlement benefits, and the total change in IOU REP Settlement benefits due to the DDC (not just the non-Slice share); and
- Secondary revenue rebate results – the total rebate distribution amount, the portion of the distribution amount to be distributed to PF rates, the portion of the distribution amount distributed via the non-Slice share of any increases in the IOU REP Settlement benefits, and the total change in IOU REP Settlement benefits due to the rebate (not just the non-Slice share).

3.6 ToolKit Inputs and Assumptions

For BPA’s Proposal, some of the ToolKit inputs are slightly different for the other risk mitigation packages described in the next section, and these differences are noted in the descriptions of the other packages.

3.6.1 Inputs and Assumptions on the ToolKit Main Page

3.6.1.1 Risk Analysis Model (RiskMod)

Separate RiskMod runs were made to develop distributions for FY 2005-2006 and FY 2007-2009 rate period that reflect system augmentation, market prices, various other changes, and an assumption that 22.6 percent of the Federal system output goes to Slice customers. (Reference documentation)

3.6.1.2 Non-Operating Risk Model (NORM)

A NORM distribution for the FY 2007-2009 period that reflects the uncertainty around non-operating expenses. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A.

3.6.1.3 Starting Reserves

The 3000 FY 2007 starting reserve values have an expected value of $381 million based upon the FY 2005 Third Quarter Review forecast. This results from a starting FY 2005 known value of $402 million and the simulation of the remainder of FY 2005 and all of FY 2006.

3.6.1.4 Starting AMNR

The 3000 FY 2007 starting AMNR values have an expected value of -$236 million based upon the FY 2005 Third Quarter Review forecast. This results from a starting FY 2005 known value of -$520 million and the simulation of the remainder of FY 2005 and all of FY 2006.

3.6.1.5 Treatment of U.S. Treasury Deferrals

U.S. Treasury deferrals are treated using the “Hybrid” logic described above.

3.6.1.6 Other Agency Reserves Temporarily Available

Cells D25:D26 on the ToolKit's main page show the assumption that BPA can consider in rate-making that there is $55 million available to PBL in FY 2007 because TBL's TPP in the analyses for its FY 2006 – 2007 rate case was higher than 95 percent. This assumption is modeled by showing an increment of $55 million of cash (no change in net revenue) in FY 2007. This cash, like other PBL cash in the Bonneville fund at the U.S. Treasury, earns interest during FY 2007. Then a decrement of cash is shown in FY 2008 in the amount of $55 million * 1.0475 = $57.6 million. Including this in each game regardless of PBL's financial condition does not bias the analyses, because PBL earns as much interest on the $55 million as it relinquishes in FY 2008.

3.6.1.7 Interest Rate Earned on Reserves

Interest earned on PBL's reserves is calculated at the rate of 4.75 percent per year.

3.6.1.8 Interest Credit Assumed in the Net Revenues

A basic feature of the ToolKit is that the interest earned on reserves which is included in the revenue requirement is deterministic, that is, it does not take into account the variation in reserves levels from one game to another. . To capture the interest effects of this variability, the revenue requirement assumptions about interest earned on reserves is backed out of all ToolKit games and replaced with game-specific calculations of interest credit. The revenue requirement amounts that are backed out are $10.0 million, $10.5 million, and $10.3 million for FY 2007, FY 2008, and FY 2009 respectively.

3.6.1.9 The Cash Timing Adjustment

The cash timing adjustment reflects the interest credit impact of the typical shape of PBL's reserves throughout a fiscal year. Reserves typically do not change much in the first few months of a fiscal year – they may decline or increase a little, but not much. As net billing winds down, with the Energy Northwest budget nearly fully paid, PBL's reserves begin to build up. This build-up typically continues from the winter through the end of spring. Then when net billing for the next year starts to affect PBL's receipt of cash from power revenues in June, the reserve build-up slows down. The interest credit calculations for the revenue requirement and in the ToolKit assume that the reserve balance changes linearly throughout the year; they ignore the spring bulge. The cash timing adjustment is a number from the repayment study that approximates the additional interest credit earned on the spring bulge. The cash timing adjustments for this proposal are $7.2 million, $7.5 million, and $7.4 million for FY 2007, FY 2008, and FY 2009 respectively.

3.6.1.10 Other Cash Adjustments

There are two types of adjustments to cash in this range of cells on the ToolKit main page. The first affects only FY 2006, and reflects the payment of $4.1 million to be made in FY 2006 as part of the repayment of $55 million of benefits owed to the IOUs for FY 2003. This is shown as a cash-only adjustment because it was recorded as an expense in FY 2003. The second type of cash-only change results from a change to BPA's repayment plans that was made after the repayment study for the initial proposal was made in August 2005. Since then, BPA has planned to make an assumption about the way it will pay third-party debt that will effectively reduce the debt service in FY 2007 – 2009. The change is to assume that third-party debt will be paid in 2013 instead of 2017. This change reshapes the repayment streams over the whole time horizon of the repayment study, and reduces the planned debt service for FY 2007, FY 2008, and FY 2009 by $23.1 million, #12.2 million, and $23.1 million respectively. These amounts are shown as additions to cash in the ToolKit because the reductions in debt service are mainly reductions in amortization of Federal debt, and such amortization is a use of cash but not an expense.

3.6.2 Inputs on the ToolKit "IOU_Data" Sheet

3.6.2.1 Flat-Block Forward Market Prices

The per-MWh flat-block forward market prices assumed in RAM2007 are $52.07, $49.85, and $45.84 for FY 2007, 2008, and 2009 respectively. The updated flat-block forward market prices for each game are too numerous to list here but can be found in the RiskMod output file or in the ToolKit's "IOU_Adj" worksheet.

3.6.2.2 PF Rates (Before ToolKit Adjustments)

Several rate outputs from the RAM2007 are passed to the ToolKit. These are the per-year values for the flat-block PF rate, the average PF rate (the total PF revenues divided by the total PF load in average MW), and the average PF load. These are needed to allow the ToolKit to calculate PF rate impacts of several changes, such as changes in PNRR or CRAC amounts that affect the IOU REP Settlement benefits by affecting the PF rate. The pre-ToolKit average rate is $31.10 per MWh for all three years, without the credit for operating and regulating reserves; the pre-ToolKit flat block rate is $29.83 per MWh for all three years, without the credit for operating and regulating reserves. The forecasts of PF loads subject to the CRAC and DDC (this excludes Slice sales and Pre-Subscription sales) are 5,154 aMW, 5,195 aMW, and 5,234 aMW for FY 2007, FY 2008, and FY 2009 respectively.

3.6.2.3 Pre-ToolKit IOU REP Settlement benefits

The results of the IOU REP Settlement benefit calculation in RAM2007 forecast that the benefits for each year in the FY 2007-2009 rate period will be at the cap of $300 million.

3.6.2.4 Flat PNRR Rate Impact & PNRR Shape

The "Flat PNRR Rate Impact" box needs to be checked: BPA needed to make changes in the ToolKit to match the rate-making logic of the Rates Analysis Model more closely that disabled the Shaped PNRR feature. The cells for the shaping factors should also reflect this by having the number 1 entered into each of the cells corresponding to FY 2007, FY 2008, and FY 2009.

4. RISK MITIGATION PACKAGES

Several risk mitigation packages are described verbally and quantitatively below. Only one, the first one, is BPA's Initial Proposal. The modeling of this package was more complete. For example, after calculation of the required PNRR by the ToolKit, the PNRR amount was fed back into the revenue requirement, which affected some Slice calculations, a new Rates Analysis Model run was made, with higher rates reflecting the impact of PNRR, and a new RiskMod run was made. This final iteration was only performed for BPA's proposal.

The results of the TPP analyses of these packages are shown below in Table 5. Additional details of the analytical results are provided in the documentation, where the ToolKit main page, a page of graphs, and the output of the calculations covering the interaction of PNRR, updating market prices, any CRAC, DDC, or secondary revenue rebate, and the level of IOU REP Settlement benefits.

4.1 BPA's Proposal: Reserves, Fixed PNRR, CRAC, and DDC

BPA's proposal includes a CRAC with a $300 million cap on the annual collection amount. The trigger is the AMNR equivalent of $470 million in PBL reserves at the end of FY 2006 for the CRAC that applies to FY 2007 rates, and the equivalent of $500 million for the CRACs that applies to FY 2008 and FY 2009. BPA is not proposing to exclude any PBL costs from the CRAC calculations. The annual cap may be adjusted by the NFB adjustment which would be triggered by certain changes in fish mitigation expenses and operations. A DDC is included; its trigger is the AMNR equivalent of $800 million in PBL reserves at the end of FY 2006 for the

DDC that applies to FY 2007, and the same amount for the DDCs that apply to FY 2008 and FY 2009. There is a cap on the DDC distribution: the DDC distribution cannot be large enough that the average annual LLH energy rate is reduced below $1 per MWh. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A.

4.2 Reserves, Shaped PNRR and DDC

In discussions with interested parties during FY 2005, BPA had indicated that it would analyze a "shaped" PNRR alternative. BPA's traditional implementation of PNRR has been to include the same amount of PNRR in each year of a rate period. However, because FY 2007 was seen as the pinch-point for TPP in the FY 2007-2009 rate period, the amount of PNRR needed for FY 2007 is greater than the amount needed for FY 2008 or FY 2009, especially in packages that do not include a CRAC. Shaping the PNRR so that the FY 2007 amount is greater than the FY 2008 or FY 2009 amount can reduce the rate-period total PNRR substantially. However, it became necessary to make some changes to the rate-adjustment code in the ToolKit to make it match more closely the code actually used by BPA to set rates in the RAM2007, and these changes have precluded using shaped PNRR. Few parties inside or outside BPA appeared to be interested in this alternative, because while it yielded lower average rates for the three-year period, it produced higher rates for FY 2007. Nonetheless, BPA reports here approximate impacts of shaping PNRR from preliminary runs in order to show parties the effect that this option could have.

4.3 Reserves, Fixed PNRR and DDC

This package is very similar to BPA's proposal except for the omission of the CRAC. Rates in this package are still quite variable because of the variable impact of the DDC in FY 2008 and FY 2009. The DDC is the same as the DDC in BPA's proposal – it triggers at the AMNR equivalent of $800 million in PBL reserves as forecast shortly before the beginning of each fiscal year in the rate period. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A.

4.4 Secondary Revenue Rebate, Fixed PNRR, CRAC, and DDC

This package includes a rebate of net secondary revenues above a specified value. In BPA's proposal, rates are calculated from a revenue requirement in which 100 percent of the expected value of net secondary revenue has been credited against costs. On an expected-value basis, revenues will equal costs, but there can be years in which revenues are very substantially below costs, and the risk mitigation package in BPA's proposal is calibrated to mitigate those risks sufficiently to meet BPA's TPP standard. The risk mitigation in the secondary revenue rebate package is quite different. Only 75 percent of the expected value of net secondary revenues is credited against costs in the rates calculations, but any net secondary revenue beyond that value is rebated to customers. Since a smaller amount of net secondary revenue is assumed, the risk of shortfall is reduced, and PBL does not need to have as large a buffer of reserves to get through dry years. This reduces the net cost of the risk management package. On the other hand, again because a smaller credit of net secondary revenue is assumed, the rates paid by customers starting October 1 of each fiscal year are higher, but these rates will almost always be offset by a rebate later in the year. The ToolKit is an annual model, and does not model timing distinctions for events within a year. Therefore, this package does not have an explicit assumption about when a rebate would be made, except that it occurs before the end of the fiscal year in which it would be earned.

Because changes in firm load will affect how the level of Trading Floor purchases and sales, we make an adjustment to the rebate concept, and use total sales minus total purchases as the metric. The problem we are fixing is that if, for example, regional economic activity picked up considerably, and BPA sold more power to its full requirements customers, Trading Floor spot sales would decrease. This would reduce the average amount of the rebate, which is an effect we don't want. The rebate to customers should be affected as little as possible by changes in other loads. The way we have modeled this is in the definition of the metric used to calculate the size of the rebate. Instead of calculating Trading Floor sales minus Trading Floor purchases, we calculate total sales minus total purchases. The threshold against which this is compared is not 75% of the expected value of Trading Floor purchases minus 100% of the Trading Floor purchases, but 75% of the expected value of Trading Floor sales plus 100% of the expected value of all other firm sales minus 100% of the expected value of total purchases (all figures computed after accounting for Slice). Calculated this way, the rebate is less sensitive to changes in BPA's load/resource balance.

The rebate calculation is made by adding a formula to the RiskMod output workbook. The ToolKit reads in the result of this calculation. We took a shortcut with the rate and PNRR calculations. In order to approximate the results of this risk mitigation package without having to run complete iterations of all of our models at a time when preparation of our initial proposal was our highest priority, we started with rates that do include a credit for 100% of Trading Floor sales. This means that the starting rates calculated by the Rates Analysis Model for this alternative are understated; there should be a smaller credit for secondary sales, which would mean a higher starting rate. This is compensated for by an increase in PNRR, and except for possible changes in the relative amount of PNRR in each year of the rate period, the increase in PNRR should be exactly enough to replace the revenue that should have been generated by starting with higher pre-PNRR rates, and the rates after adding PNRR in this alternative should be very similar to the total rates after PNRR if we had run this alternative through our complete loop of models. The PNRR value shown for this alternative is not really all PNRR; some of it is the replacement for the revenue that should have been generated by starting rates that should have been higher, and the rest is really PNRR.

This package also includes the DDC from BPA's proposal and a CRAC with an annual cap of $200 million to deal with risk that is not associated with secondary sales and purchases. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A.

4.5 Smaller CRAC Package

To illustrate the impact on average rate levels and rate variability of the cap on the CRAC, two sensitivities packages are shown here that are identical to BPA's proposal except for the CRAC cap. The first one reduces the maximum annual collection from $300 million to $200 million. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A.

4.6 Larger CRAC Package

This is the second package examining the impact on average rate levels and rate variability of the cap on the CRAC. This package is identical to BPA's proposal except that the maximum annual collection has been increased from $300 million to $400 million. *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A.

4.7 Results

Summary results for BPA's proposal and the other risk mitigation packages presented for comparison are shown in Table 5. The rate figures are average PF rates, that is, the forecast of total PF non-Slice revenues divided by the total non-Slice load in average megawatts. This rate has been decreased by $0.89 to reflect the impact of the credit for Operating and Regulating Reserves, but has not been decreased to reflect the Conservation and Renewables Discount. It is an expected value over 3,000 games in each of which a DDC, CRAC, or rebate might have been made.

Table 5

Summary Results

	$400 Million CRAC	BPA's Proposal	$200 Million CRAC	No CRAC	Sec. Rev. Rebate
Annual CRAC Cap	400	300	200	0	200
Annual DDC Cap	1,300	1,300	1,300	1,300	1,300
PNRR	76	101	145	301	168
Sec. Rev. Rebate included?	No	No	No	No	Yes
E.V. 2007 Rate	31.6	31.9	32.4	34.2	27.3
E.V. 2008 Rate	30.2	30.2	30.3	31.3	28.8
E.V. 2009 Rate	27.8	27.9	28.0	28.1	28.1
E.V. 3-Yr Ave. Rate	29.8	30.0	30.3	31.2	28.1
50% Conf Int 2007 Rate	29.8 -- 32.5	30.3 -- 33.1	31.2 -- 34.0	34.2 -- 34.2	23.6 -- 31.6
50% Conf Int 2008 Rate	29.6 -- 33.4	29.7 -- 33.9	29.8 -- 34.4	30.6 -- 34.2	25.6 -- 33.1
50% Conf Int 2009 Rate	25.5 -- 29.8	25.4 -- 30.3	25.2 -- 31.2	24.6 -- 34.2	25.2 -- 31.6
50% Conf Int 3-Yr Ave Rate	27.7 -- 32.3	28.0 -- 32.5	28.3 -- 32.7	29.4 -- 34.2	25.0 -- 31.7
E.V. 2006 PBL Reserves	381	381	381	381	381
E.V. 2007 PBL Reserves	705	717	742	815	506
E.V. 2008 PBL Reserves	774	793	835	973	511
E.V. 2009 PBL Reserves	735	763	817	988	485
50% Conf Int 2006 PBL Res.	282 -- 503	282 -- 503	282 -- 503	282 -- 503	282 -- 503
50% Conf Int 2007 PBL Res.	427 -- 938	433 -- 957	450 -- 989	498 -- 1091	406 -- 642
50% Conf Int 2008 PBL Res.	506 -- 1017	519 -- 1050	558 -- 1108	667 -- 1290	433 -- 635
50% Conf Int 2009 PBL Res.	467 -- 991	482 -- 1030	531 -- 1093	688 -- 1282	361 -- 621

A comparison of four of these packages, No CRAC, $200M CRAC, $300M CRAC (BPA's Proposal), and $400M CRAC illustrates some of the key trade-offs involved in rate design. As the size of the cap on the CRAC is increased, the expected value of the three-year average rate declines, and the expected value of PBL's ending reserves declines for each of the three years in the rate period. This comes at the prices if greater potential changes in the regular PF rate from year to year and a bigger possible rate increase from the base rates that would be published in the ROD. Note that some rate variability exists even in the No CRAC alternative because of the operation of the DDC.

The Secondary Revenue Rebate alternative is quite different. The rates published in the ROD would be higher, and the expected value of the rates as adjusted by the CRAC or DDC taking effect each October 1 would be higher, but the net effective rate, including the impact of the rebate, would be lower. The variability of rates would be higher, as much of the risk or uncertainty of secondary sales would be passed through to customers. The benefit customers would get from that is a much lower average level of PBL reserves – they would not have to pay to build up this risk mitigation buffer, and the results is an expected value three-year average rate that is $1.7 per MWh lower than any of the other packages.

Three pages of extended results are reported for each of the five risk mitigation packages in the Study Documentation, WP-07-E-BPA-04A, including statistics on the IOU REP Settlement benefits under different CRAC and rebate alternatives.

4.8 Conclusion

BPA is proposing a risk mitigation package that is fairly traditional – all of the major elements were part of the rates for FY 2002 – 2006. We are proposing a CRAC that has a cap on annual collection of $300 million, which is less than the total that could be collected by the current SN CRAC and FB CRAC together. A smaller (or non-existent) CRAC could be substituted; this would decrease rate variability (especially in the first years before the probability of a DDC becomes substantial) but would increase the expected value of the rates non-Slice customers would pay. A larger CRAC could be adopted, which could reduce the expected value of non-Slice rates a little, but would increase the maximum size of rate increase customers could *See,*.

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