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 Final Proposal

RISK ANALYSIS STUDY

July 2006

WP-07-FS-BPA-04

RISK ANALYSIS

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COMMONLY USED ACRONYMS

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

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

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

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

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

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

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

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

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1. INTRODUCTION

1.1 Background

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

Two statistical models are used in the risk analysis step for this rate proposal, the Risk Analysis Model (RiskMod), and the Non-Operating Risk Model (NORM), while a third model, the ToolKit, is used to test the effectiveness of rate tools options in the risk mitigation step. RiskMod is discussed in Sections 2.1 through 2.4, the NORM is discussed in Section 2.5, and the ToolKit is discussed in Section 3.

The models function together so that BPA can develop rates that cover all of its costs and provide a high probability of making its Treasury payments on time and in full during the rate period. By law, BPA's payments to Treasury are the lowest priority for revenue application, meaning that payments to Treasury are the first to be missed if financial reserves are insufficient to pay all bills on time. For this reason, BPA measures its potential for recovering costs in terms of probability of being able to make Treasury payments on time (also known as Treasury Payment Probability or TPP).

In its 1993 rate filing, BPA implemented a long-term policy for meeting its obligations for repaying the U.S. Treasury. At that time, two repayment probability goals were set: one short-term and one longer-term. The short-term goal was to ensure a 95 percent probability of making both of the annual Treasury payments in the two-year rate period on time and in full. The longer-term goal, described in the 10-Year Financial Plan, was to maintain that 95 percent rate period standard for five consecutive two-year rate periods. BPA continues to adhere to these 10-year Financial Plan objectives for the 2007 Rate Case. This TPP standard was established as a rate period standard; that is, it focuses upon the percentage of time BPA successfully makes all of its payments to Treasury over the entire rate period rather than setting numerical goals for year-to-year performance.

Among the uncertainties that BPA must mitigate, the most variation is linked directly hydro conditions, market prices and river operations for fish recovery. Uncertain hydro conditions and market price volatility present challenges for BPA in its efforts to keep its power rates as low as possible while fully meeting its obligations to the U.S. Treasury. Much of the power generated by BPA is hydro-based and annual generation is a direct function of precipitation in the Columbia Basin. As a result, BPA has little control over the amount of available generation from year to year. Increased wholesale market price volatility also significantly changes the profile of risk and uncertainty facing BPA and its stakeholders. Higher, more volatile natural gas prices, a key factor in the pricing of electricity, are increasing the variability in BPA's net secondary revenues from year to year. As a result, BPA faces greater uncertainty of not achieving the particular level of net secondary revenues that are assumed in setting base power rates. These uncertainties are discussed in Section 2 and in the accompanying documentation, WP-07-BPA-FS-04A.

Further uncertainty for BPA arises from the financial impacts of changing river operations for fish mitigation. As a result of ongoing litigation around the FCRPS 2004 Biological Opinion (BiOp), a new BiOp or other court-ordered changes to river operations in FY 2007-2009 may reduce BPA's net revenues upon which final rates are based. To address this uncertainty, BPA is adopting several new risk mitigation mechanisms that address this revenue uncertainty and its resulting impact on TPP.

Finally, the FY 2007-2009 risk analysis also includes new operational risks analyzed through RiskMod, as well as a more comprehensive analysis of non-operating risks analyzed through the NORM.

The tools that BPA uses to address these risks include Planned Net Revenues for Risk (PNRR); a Cost Recovery Adjustment Clause (CRAC); an NFB Adjustment; an Emergency NFB Surcharge (NFB Surcharge); and finally, a Dividend Distribution Clause (DDC).

Given the large magnitude of the uncertainties, if BPA were to rely solely on adding PNRR to the power rates, they would need to include a large risk premium to meet BPA's TPP standard. As an alternative to high fixed PNRR, BPA is implementing a risk mitigation package that balances PNRR with a variable rate mechanism, relying on the CRAC and DDC to work with PNRR to achieve the BPA's policy objectives, including the TPP objective of 92.6 percent. This risk mitigation package is less expensive on an expected value basis because the rates can be adjusted annually to respond to uncertain financial outcomes, and additional revenues are collected only when financial conditions require them.

Due to the uncertainty associated with the 2004 FCRPS BiOp litigation, BPA included the NFB Adjustment to allow the CRAC to recover increased costs resulting from litigation-related expenses and river operations. In response to issues raised by rate case parties to BPA's Initial Proposal, BPA is now including the NFB Surcharge. The NFB Surcharge triggers if there are FCRPS 2004 BiOp related litigation costs and if the Agency Within-year TPP is determined to be below 80 percent. If this situation arises during FY 2007-2009, BPA will levy a surcharge within the same year in which the TPP and FCRPS BiOp costs are incurred.

As an offset to the risk of realizing higher than expected net revenues, BPA is also including the DDC, which will refund money to customers in the event BPA's financial reserves exceed the amounts needed to maintain the TPP for all three years of the rate period.

Section 3 of this study describes the CRAC, both the NFB Adjustment and NFB Surcharge, and the DDC.

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 its 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 remains in effect. It was intended to be in effect until replaced, and it has not been replaced.

This 95 percent, two-year TPP standard was translated to an equivalent percentage for three-year rate periods by assuming consecutive rate periods are statistically independent and that the three-year TPP standard should provide the same total probability of making all 6 payments in two three-year periods as would be provided by three two-year periods in each of which the 95 percent TPP standard is met. This target probability is 92.6 percent:

$$.95^3 = .85738$$

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

$$.85738^{1/2} = .92595$$

This figure was rounded to 92.6 percent. To check, calculate the TPP for two consecutive five-year periods:

$$.926^2 = .857$$

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

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

$$.9747^3 = .926$$

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 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 of the Risk Mitigation Package

BPA's policy objectives for the risk mitigation package (*See* WP-07 ROD, WP-07-A-02, Section 2.9 at 5) include the following five objectives:

(1) A rate design that meets BPA financial standards, including meeting a 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.

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

In the Final Study, BPA updated and analyzed its power risks and relied on the following risk tools designed to achieve the 92.6 percent TPP standard for the generation function. The following items are included in the calculation of the TPP.

(1) Liquidity Reserve Level. The liquidity reserve level increased from $50 million to $175 million and then lowered to $88.7 million to account for new sources of liquidity. A deferral of a Treasury payment is registered when reserves fall below this level of Liquidity Reserves attributed to the generation function.

(2) 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, based on the expected value forecast of PBL's FY 2006 2nd Quarter Review, is $895 million. This value of $895 million reflects the removal of the cap on net secondary revenues which was used in the initial proposal.

(3) The Temporary Availability for PBL Rate-Setting of Other Agency Reserves. BPA assumes that any financial reserves attributed to TBL above the level required to satisfy TBL's 95 percent TPP standard for FY 2006–2007 Transmission rate period

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 TBL Reserves are assumed to be available to PBL in FY 2007.

(4) Cost Recovery Adjustment Clause. The CRAC is an upward adjustment to the applicable requirements power rates published in the Final Studies. The adjustment is applied to power deliveries beginning in October following the fiscal year in which PBL's Accumulated Modified Net Revenues (AMNR) fall below the CRAC threshold. The AMNR threshold is set at the equivalent of $750 million in financial reserves attributed to PBL.

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

(6) Planned Net Revenues for Risk. PNRR is the last and final component of the revenue requirement that is added to annual expenses. By increasing the rate calculated from the revenue requirement, PNRR increases rates which in turn increase financial reserves, thus increasing TPP until it meets the 92.6 percent TPP objective. PNRR in the amount of $11 million has been applied equally to each year of the rate period.

Additional tools are also included in BPA's risk mitigation package, but are not modeled as part of the TPP analysis. These tools were not modeled because they are designed to recover the costs directly created by specific uncertainties either in a following fiscal year or in the year that the cost is incurred. Relying on, but not modeling, the NFB mechanisms do not decrease TPP.

(1) <u>[N]ational Marine Fishery Service, [F]ederal Columbia River Power System, [B]iological Opinion Rate Adjustment Mechanism (NFB Adjustment)</u>. This adjustment increases the annual maximum recovery amount (Cap) on the CRAC to allow recovery of increased costs or reduced revenues resulting from court-ordered changes to hydro operations, court-approved settlements over the FCRPS 2004 BiOp and/or any increase in costs due to a new BiOp. The NFB Adjustment does not directly modify rates.

(2) <u>Emergency NFB Surcharge</u>. This surcharge is a separate mechanism from the NFB Adjustment, but it triggers based on the same court-related events with the added requirement that the PBL TPP be less than 80 percent. The NFB Surcharge addresses the fact that the CRAC does not produce revenues in the same fiscal year in which Financial Effects occur. The NFB Surcharge is designed to recover NFB costs (or lost revenues) in the same year when BPA's financial reserves are precariously low.

Information regarding these features is discussed in Section 3 of this study, the WPRDS (WP-07-FS-BPA-05) and the General Rate Schedule Provisions (WP-07-A-02).

2. RISK ANALYSIS

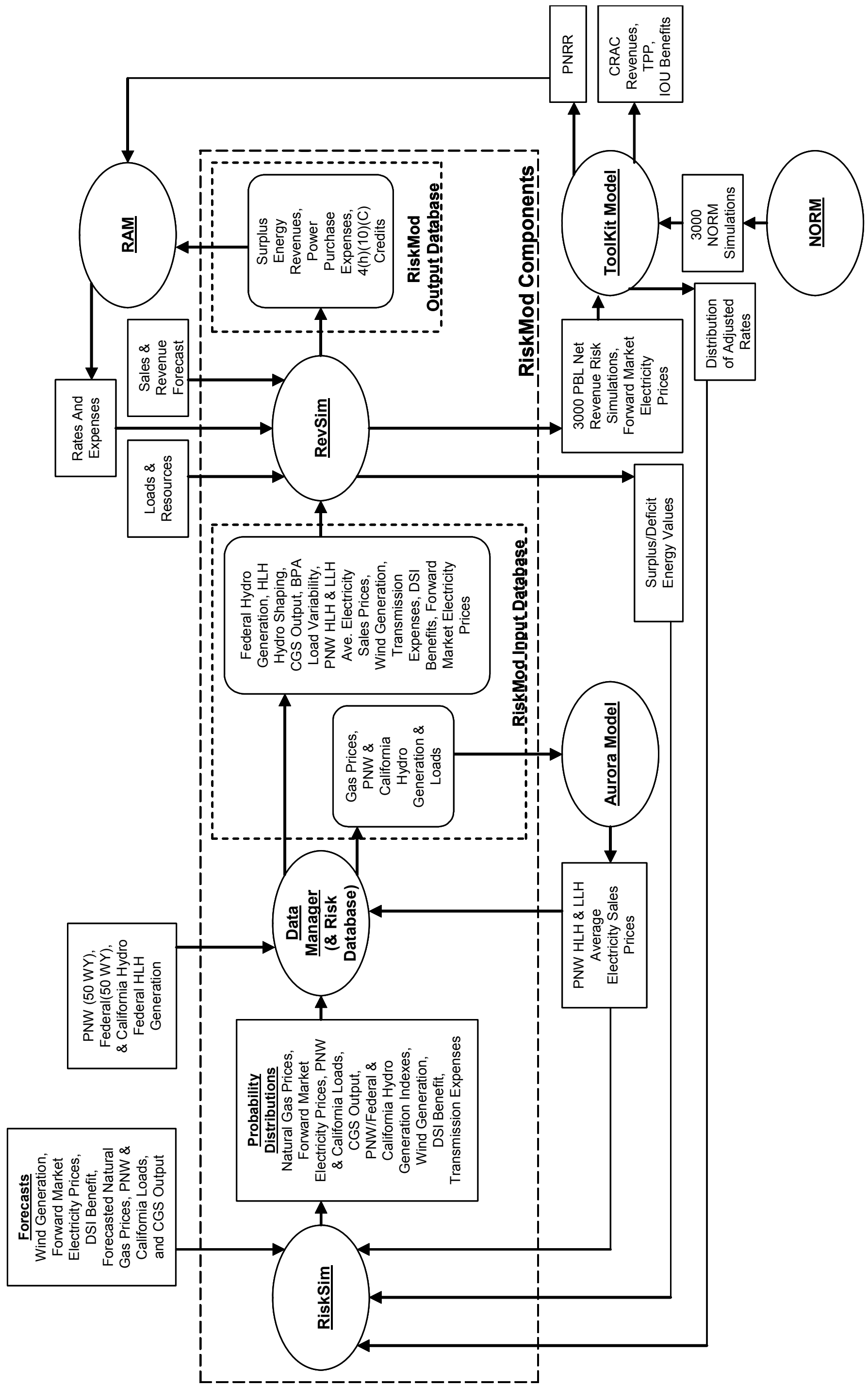
BPA's traditional approach to modeling risks is to use *Monte Carlo* simulation methodology. In this technique, the models RiskMod, NORM, and ToolKit run through 3,000 *games* or scenarios. In each game, each of the financial uncertainties is randomly assigned a value based on input specifications for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

2.1 RiskMod

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

Variations in monthly loads, resources, natural gas prices, forward market electricity prices, transmission expenses, and aluminum smelter benefit payments are simulated in RiskSim. Monthly spot market electricity prices based on simulated loads, resources, and natural gas prices are estimated by AURORA. Data Management Procedures facilitate the formatting and movement of data that flow to and/or from RiskSim, AURORA, and RevSim. RevSim uses risk data from RiskSim, spot market electricity prices from AURORA, loads and resources data from the Load Resource Study, WP-07-FS-BPA-01, various revenues from the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-07-FS-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-FS-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-FS-BPA-05; the Revenue Requirement Study, WP-07-FS-BPA-02; and discussion of AURORA in the Market Price Forecast Study, WP-07-FS-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 HLH and LLH spot market electricity prices. The prices estimated by AURORA are then downloaded into the risk database and a consistent set of loads, resources, and spot market electricity prices are used to calculate net revenues in RevSim.

The risk models run 3,000 games to produce monthly risk data for FY 2007-2009 rate period. Thus, each of the risk models produces 3,000 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 specific risk, providing the necessary parameters required for developing the probability distribution, and letting @RISK sample values from the probability distributions based on the parameters provided. The values sampled from the probability distributions reflect their relative likelihood of occurrence. The parameters required for appropriately capturing risk are not developed in @RISK, but are developed in analyses external to @RISK.

2.4 Operational Risk Factors

In the course of doing business, BPA manages risks that are unique to operating a hydro system as large as the Federal Columbia River Power System (FCRPS). The variation in hydro generation due to the volume of water supply from one year to the next can be substantial. BPA also faces other operational risks and variability that increase BPA's risk exposure, including the following: (1) load variability due to changes in load growth and weather; (2) nuclear plant (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 a new Biological Opinion. There is currently no specific guidance on what the remanded 2004 Bi-Op will contain to incorporate this risk in the Final Studies. However, BPA has incorporated what it believes to be the most likely hydro operations for the rate period absent a new Bi-Op that includes 2006 court-ordered spill operations for FY 2007-2009. Detail of the power and non-power requirements for the hydro regulation study for FY 2007-2009 are presented in the Load Resource Study Documentation, WP-07-FS-BPA-01A, Section 2.9.2 through 2.9.3, at 110-130. 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-FS-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 the Hydro-regulation component of the Load Resource Study, WP-07-FS-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 streamflow 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 using a uniform distribution. 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-FS-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-FS-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-FS-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-FS-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 have on California loads and HLH and LLH spot market electricity prices. The level of economic activity impacts the overall annual amount of loads in California while fluctuations in load due to weather conditions cause monthly variation in loads, especially during the summer when cooling loads are highest. Load growth variability and load variability due to weather for California are simulated in the California Load Risk Model. (*See* Risk Analysis Study Documentation, WP-07-FS-BPA-04A.) Annual load growth variability parameters are derived from historical WECC load data. (*See* Risk Analysis Study Documentation, WP-07-FS-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-FS-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-FS-BPA-04A and Market Price Forecast Study, WP-07-FS-BPA-03.)

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

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

2.4.6 Nuclear Plant Generation Risk Factor

This risk factor is modeled in the Columbia Generating Station (CGS) Nuclear Plant Risk Model and reflects the uncertainty in the amount of energy generated by the CGS. (*See* Risk Analysis

Study Documentation, WP-07-FS-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-FS-BPA-01**.** The potential values of the results simulated can vary from the output capacity of the plant to zero output.

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

2.4.7 IOU Residential Exchange Program (REP) Settlement Benefits Risk Factor

This risk factor reflects the uncertainty in the amount of benefits from the IOU REP Settlement Agreement in FY 2007-2009, relative to the benefits included in the Revenue Requirement when setting rates. (*See* Revenue Requirement Study, WP-07-FS-BPA-02**.)** The quantification of this risk reflects the contract terms set forth in the IOU REP Settlement Agreements entered into in May 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 region's 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. 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-FS-BPA-04A.) Unlike

FY 2008 and FY 2009, annual forward market prices were not simulated for FY 2007, since the deterministic price forecast to be used for computing the FY 2007 IOU REP Settlement benefits was known prior to the final studies.

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 2007-2009, relative to the benefits included in the Revenue Requirement when setting rates. (*See* Revenue Requirement Study, WP-07-FS-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, and the DSI Supplemental Administrator's Record of Decision, signed June 1, 2006, 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. For FY 2008-2009, 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-FS-BPA-04A.) It was assumed, for rate setting purposes, that the deterministic price forecast used for computing the FY 2007 DSI benefits will be the same as for the FY 2007 IOU REP Settlement benefits. Therefore, annual forward market prices were not simulated for FY 2007 since this price was known prior to the final studies.

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-FS-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-FS-BPA-01. The risk of the value of the wind generation is calculated in RevSim and is based on the differences between the purchase prices specified in output contracts that wind generators have with BPA and the wholesale electricity prices at which BPA can sell the amount of variable energy produced. Under its output contracts, BPA only pays for the amount of energy that is produced.

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

2.4.10 Transmission Expense Risk Factor

This risk factor reflects the uncertainty in PBL transmission and ancillary expenses, relative to the expected expenses included in the Revenue Requirement when proposing rates. (*See* Revenue Requirement Study, WP-07-FS-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 probability distributions for these expenses being asymmetrical, since it reflects how transmission and ancillary services expenses vary from the cost of the fixed, take-or-pay, firm transmission capacity that the PBL has under contract, which must be paid regardless of whether or not it is used. Because the PBL has more firm transmission capacity under contract than it has firm contract sales, this phenomenon reflects that the PBL does not incur the costs of purchasing additional transmission capacity until the amounts of surplus energy sales exceed the amounts of residual firm transmission capacity after serving all firm sales. (*See,* Risk Analysis Study Documentation, WP-07-FS-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-FS-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). (*See* Load Resource Study, WP-07-FS-BPA-01). 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-FS-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 associated with the 4(h)(10)(C) credits is contained in the Load Resource Study Documentation, WP-07-FS-BPA-01.

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

2.4.12 RevSim Analysis

The RevSim module within RiskMod serves two main functions in determining rates. The first function (the 50 Water Year Run) is to calculate secondary energy revenues and 4(h)(10)(C) credits that are used by the RAM2007 model. The second function (the Risk Simulation Run) is to simulate PBL's operational net revenue risk. *See* Risk Analysis Study Documentation, WP-07-FS-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-FS-BPA-01, the Revenue Forecast component of the Wholesale Power Rate Development Study, WP-07-FS-BPA-05, and the RAM2007.

The risk data simulated by RiskSim and monthly spot market electricity prices estimated by AURORA are used to calculate 3,000 net revenues in RevSim for 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 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 rates with $11 million in PNRR is reported in Table 1. Net revenues over the rate period average $69 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. Also, the average net revenues in Table 1 will differ from the net revenues shown in Table 8A of the Revenue Requirement Study, WP-07-FS-BPA-02, which represents a deterministic forecast that does not account for the impact of risks.

Table 1: RiskMod Net Revenue Statistics (With PNRR of $11 million)

			(in thousands)
	FY 2007	**FY 2008**	**FY 2009**
Average	117,001	115,556	-25,444
Median	110,492	102,176	-41,982
Standard Deviation	327,010	345,335	370,843
1%	-498,496	-531,371	-876,666
2.50%	-458,161	-458,634	-661,287
5%	-412,332	-407,581	-545,658
10%	-325,920	-328,067	-475,935
15%	-224,485	-248,626	-392,622
20%	-156,871	-177,070	-316,482
25%	-103,933	-117,380	-256,078
30%	-50,914	-69,375	-209,052
35%	-4,864	-22,673	-164,600
40%	33,708	22,958	-123,721
45%	69,986	58,094	-78,976
50%	110,492	102,176	-41,982
55%	145,655	140,136	-4,976
60%	181,910	179,793	36,472
65%	225,268	218,570	81,999
70%	270,580	262,515	132,067
75%	311,678	320,167	180,960
80%	370,002	381,205	240,813
85%	437,112	457,223	321,665
90%	536,058	565,548	429,283
95%	682,241	709,790	594,130
97.50%	817,900	862,209	789,089
99%	963,499	1,048,700	1,065,763

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 except that 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 risks surrounding projections of non-operations related revenue or expense levels associated with the generation function in the revenue requirement. The outputs from NORM, along with the outputs from RiskMod, are 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 3,000 games of both net revenue and cash impacts to the ToolKit.

2.5.1 Methodology

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

2.5.2 Data Gathering and Development of Probability Distributions

To obtain the data used to develop the probability distributions used by NORM, BPA interviewed the subject matter experts (SME) for each capital and expense item modeled. Prior to each interview, the SME were sent a set of questions to think about regarding the risks surrounding the cost estimates included in the final PFR. During the interviews, the SME were asked for their assessment of the risks concerning their cost estimates, including the possible range of outcomes and the associated probabilities of occurrence. In some instances, the SME's were 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 four cost elements:

(1) Base O&M;
(2) Nuclear fuel;
(3) Decommissioning Trust Fund Contributions; and,
(4) NEIL Insurance Premiums.

For this rate case, NORM 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 the final PFR II estimate. The minimum value is the final PFR I cost estimate, and the maximum value is the initial PFR I estimate. The minimum and maximum values are the same as those included in the initial proposal. For NEIL insurance, NORM modeled the uncertainty around the level of the gross premium and the level of earnings on the NEIL fund. Member utilities receive annual distributions based on the level of these earnings, which lowers the premiums they actually pay.

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

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

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

(1) Additional security costs if an event occurs;

(2) Additional fish costs if an event occurs;

(3) Additional system needs;

(4) Additional extraordinary maintenance; and,

(5) Base O&M for 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 II value, and a maximum value equal to the Final PFR II value.

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

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

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

The distributions for Total COE and Reclamation O&M are shown in Table 2 of the documentation. Distributions are shown for each fiscal year for FY 2007-2009, and also for the total of the three years. (*See* Risk Analysis Study Documentation WP-07-FS-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 estimate for FY 2006. For FY 2007-9, NORM uses the discrete probability distributions contained in Table 10 of the documentation. (*See* Risk Analysis Study Documentation WP-07-FS-BPA-04A.)

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 generated by @Risk, which was then truncated at the minimum and maximum values for the 50 historic years. The 50 years of data is provided in Table 12 of the documentation.(*See* Risk Analysis Study Documentation WP-07-FS-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 in Table 3 of the documentation. Distributions are shown for each fiscal year for FY 2007-2009, and also for the total of the three years. Similar graphs for the Spokane Settlement payments are shown in Table 4 of the documentation. (*See* Risk Analysis Study Documentation WP-07-FS-BPA-04A.)

2.5.3.4 Public Residential Exchange

For the Public Residential Exchange, the SME provided the complete probability distribution. The distribution was updated for the final studies. It is contained in Table 5 of the documentation. (*See* Risk Analysis Study Documentation WP-07-FS-BPA-04A.)

2.5.3.5 PBL Transmission Acquisition and Ancillary Services

For Transmission expense, NORM modeled uncertainty around:

(1) Third party GTA wheeling;
(2) Third party Transmission and Ancillary Services; and,
(3) Reserve and other Services.

The uncertainty around PBL purchases of Transmission and Ancillary Services from TBL is modeled in RiskMod.

For Third party GTA wheeling, NORM modeled the uncertainty around the level of future price increases for FY 2007-2009. This distribution was updated for the final studies. For Third 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 in Table 6 of the documentation. Distributions are shown for each fiscal year for FY 2007-2009, and also for the total of the three years. (*See* Risk Analysis Study Documentation WP-07-FS-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; and,

(5) Telemetering Equipment and Replacement.

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

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

(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 three years. Similar graphs for the Lower Snake River Hatcheries expense are shown in Table 9. (*See* Risk Analysis Study Documentation WP-07-FS-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) COE/Reclamation Direct Funded Capital; and,
(5) CGS capital.

The uncertainty modeled relates to both the level of capital expenditures and the interest rate on the bonds or appropriations used to fund the investments. In addition, NORM modeled the uncertainty around the level of interest rates on the bonds used to fund CGS capital investments, and whether the capital costs to replace the CGS condenser tubes would be incurred during FY 2009.

2.5.3.9 Interest Rate and Inflation Risk

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

(1) 30-Year Appropriations;

(2) 30-Year U.S. Treasury Bonds;

(3) 5-Year U.S. Treasury Bonds;

(4) 13 to 15-Year Tax-Exempt Municipal Bonds; and,

(5) 13 to 15-Year Taxable Municipal Bonds.

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

During the customer workshop on NORM, customers commented that NORM lacked correlations between the distributions around interest rates and the inflation rate. BPA has addressed this concern for the final studies. To address the correlations within a given fiscal year, a LOOKUP table has been constructed containing 21 rows of potential interest rates and the corresponding rate of inflation for each year. Row 1 contains the minimum possible values, row 11 contains the median values, and row 21 contains the maximum possible values for each of the interest rates and the inflation rate for that year.

For FY 2007, each of the 21 rows has an equal probability of being selected. For each of the 3,000 games, NORM selects one of the 21 rows, thereby selecting the values in that row for that particular game. For example, if row 8 was chosen for FY 2007, the following interest rates and inflation rate would be used in that game.

- 30-Year Appropriations 5.06%
- 30-Year U.S. Treasury Bonds 5.99%
- 5-Year U.S. Treasury Bonds 5.19%
- 15-Year Tax-Exempt Municipal Bonds 4.48%
- 15-Year Taxable Municipal Bonds 6.02%

- Inflation Rate 1.74%

To address correlations between fiscal years, NORM sets the row number most likely to be chosen for the next fiscal year to be the same as the row number chosen in the current fiscal year. Continuing the example from above, where row 8 was chosen for FY 2007, the most likely row to be chosen in FY 2008 would again be row 8. Rows further removed from row 8 would become increasingly less likely to be chosen, with row 21 being the least likely row to be selected. Similar logic is applied for FY 2009, with the row number chosen for FY 2008 being the most likely row number to be chosen for FY 2009.

The full distributions are in Table 10 of the documentation. (*See* Risk Analysis Study Documentation WP-07-FS-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 change depreciation and amortization expense, and net interest expense. These in turn, affect net revenues. The distributions for Total Federal depreciation, amortization, and net interest are shown in Table 11 of the documentation. Distributions are shown for each fiscal year for FY 2007-2009, and also for the total of the three years. (*See* Risk Analysis Study Documentation WP-07-FS-BPA-04A.)

2.5.3.10.1 Conservation

To model uncertainty around the level of conservation capital expenditures, NORM uses the final PFR II 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 five-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 final PFR II 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 final PFR II 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 COE/Reclamation Direct Funded Capital

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

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

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

For the level of 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 Columbia River Fish Mitigation (CRFM)

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

2.5.3.10.6 CGS Capital

In the initial proposal, NORM modeled the uncertainty around the level of interest rates on the bonds used to fund CGS capital investments. For the final studies, NORM is modeling the interest rate uncertainty, and whether the capital costs to replace the CGS condenser tubes will be incurred during FY 2009, as decided during the PFR II process. To reflect the uncertainty around whether the condenser tubes will need replacing, NORM assumes there is a 100 percent probability that the study costs of approximately $5.5 million will be incurred during FY 2007 and FY 2008, and a 50 percent probability that $29.5 million will be expended during FY 2009 to replace the condenser tubes.

Since the initial proposal, it was decided that CGS debt, both new and refinanced, can be extended through FY 2024. Accordingly, new debt for CGS capital projects is now forecast to mature between FY 2020 and FY 2024. In addition, EN is issuing taxable bonds, as well as tax-exempt bonds. Therefore, NORM now models the uncertainty around both taxable and tax-exempt bonds. For each fiscal year, FY 2007 through 2009, NORM uses the midpoint of the maturities for the bonds forecast to be issued in that year to model the interest rate risk around the new bonds. For FY 2007 the midpoint is 15-year bonds, 14 years for FY 2008, and three years for FY 2009. For example, to calculate uncertainty in interest expense for FY 2007, NORM calculates the interest expense assuming all new debt issued matures in FY 2022 (15-year maturity), using the interest rate selected in that particular game. It then subtracts the interest expense calculated in that game from the new debt interest expense included in the revenue requirement study to get the interest expense delta for that game.

2.5.3.11 Revenues from Generation Supplied Reactive (GSR)

For the Supplemental Proposal, NORM modeled the uncertainty around the level of payments the PBL would receive for GSR services provided to the TBL for FY 2008 and FY 2009. The uncertainty around GSR revenues is being modeled in the same manner for the final studies. For each fiscal year, NORM uses a uniform probability distribution, with a minimum value of $4 million and a maximum value of $20 million. This means any value between $4 million and $20 million is equally likely to be chosen in any particular game.

2.5.3.12 Renewables Facilitation Costs

In the PFR II process, it was decided that the uncertainty around future levels of additional facilitation spending would be modeled in NORM. The expected values were to be $4 million in FY 2007, and $8 million annually for FY 2008-2009. The minimum is $0, and the maximum is $16 million annually per the final PFR II decision. Renewables facilitation costs, along with additional descriptive statistics, are shown in Table 14 of the documentation. Distributions are shown for each fiscal year for FY 2007-2009, and also for the total of the three years. (*See* Risk Analysis Study Documentation WP-07-FS-BPA-04A.)

2.5.3.13 Accrual to Cash (ATC)

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

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 with the new value for each game for the following line items in the table.

(1) Line 1: Depreciation/Amortization
(2) Line 4: Slice True-up included in All Other
(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 the final studies, NORM is assuming a 25 percent probability that debt optimization will not occur, and a 75 percent probability that debt optimization will occur during EN FY 2008 and EN FY 2009. By moving to direct pay for the EN budget, the effect on reserves is significantly smaller from debt optimization than it was under net billing. NORM replaces the deterministic value with the new value for each game for the following line items.

(1) Line 3: EN Direct Pay 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

The September revenue lag is now the same both with and without the debt optimization program. This is because only O&M payments, not debt service, are made in September, and the O&M payment is the same with or without debt optimization. This is the main reason that the effect on reserves is negligible with debt optimization under direct pay.

Table 2
TOOLKIT NET REVENUE TO CASH ADJUSTMENTS
(in $Millions)

		FY 2006	FY 2007	FY 2008	FY 2009
1	Depreciation/Amortization	$178.296	$190.329	$198.774	$206.042
2	Interest Adjustments	($45.937)	($45.937)	($45.937)	($45.937)
3	ENW Direct Pay Prepaid Expense	$330.034	($0.473)	$26.820	($19.082)
4	All Other (see line 14 below)	($106.729)	$42.271	($13.323)	($12.991)
5	**Sub Total Lines 1 - 4**	$355.664	$186.190	$166.334	$128.032
6	Add: EN Debt Service Before Refinancing	$539.804	$495.355	$543.864	$535.079
7	Less: Current Estimated ENW Debt Service (PBL only)	($272.611)	($359.622)	($543.864)	($535.079)
8	Less: Planned Advanced Amortization of Federal Debt	($337.200)	($231.785)	$0.000	$0.000
9	**Sub Total Lines 6 - 8**	($70.007)	($96.052)	$0.000	$0.000
10	Less: Scheduled Federal Debt Amortization	($128.476)	($216.331)	($243.433)	($109.655)
11	Less: Transmission Revenue Financed Capital	$0.000	$0.000	$0.000	$0.000
12	**Sub Total Lines 10 - 11**	$157.181	($126.193)	($77.099)	$18.377
13	**Accrul to Cash Adjustment (Lines 5 + 9 + 12) (Less IOU Deferral Payment in FY 06)**	**$157.181**	**($126.193)**	**($77.099)**	**$18.377**
14	**All Other**				
	Slice & LB CRAC True-up	($16.879)	$60.143	$0.000	$0.000
	NB Revenue and other cash lags	($48.995)	($8.247)	($1.176)	($0.844)
	Terminated contracts & Enron Settlement	($22.470)	($2.978)	($3.524)	($3.524)
	Energy Efficiency Projects	($24.510)	$0.000	$0.000	$0.000
	IOU Deferral Payments	($3.570)	($3.623)	($3.623)	($3.623)
	Inter Company Revenue Net of Expense	$1.314	$0.000	$0.000	$0.000
	Asset Write Down Non - Cash Expense	$0.760	$0.000	$0.000	$0.000
	Residential Exchange Settlement Payment net of booked Expense	$12.300	($2.300)	($5.000)	($5.000)
	Cash Outlays	($4.679)	($0.724)	$0.000	$0.000
	TOTAL All Other	**($106.729)**	**$42.271**	**($13.323)**	**($12.991)**

2.6 Output

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

3. RISK MITIGATION

3.1 Treasury Payment Probability (TPP)

One of BPA's policy objectives for this rate case is to meet its TPP standard. As described in Section 1 of this study, this standard for a three-year rate period is 92.6 percent 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 percent TPP in each two-year rate period. Since FY 2002, the transmission and generation functions have set their rates separately, and BPA has determined that if each function separately meets the TPP standard with their respective rates and the reserves attributed to that business line, the Agency TPP requirement will be met. BPA has calculated that a 92.6 percent TPP for a three-year rate period is equivalent to the two-year 95 percent TPP called for in the 10-Year Financial Plan.

3.2 ToolKit Overview

The ToolKit is an Excel 2003® spreadsheet that PBL uses to evaluate its ability to meet the TPP standard, given the net revenue variability embodied in the distributions of operating and non-operating risks. Many of the settings are entered on the ToolKit main page (the 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. BPA has determined that the amount of liquidity it needs to be supplied by financial reserves is $89 million. The ToolKit is run for 3,000 "games" or scenarios. TPP is calculated by dividing the number of those games where each of the three years in the rate period ends with at least $89 million in PBL reserves by 3,000.

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

3.3 Tools Incorporated into BPA's Final Study

Risk mitigation is a very important part of this rate proposal. The preceding sections of this study described the risks that BPA is modeling explicitly. This section describes the tools for mitigating those risks that BPA has considered. Some of these tools are modeled and included in BPA's rate proposal, others are not modeled, specifically the NFB Adjustment and the NFB

Surcharge, but are included as part of BPA's risk mitigation package. The following sections describe each of these risk mitigation tools.

3.3.1 Tools Modeled in the ToolKit

3.3.1.1 Reserves and PNRR

Reserves. The fundamental protection against the financial impacts of the uncertainty BPA faces is its financial reserves. For this rate case, it is the reserves attributable to the generation function (PBL reserves), with one exception described below, that are considered when measuring TPP. Financial reserves available to the generation function 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 are converted to cash when the borrowing is completed.

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.

PNRR. BPA conducts analyses of its TPP using current 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, then the projected reserves, along with whatever other risk mitigations considered in the analysis, are not sufficient to reach the TPP standard. This is typically corrected by adding PNRR to the revenue requirement as a cost needed to be recovered by rates. This has the effect of increasing rates, which will increase the net cash flow, which will increase the available PBL reserves, and therefore increase TPP.

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

3.3.2 Other Agency Reserves Temporarily Available to PBL

Management directed staff to study whether any agency reserves not attributed to generation could be considered available for helping to mitigate power risks when setting power rates. Staff concluded that such reserves do exist. 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 percent for a two-year rate period. In fact, the TBL TPP was higher than 95 percent because TBL's reserves were actually greater than needed to support the 95 percent 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 concluded that if TBL reserves were $55 million lower than projected in FY 2007, TBL's rates would still meet the TPP standard.

Therefore, staff concluded that $55 million of reserves not attributed to PBL in FY 2007 can be considered to be available for mitigating PBL risks when setting rates for FY 2007-2009.

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 plans that any temporary use of these reserves in FY 2007 is completely made up for in such a way that TBL rates are no higher than if BPA had not made this assumption. If these reserves were assumed to be available to PBL in years other than FY 2007, it would allow for the unacceptable possibility that TBL customers could be subsidizing PBL rates. Therefore, no TBL reserves are considered available in FY 2008 and FY 2009.

3.3.3 The Cost Recovery Adjustment Clause (CRAC)

Cost recovery adjustment clauses, or CRACs, can be very powerful risk mitigation tools. BPA proposed a single CRAC in its May 2000 power rate case. The 2002 Supplemental Proposal, a result of highly effective collaboration between BPA and its power customers, included three distinct CRACs: (1) the Load-Based (LB) CRAC dealt with the financial uncertainty of the augmentation solution; (2) the Financial-Based (FB) CRAC mitigated general financial risks; and (3) the Safety Net (SN) CRAC served as a back-stop against financial risks that could not be handled by the first two CRACs. In this rate case, BPA is returning to a single CRAC.

BPA has employed CRACs or Interim Rate Adjustments (IRAs) as rate adjustment mechanisms that respond to the financial risks BPA faces. Financial reserves were the original metric used for determining whether this mechanism had triggered. BPA decided in the May 2000 Proposal to use accumulated net revenues because net revenues are a more standard financial metric. BPA continues this practice.

3.3.3.1 Basic Description of the CRAC

The CRAC for FY 2007-2009 is similar to the SN CRAC and FB CRAC from the SN-03 rate case, though some differences are noted here. It is an annual upward adjustment in energy and demand charges for rates subject to the CRAC. The CRAC has a limit to the annual collection amount of $300 million. The threshold is an amount of PBL AMNR as accumulated since the end of FY 1999. The AMNR threshold values are calibrated to be equivalent to PBL financial reserve levels of $750 million.

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 year-end AMNR will be made after the 3rd Quarter Review, and then compared to the thresholds for the CRAC and the DDC. If this AMNR forecast is below the CRAC threshold, an upward rate adjustment will be calculated for the duration of the upcoming fiscal year. If the forecast is above the threshold for the DDC, a downward rate adjustment is calculated to distribute dividends to applicable rates for the duration of the upcoming fiscal year.

Table 3: CRAC Annual Thresholds and Caps

[Dollars in Millions]

AMNR Calculated at end of Fiscal Year	**CRAC Applied to Fiscal Year**	**CRAC Threshold***	**Approx. Threshold as Measured in PBL Reserves**	**Maximum CRAC Recovery Amount (CRAC Cap)****
2006	2007	-$151	$750	$300
2007	2008	-$53	$750	$300
2008	2009	-$48	$750	$300

* As measured by AMNR.
** The Maximum CRAC Recovery Amount (CRAC Cap) may be modified to account for adjustments made to the CRAC Cap by the NFB Adjustment (if triggered) calculated at the end of FYs 2006, 2007, and 2008.

3.3.3.2 Differences from the FB CRAC

There are four main differences between the design of the current FB CRAC and that of the CRAC for the FY 2007-2009 rate period:

1. The CRAC applies only to HLH and LLH Energy and Load Variance rates, but not to the Demand rate;
2. The CRAC revenue collection amounts will not be prorated to account for Slice load;
3. The CRAC does not have a true-up feature; and
4. The caps for the CRAC can be adjusted by the NFB Adjustment described in Section 3.4.1.

As with the FB CRAC, the 2007-2009 CRAC uses 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 CRAC has a cap of $300 million for each year of the rate period.

3.3.3.3 Differences from the SN CRAC

There are three main differences between the design of the current SN CRAC and that of the FY CRAC for the 2007-2009 rate period:

1. The CRAC applies to energy and demand rates, but not to the load variance rate;
2. The 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 CRAC can be adjusted by the NFB Adjustment described in Section 3.4.1.

As with the SN CRAC, the FY 2007-2009 CRAC uses AMNR thresholds and annual caps, though the thresholds and caps are different from the SN CRAC. The cap for the SN CRAC was $290 million per year; the proposed CRAC has a cap of $300 million for each year of the rate period.

3.3.3.4 New CRAC Features

Three additional features have been added to the CRAC methodology to account for future changes in BPA's financial situation. These changes fall into two primary categories. The first category is changes to the availability of liquidity that BPA uses to set the liquidity reserve level. This is discussed in Section 3.4.3 of this study. The second change, sometimes referred to as the "may language," allows the Administrator to reduce or eliminate the CRAC if PBL's equivalent three-year TPP of 92.6 percent can be maintained for the remainder of the rate period.

3.3.3.4.1 Administrator's Discretion to Adjust the CRAC

BPA is including in the CRAC methodology a process that allows the Administrator to look ahead to the remaining fiscal years of the rate period and determine whether any or all of the CRAC is needed to help BPA maintain its financial standing. The ability to apply discretion in the CRAC percentage adjustment is firmly tempered by the requirement to maintain the equivalent three-year TPP of 92.6 percent. This requirement protects the TPP from departing from the stated objective but provides for lower rates if BPA does not project that it will need the additional revenues.

3.3.3.4.2 One-Time Recalculation of the CRAC and DDC Thresholds

The actual amount of liquidity available through the Flexible PF Rate Program remains uncertain and cannot be fully relied upon until contracts are completed later this summer. There is a high likelihood of successfully completing contracts shortly after the ROD is published, but prior to the August calculation of the FY 2007 CRAC or DDC. For the purposes of the Final Studies, BPA assumes that there will be $125 million of participation in the Flexible PF Rate Program. Because final contract amendments will not be signed before the final rate calculation, BPA is including a one-time adjustment of the CRAC and DDC Thresholds, in August of 2006, to account for the possibility that less liquidity is generated than was assumed at the time final rates were set. If less liquidity is generated, then the CRAC will be made more likely to trigger through a higher AMNR Threshold and/or the DDC will be made less likely through a higher AMNR trigger. This adjustment ensures that rates are set to maintain the 92.6 percent target after the final enrollment in this program is known. If more liquidity is generated, the Contingent Adjustment described in Section 3.3.4.4.3 will be made.

Rather than propose a contingent mechanism for lower amounts of participation in this program, BPA included several pre-calculated adjustments to the CRAC and DDC Thresholds to show the impact that failure in this program could have on power rates. BPA believes this will encourage customers to complete the final steps necessary to participate in this program.

If a lower amount of Flexible PF Rate is available than was assumed to be available in the WP-07 Final Studies, then the CRAC Thresholds will be adjusted upward to account for the lower amount, after this new amount is rounded down to the nearest $20 million. The CRAC Thresholds will be adjusted to the predetermined levels as specified in Table 3 and 4. The DDC Thresholds remain unchanged because the change in the DDC has a negligible impact on TPP.

Table 4
Adjusted CRAC Thresholds for Reduced Flexible PF Revenues [Dollars in Millions]

Flexible PF Participation	Equiv. Amt. of Reserves	PBL Liq. Liquidity Reserves	CRAC Thresholds			
			Equiv. in Reserves	Thresholds in AMNR 2007	2008	2009
125.0	**86.3**	**88.7**	**750.0**	**-151.2**	**-52.9**	**48.2**
120.0	82.9	92.1	753.0	-148.2	-49.9	51.3
100.0	69.1	105.9	783.0	-118.2	-19.7	81.8
80.0	55.2	119.8	814.0	-87.2	11.7	113.3
60.0	41.4	133.6	832.0	-69.2	30.0	131.6
40.0	27.6	147.4	857.0	-44.2	55.7	156.8
20.0	13.8	161.2	877.0	-24.2	76.4	177.0
0.0	0.0	175.0	905.0	3.8	105.7	205.0

Table 5
Adjusted DDC Thresholds for Reduced Flexible PF Revenues [Dollars in Millions]

Flexible PF Participation	Equiv. Amt. of Reserves	PBL Liq. Liquidity Reserves	DDC Thresholds			
			Equiv. in Reserves	Thresholds in AMNR 2007	2008	2009
125.0	**86.3**	**88.7**	**1,050.0**	**148.8**	**247.1**	**348.2**
120.0	82.9	92.1	1,050.0	148.8	247.1	348.3
100.0	69.1	105.9	1,050.0	148.8	247.3	348.8
80.0	55.2	119.8	1,050.0	148.8	247.7	349.3
60.0	41.4	133.6	1,050.0	148.8	248.0	349.6
40.0	27.6	147.4	1,050.0	148.8	248.7	349.8
20.0	13.8	161.2	1,050.0	148.8	249.4	350.0
0.0	0.0	175.0	1,050.0	148.8	250.7	350.0

3.3.3.4.3 Contingent Mechanism for Additional Liquidity

BPA will recognize additional sources of liquidity, including greater participation in the Flexible PF Rate Program, if and when they become available during the FY 2007-2009 rate period. This additional liquidity would allow the amount of reserves set aside for liquidity needs to be reduced, and some amount of reserves to be freed up to increase TPP. The CRAC methodology includes a discretionary, contingent mechanism that allows the Administrator to adjust the CRAC and/or DDC Thresholds if additional or new sources of liquidity become available after the Final Studies are completed. This results in a reduction in the cost of risk in the form of a changes to the CRAC and/or DDC Thresholds, such that the CRAC may trigger less often and for smaller amounts, and the DDC may trigger more often and for larger amounts.

3.3.4 Dividend Distribution Clause (DDC)

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

Table 6: DDC Thresholds

[Dollars in Millions]

AMNR Calculated at End of Fiscal Year	DDC Applied to Fiscal Year	DDC Threshold*	Approx. Threshold as Measured in PBL Reserves
2006	2007	$149	$1,050
2007	2008	$247	$1,050
2008	2009	$348	$1,050

* As measured by AMNR.

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

1. The DDC applies only to HLH and LLH Energy and Load Variance rates, but not the Demand rate; and
2. The DDC is capped, and will not reduce the average annual LLH energy rate to less than $1 per mills/KWh.

Both DDCs use AMNR thresholds, although the threshold values are different. The WP-02 DDC thresholds, measured in AMNR, were 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 DDC AMNR thresholds for FY 2007-2009 are designed to trigger at the equivalent of $1,050 million in PBL reserves for each year.

3.4 Tools Not Modeled in the ToolKit

3.4.1 NFB Adjustment

Fish cost 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 the likely approach to fish recovery and the associated costs to include in the rates for FY 2007-2009. In the May 2000 Proposal, the uncertainty over the financial impacts of future fish measures was reflected by a set of 13 distinct alternatives for fish and wildlife. No such set of alternatives exists for 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 at this time, 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 protects the financial viability of BPA and its financial 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 Cap for any year in the rate period if unforeseen fish and wildlife costs in the previous year arise from a predetermined set of circumstances. The NFB Adjustment calculation results in an increase in the annual CRAC maximum recovery amount for the 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 modified net revenue for FY 2006-2008.

The NFB Adjustment will "trigger" if one of the following four kinds of events arises and results in changes to BPA's FCRPS ESA obligations compared to those in the Final Studies of the WP-07 BPA rate proceeding as modified prior to this Trigger Event:

(1) A court order in *National Wildlife Federation vs. National Marine Fisheries*, CV 01-640-RE, or any appeal thereof ("Litigation");

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

(3) A new NMFS FCRPS BiOp; or

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

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 adjustment to rates because BPA's financial situation was able to cover the increased costs. On the other hand, if AMNR is below the threshold, the NFB Adjustment will allow BPA to recover more than the $300 million Cap if such amounts are needed.

There can be multiple triggering events in any year that are included in the analysis of financial impacts even though there is only one final analysis per year of the total financial impacts due to triggering events that will adjust rates. For example, there could be more than one court order in

FY 2007 that increases the financial impacts of operations in FY 2007. Both of these triggering events would be included in the calculation of the single NFB adjustment that would increase the Cap on the CRAC collection during FY 2008. There can be only one NFB Adjustment for each year 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, as modified prior to a Trigger Event, it is possible for a Trigger Event to affect operations for more than one year of the rate period. For example, a decision in FY 2006 may affect operations in FY 2007 and FY 2008. The analysis of the total financial impact during FY 2006 for adjusting the Cap on the CRAC applying to FY 2007 would be separate from the analysis 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 because 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.

As a result of the Partial Resolution of Issues in the rate case, BPA and parties agreed that the revenues above $300 million resulting from the NFB Adjustment to the Cap should be collected over a different revenue basis than the CRAC. The CRAC revenue basis (before the NFB Adjustment Calculation) is applied to LLH and HLH energy and Load Variance sales. The revenues needed in excess of the amounts recoverable from the CRAC Cap as shown in Table 3, will be collected from LLH and HLH energy, Load Variance and Demand sales proportionally under the firm power rate schedules subject to the CRAC. As a result, revenue recoverable for the financial impacts of the NFB Adjustment are spread over a larger basis than the CRAC, thus lowering the percentage adjustment to the rates. This difference produces a complexity in the CRAC adjustment in that it will require two percentages to be applied to applicable rates if the

NFB Adjustment triggers in a year that the CRAC is greater than the original Cap amount of $300 million.

3.4.2 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 that 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 financial 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 FY 2010-2011, presumably required due to emergency conditions, would be expeditious, there are no special provisions in the WP-07 GRSPs to speed up that process.

3.4.3 Liquidity Tools

During the WP-07 rate case, BPA and customers have worked on a number of liquidity tools, with the objective of including in the Final Studies those tools that could be counted on reliably. This would allow BPA to lower the liquidity reserve level used in the ToolKit as part of the TPP calculation process, which would have the effect of freeing up some reserves for TPP support that would otherwise had to have been kept on hand at the end of each fiscal year to provide liquidity through the next year. This additional TPP support allows the amount of PNRR to be lowered, which reduces the base rates. BPA has successfully obtained the direct payment of EN obligations and the Flexible PF Rate Program.

Two other liquidity tools were originally considered but did not materialize, and are not yet considered reasonably likely to become available. However, it is possible that other sources of liquidity may become available after Final Studies are completed. If this occurs, the Administrator may adjust the CRAC or DDC Thresholds through a discretionary Contingent Mechanism discussed in Section 3.3.4.4.3 of this study.

3.4.3.1 Direct Pay of EN Budget

Many of BPA's public customers were, until FY 2006, actively participating 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 in July. This arrangement resulted in EN's receiving more cash than it needs early in its fiscal year. This surplus was often as large as a couple hundred million dollars by September 30, leaving BPA relatively low on cash when it needs to make its year-end payment to the Treasury.

BPA incorporated the ability to directly pay EN obligations into the calculation of rates in the Final Studies. The critical element to implementing the Direct Pay option was whether BPA's change to a Direct Pay mechanism would affect the tax exempt nature of the bonds. On March 6, 2006, BPA received a Letter Ruling from the IRS indicating that the proposed change did not negatively affect the tax exempt nature of the bonds. This decision paved the way for BPA to enter into agreements with EN to begin directly paying their obligations. This does not retire the Net Billing program, but simply provides for alternative means for meeting EN's obligations. If, in the event EN obligations are not met through the Direct Pay program, the Net Billing program will be reinstituted to meet whatever EN obligations remain.

Because of the IRS ruling, BPA can reasonably rely upon the availability of this liquidity tool and incorporated the impacts in its calculation of rates in the Final Studies. BPA also is modifying its liquidity reserve level to manage the ramifications of Direct Pay on BPA's cash position within the fiscal year, because Direct Pay changes the shape of BPA's cash flow. See Section 3.4.3.4 for further discussion on this issue.

3.4.3.2 Flexible PF Rate Program

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

3.4.3.3 Additional Liquidity Tools

BPA is pursuing a third potential liquidity tool with the U.S. Treasury. If BPA and the U.S. Treasury reach agreement, prior to the implementation of an FY 2009 CRAC or DDC, the risk-reduction benefits may be incorporated through the contingent recalculation of the CRAC and DDC Thresholds described in Section 3.3.4.4.3 of this study.

The fourth liquidity tool originally considered, delaying advance amortization payments from September 30 to sometime early in the next fiscal year, has been rendered irrelevant by the change from Net Billing to Direct Pay – it would have provided additional liquidity only at the beginning of BPA's fiscal year, and under Direct Pay BPA's greatest need for liquidity is in the middle of the fiscal year, not the beginning.

3.4.3.4 The Net Impact on the Liquidity Reserve Level

Both Direct Pay and the Flexible PF Rate Program affect PBL's liquidity reserve level. Under Net Billing, EN received most of its funding for a whole year in the first three months of its fiscal year, which are the last three months of BPA's fiscal year. As a result, when BPA began a fiscal year, EN had over $200 million more cash than it needed at that time (though it would need that money in the coming months). Later, as the Net Billing obligations for that year were completed, this money was in effect returned to BPA, as payments to EN dropped to nearly nothing, and BPA therefore received an influx of cash. Under Direct Pay, the money that would otherwise have been building up at EN at the end of BPA's fiscal year becomes available for making BPA's year-end Treasury payment, which increases TPP and allows PNRR, and therefore rates, to be lowered.

However, the influx of cash in the spring under Net Billing no longer occurs, and BPA needs to have more liquidity reserves, that is, more financial reserves have to be set aside at the beginning of each fiscal year to provide liquidity throughout the next fiscal year. BPA has calculated that, instead of $50 million of liquidity reserves under Net Billing, PBL needs to maintain $175 million of liquidity reserves under Direct Pay (absent other sources of incremental liquidity). These two impacts of Direct Pay are not of equal size. The net effect of 1) the freeing up of money otherwise held by EN, and 2) needing larger liquidity reserves, is a substantial rate reduction while preserving sufficient liquidity.

The Flexible PF Rate Program provides an alternative source of liquidity, and allows PBL's liquidity reserve level to be lower that what it would otherwise need to be under Direct Pay. As a result, the amount of PNRR can be reduced, and/or the CRAC and DDC Thresholds can be lowered. Either option produces lower rates either through a lower base rate or a lower effective rate (the rate after a CRAC or DDC has been applied). The lower expected revenues do tend to slightly increase the need for other sources of liquidity, but as with Direct Pay, the need for slightly more liquidity reserves is more than offset by the rate reduction.

BPA compared two scenarios to determine the magnitude of the liquidity benefit of the Flexible PF Rate Program. In one, BPA set the PBL liquidity reserve level at $175 million. In the other, BPA assumed that PBL liquidity reserves were reduced by $125 million to $50 million and that rates were correspondingly reduced, decreasing the amount of liquidity available from power revenues. Then the level of participation in the Flexible PF Rate Program was varied until the same level of liquidity protection was obtained as in the first scenario. This matching participation level was $181 million. BPA reasons that the relationship between participation in the Flexible PF Rate Program and the concomitant rate reduction and the reduction in need for liquidity reserves is linear. Therefore, for any level of participation in the Flexible PF Rate Program, PBL's liquidity reserve level can be reduced by 69.06 percent of that level (*i.e.*, 125 / 181 x 100) when the impact of the rate reduction is taken into account. However, the liquidity reserve level cannot prudently be reduced below $50 million by reliance on the Flexible PF Rate Program for several reasons. First, the program has not yet been tested, and second, the lead time for obtaining liquidity (cash) through the program could be substantial, meaning that its not as liquid as cash available in the Bonneville Fund.

3.5 ToolKit Modification/Changes in TPP Modeling

Rates in the FY 2007-2009 rate period will be different from those in the period covered by the SN-03 rate case (the SN CRAC rate case) for several reasons. These changes need to be reflected in BPA's TPP calculations and in the tools used to perform those calculations. The CRAC for FY 2007-2009 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. The feature that allows the ToolKit to model PNRR amounts that are different for each year in a rate period has been disabled in order to more accurately calculate the PF rate and maximize the congruence between how rates are calculated in the RAM2007 and how this is simulated in the ToolKit. These and other changes are described in following sections.

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

The three specific CRACs from the SN-03 rate case will no longer be part of BPA's rates after FY 2006. The ToolKit has been changed accordingly. In addition, there are features of the ToolKit that were added during the deliberations leading to BPA's SN-03 proposal but 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

Following the publication of the initial proposal, the parties negotiated a Partial Resolution of Issues which included removal of to the credit for Operating and Regulating Reserves. Therefore, this credit is no longer applicable and removed from ToolKit.

3.5.3 Incorporating the IOU REP Settlement Benefits

One of the most significant developments, as measured by the number of adjustments that had to be made since the last power rate case is the IOU REP Settlement. Under the IOU REP Settlement, the IOUs will receive benefits for FY 2007-2011 based on the difference between an estimate of the future market price and BPA's lowest-cost PF block 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. BPA's rate proposal does not contain a secondary revenue rebate, so this feature is not used.

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, resulting in higher interest credits earned on reserves. This serves to offset expenses and increases net revenues. 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 needs to recover only 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 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 approximates the impact of PNRR on interest credit, for this step in the analysis.

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 sets power rates to be constant across the years: Therefore, although the impact on net revenues varies from year to year due to the anticipation of increasing impacts of interest credits, BPA levelizes this effect when computing the revised rates, for the rate period.

The revised rates are then passed to RiskMod, which simulates 3,000 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 approximates the total change in net revenue that will result from a change in PNRR in order to calculate the resulting change in TPP. The most basic change is that PF rates will increase 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 or 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 are needed – the flat-block PF rate, and the average PF rate (total PF revenues divided by total PF load). 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 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 for the rate case, and therefore is know. Assumptions have to be made about the market rate for FY 2008 and FY 2009 at the time the final 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 from RAM2007). 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 by Slice rates.

3.5.3.3 CRAC Impacts

After the change in the IOU REP Settlement benefits in the year just starting due to the update in the forward-block market price are 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 increase 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 through the PF rate. 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 percent of the IOU REP Settlement benefits, only 77.4 percent of any reduction in IOU REP Settlement benefits contributes to the collection of the CRAC amount.

The forward block market price is compared to a flat-block PF rate. 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

Regular PF = other than Slice

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

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

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

IouDelCon = the final change (delta) in IOU REP Settlement benefits after accounting for 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 Reg PF revenues divided by total Reg 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 = Reg PF load in aMW

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) * IouLoa*H , by Settlement.
2. Iou = Mkt * IouLoa*H – PfFla * IouLoa*H
3. Iou = Mkt * IouLoa*H – (PfAve – PfDif) * 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 + PfCraUnc / PfLoa*H) * IouLoa*H
5. Iou – IouDelUnc = Mkt * IouLoa*H – (PfAve – PfDif) * 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. $-\text{IouDelUnc} = -\text{PfCraUnc} * \text{IouLoa*H} / \text{PfLoa*H}$, or

7. $\text{IouDelUnc} = \text{PfCraUnc} * \text{IouLoa*H} / \text{PfLoa*H}$

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

8. $\text{IouDelUnc} = (\text{Cra} - .774 * \text{IouDelUnc}) * \text{IouLoa*H} / \text{PfLoa*H}$

9. $\text{IouDelUnc} = \text{Cra} * \text{IouLoa*H} / \text{PfLoa*H} - .774 * \text{IouDelUnc} * \text{IouLoa*H} / \text{PfLoa*H}$

10. $\text{IouDelUnc} + .774 * \text{IouDelUnc} * \text{IouLoa*H} / \text{PfLoa*H} = \text{Cra} * \text{IouLoa*H} / \text{PfLoa*H}$

11. $\text{IouDelUnc} * \text{PfLoa*H} + .774 * \text{IouDelUnc} * \text{IouLoa*H} = \text{Cra} * \text{IouLoa*H}$

12. $\text{IouDelUnc} * (\text{PfLoa*H} + .774 * \text{IouLoa*H}) = \text{Cra} * \text{IouLoa*H}$

13. $\text{IouDelUnc} = \text{Cra} * \text{IouLoa*H} / (\text{PfLoa*H} + .774 * \text{IouLoa*H})$

14. $\text{IouDelUnc} = \text{Cra} * \text{IouLoa} / (\text{PfLoa} + .774 * \text{IouLoa})$

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

15. $\text{IouCraUnc} = .774 * \text{IouDelUnc}$

16. $\text{IouCraUnc} = \text{Cra} * .774 * \text{IouLoa} / (\text{PfLoa} + .774 * \text{IouLoa})$

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 raises 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) * 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) + PfRatHeaRoo) * IouLoa*H
21. Iou = (Mkt – (PfAve – PfDif)) * 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 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 and demand components of the flat block rate). This causes 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 percent 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 percent 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 Impacts

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 the DDC threshold is above the CRAC threshold. 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 as large as to reduce the LLH energy rate below $1 per MWh.

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. 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) minimum liquidity reserves, 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 a previous rate case, BPA developed a “new” type of Treasury deferral logic. It is not used in this rate case.

Closer examination of the probable timing of events, as modeled in the traditional logic, prompted BPA to develop a third way of modeling U.S. Treasury deferrals (labeled "Hybrid" on the ToolKit's main page). Consider the current situation. The Final Studies are being run in FY 2006. Suppose FY 2006 turns out to be 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 had already 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 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 repayment 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 track the balance of payments that have been deferred, 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 ends a fiscal year with more than $100 million above its minimum liquidity level. The PBL minimum liquidity level in this proposal is $89 million (See section 3.5.4), so BPA is modeling the repayment as occurring as soon as possible while not bringing the level of PBL reserves below $89 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 was changed between the FY 2002-2006 rate period and the FY 2007-2009 rate period. Since BPA is proposing a change, this feature is used to model a liquidity reserve level of $50 million for FY 2006 and $89 million for FY 2007-2009.

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 comparison of 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 3,000 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 3,000 games). The max-min lines on the reserves chart never go below $89 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 3,000 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 (total nonS \$ / total nonS MWh). This rate has not had the CRD 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 3,000 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;
- 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

3.6 ToolKit Inputs and Assumptions

3.6.1 Inputs and Assumptions on the ToolKit Main Page

3.6.1.1 Risk Analysis Model (RiskMod)

Separate RiskMod runs were made to develop distributions for FY 2005-2006 and the 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.

3.6.1.2 Non-Operating Risk Model (NORM)

A NORM distribution was created for the FY 2007-2009 rate period that reflects the uncertainty around non-operating expenses. (*See* Risk Analysis Study Documentation, WP-07-FS-BPA-4A.)

3.6.1.3 Starting Reserves

The 3,000 FY 2007 starting reserve values have an expected value of $895 million based upon the FY 2006 Second Quarter Review forecast. This results from a starting FY 2006 known value of $375 million and the simulation of the remainder of FY 2006.

3.6.1.4 Starting AMNR

The 3,000 FY 2007 starting AMNR values have an expected value of -$6 million based upon the FY 2006 Second Quarter Review forecast. This results from a starting FY 2006 known value of -$369 million and the simulation of the remainder of FY 2006.

3.6.1.5 Treatment of U.S. Treasury Deferrals

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

3.6.1.6 Other Agency Reserves Temporarily Available

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 4.88 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 $54.0 million, $53.9 million, and $54.9 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. The ToolKit calculates interest earned on reserves by making the simplifying assumption that reserves change linearly from the beginning of the year to the end. It takes the average of the starting reserves and the ending reserves and multiplies that figure by the interest rate for that year. Because PBL's cash payments to the Treasury are not evenly spread throughout the year, but instead are heavier in September, PBL will typically earn more interest in BPA's monthly calculations than the straight-line method yields. The cash timing adjustment is a number from the repayment study that approximates this additional interest credit earned on reserves throughout the fiscal year. The cash timing adjustments for this proposal are $11.9 million, $7.1 million, and $7.4 million for FY 2007, FY 2008, and FY 2009 respectively.

3.6.1.10 Other Cash Adjustments

There are no adjustments of this type. The adjustments that were incorporated into the initial proposal via these cells have been incorporated into the revenue requirement in the Final Studies.

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 $58.46, $50.87, and $50.68 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), 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 $27.33 per MWh for all three years; the pre-ToolKit flat block rate is $25.88 per MWh for all three years. The forecasts of PF loads subject to the CRAC and DDC (this excludes Slice sales and Pre-Subscription sales) are 5,371 aMW, 5,374 aMW, and 5,434 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 CRAC Cap of $300 million.

3.6.2.4 Flat PNRR Rate Impact & PNRR Shape

The "Flat PNRR Rate Impact" assumption was made in ToolKit to match the rate-making logic of the Rates Analysis Model. The cells for the shaping factors reflect this by having the number 1 entered into each of the cells corresponding to FY 2007, FY 2008, and FY 2009.

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