2002 Supplemental Power Rate Proposal
Final Study

WP-02-FS-BPA-09

June 2001

2002 SUPPLEMENTAL POWER RATE PROPOSAL
FINAL STUDY
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ACRONYM LIST

AAC	Adjusted Augmentation Costs
AAP	Acquisition Pre-Purchases
AAMT	Augmentation Amount
AANR	Audited Accumulated Net Revenues
ACA	Augmentation Cost Adjustment
ACTUALLBCREVREQ(NS)	Actual Load-Based Cost Recovery Adjustment Clause (non-Slice)
ACTUALLBCREVREQ(S)	Actual Load-Based Cost Recovery Adjustment Clause (Slice)
AE	Account Executive
AER	Actual Energy Regulation
aMW	Average Megawatt
Amended Proposal	Amended Proposal to the 2002 Power Rate Case (filed 12/12/2000)
ANR	Accumulated Net Revenues
ANRT	Accumulated Net Revenue Threshold
APP	Augmentation Pre-Purchase
APS	Ancillary Products and Services (rate)
APS-S	Actual Partial Service-Simple
ASC	Average System Cost
Avista	Avista Corp
BAC	Baseline Augmentation Cost
BPA	Bonneville Power Administration
Btu	British Thermal Unit
C&R Discount	Conservation and Renewables Discount
CalPX	California Power Exchange
Cfs	cubic feet per second
COB	California-Oregon Border
CRAC	Cost Recovery Adjustment Clause
DDC	Dividend Distribution Clause
DIURNALAC	Diurnal Augmentation cost
DJ	Dow Jones
DSIs	Direct Service Industrial Customers
EPBA	Eastern Power Business Area
FB CRAC	Financial-Based Cost Recovery Adjustment Clause
FBS	Federal Base System
FCCF	Fish Cost Contingency Fund
FCRPS	Federal Columbia River Power System
FERC	Federal Energy Regulatory Commission
FPS	Firm Power Products and Services (rate)
FY	Fiscal Year (Oct-Sep)
GRSPs	General Rate Schedule Provisions
HLH	Heavy Load Hour
IP	Industrial Firm Power (rate)
IPTAC	Industrial Firm Power Targeted Adjustment Charge
IOUs	Investor-Owned Utilities
kcfs	kilo (thousands) of cubic feet per second
ksfd	thousand second foot day

kV	Kilovolt (1,000 volts)
kW	Kilowatt (1,000 watts)
kWh	Kilowatthour
LB CRAC	Load-Based Cost Recovery Adjustment Clause
LBCREVREC	Revenues Actually Received by BPA from the LB CRAC
LDD	Low Density Discount
LLH	Light Load Hour
LOAD	Load subject to LB CRAC
m/kWh	Mills per kilowatthour
May Proposal	May 2000 Final Power Rate Proposal
May ROD	2002 Power Rate Proposal Administrator's Final Record of Decision, WP-02-A-02
MARR	Monthly Augmentation Resale Revenues
MCA	Marginal Cost Analysis
Mid-C	Mid-Columbia
MMBTU	Million British Thermal Units
MOA	Memorandum of Agreement
MW	Megawatt (1 million watts)
MWh	Megawatthour
NAC	Net Augmentation Cost
NACDIFF	Difference in Net Augmentation Cost
NAAC	Net Adjusted Augmentation Costs
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Council
NORM	Non-Operating Risk Model
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
OC	Option Cost
PBL	Power Business Line
PF	Priority Firm Power (rate)
PWF	Power Factor
PMDAM	Power Marketing Decision Analysis Model
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
PRICE	Price for Augmentation not Pre-purchased
Principles	Fish and Wildlife Funding Principles
RATE	Rate without LB CRAC applied
REP	Residential Exchange Program
REP Settlement	Investor-Owned Utilities Residential Exchange Program Settlement
REVRATE	Adjusted Rate
REVw/LBC(S)	Actual Revenues (Slice) to BPA on loads subject to LB CRAC
REVw/LBC(NS)	Actual Revenues (non-Slice) to BPA on loads subject to LB CRAC
REVw/oLBC(S)	Baseline Revenues (Slice) revenue to BPA on loads subject to LB CRAC before application of LB CRAC

REVw/oLBC(NS)	Baseline Revenues (non-Slice) revenue to BPA on loads subject to LB CRAC before application of LB CRAC
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model
RL	Residential Load (rate)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
SACA	Slice Augmentation Cost Analysis
SALESMAYAUG	Sales of Existing Augmentation Quantity
SALENEWAUG	Sales of New Augmentation Quantity
Slice	Slice of the System product
SN CRAC	Safety-Net Cost Recovery Adjustment Clause
STREAM	Short-Term Evaluation and Analysis Model
Supplemental Proposal	Supplemental Proposal to the 2002 Power Rate Case (filed 2/15/2001)
TAAC	Total Adjusted Augmentation Costs
TAC	Targeted Adjustment Charge
TAUGC	Total Augmentation Cost
TARR	Total Augmentation Resale Revenue
TCAAP	Total Cost of Acquisition Pre-Purchases
TPP	Treasury Payment Probability
TPPA	Total Pre-Purchase Cost
TREVw/LBC	Total Revenues with LB CRAC
TREVw/oLBC	Total Revenues without LB CRAC
WPBA	Western Power Business Area
WSCC	Western Systems Coordinating Council

CHAPTER 1: OVERVIEW

1.1 Background

1.1.1 Development of 2002 Wholesale Power Rates. On May 15, 2000, Bonneville Power Administration (BPA) published its 2002 Final Power Rate Proposal (May Proposal), the Administrator's Final Record of Decision for BPA's 2002 Wholesale Power Rates (May ROD) concluding the section 7(i) proceeding to develop Wholesale Power Rates, and associated General Rate Schedule Provisions (GRSPs), for Fiscal Years (FY) 2002–2006. On July 6, 2000, BPA submitted for filing to the Federal Energy Regulatory Commission (FERC) the proposed rate adjustments for its Wholesale Power Rates pursuant to section 7(a)(2) of the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act). 16 U.S.C. §839(a)(2). On August 4, 2000, BPA filed a motion with FERC requesting that FERC stay for 30 days any determination regarding the adequacy of the rate filing. This motion was precipitated by events in the wholesale power market, which resulted in unacceptable financial risks to BPA if FERC approved BPA's rate proposal as submitted. As described below, these rates were developed to implement the goals adopted by BPA in the Subscription Strategy. The rates included risk mitigation tools to deal with the many uncertainties facing BPA and the region over the 2002-2006 rate period. It is now clear that the risk mitigation package contained in the May Proposal is not sufficient to deal with those risks.

On December 12, 2000, BPA filed its 2002 Amended Power Rate Proposal (Amended Proposal). The Amended Proposal contained a three-phase Cost Recovery Adjustment Clause (CRAC) that was designed to address the increased load and higher and more volatile market that BPA was facing. Subsequent to the filing of the Amended Proposal, several significant events occurred that caused BPA to file its 2002 Supplemental Power Rate Proposal (Supplemental Proposal). The market price forecast for the rate period and the forecasted level of BPA's reserves at the start of the rate period both changed dramatically after the filing of the Amended Proposal. These forecasts have been updated in the Study for the 2002 Supplemental Power Rate Proposal (Final Study for the Supplemental Proposal). These updates normally do not produce a material impact on the rate levels. However, as described in the testimony of Conger, *et al*., WP-02-E-BPA-71, the market price forecast of $48.37/megawatthour (MWh) in the Amended Proposal rose to a range of $200-$240/MWh in FY 2002 and declined to a range of $40-$60/MWh in FY 2006 by the time the Supplemental Proposal was filed. Similarly the expected value of BPA's starting reserves at the beginning of the rate period has declined from $929 million forecasted in the Amended Proposal to $309 million. In addition, BPA and the Parties engaged in a series of settlement discussions in an attempt to resolve most of the issues in this proceeding. As a result of these discussions, BPA, together with virtually all of the rate case parties that represent nearly all of the individual public utility customers, most of the Investor-Owned Utilities (IOUs), and every state utility commission, reached an agreement (Partial Stipulation and Settlement Agreement) regarding how BPA should address the cost recovery problem it faces. As a consequence, BPA filed the Supplemental Proposal to incorporate the Partial Stipulation and Settlement Agreement reached between the parties and to address the dramatic changes in the market price forecast and reserve levels.

1.1.2 The Nature of the Problem. BPA's proposed amendments to the GRSPs are necessary because market prices are expected to be much higher and more volatile than assumed in the May Proposal and Amended Proposal. BPA's cost-based rates are now further below market price expectations for the FY 2002-2006 rate period than was the case in the May Proposal.

As a result of higher and more volatile market prices, BPA expects much greater demand for service from customers than was forecasted in the May Proposal. BPA is required to serve this load even though it exceeds the generating capability of the Federal Columbia River Power

System (FCRPS). BPA expects loads will exceed the May Proposal forecast by an additional 1,518 average megawatts (aMW). To meet this increased load obligation, BPA will need to make substantially greater power purchases (augmentation purchases) in the market at substantially higher and more uncertain prices than anticipated in the May Proposal. Moreover, the difficulty of forecasting the expense of serving the increased load obligations is magnified by the fact that prices have escalated in an extraordinarily volatile market, and load response to these higher market prices has increased the uncertainty BPA faces.

Absent a change, Treasury Payment Probability (TPP) would be significantly reduced. By law, BPA's payments to Treasury are the lowest priority of revenue application, meaning that such payments are the first to be missed if reserves are insufficient to pay all bills on time. For this reason, BPA expresses its cost recovery goal in terms of probability of being able to make all Treasury payments during the rate period in full and on time. A TPP that is too low reflects an unacceptable degree of financial risk for BPA and the Treasury. The load obligations that BPA expects to meet through market purchases in a currently escalating and volatile market environment have decreased TPP to just such an unacceptable level.

As in the May and Amended Proposals, the Supplemental Proposal continues to implement the Fish and Wildlife Funding Principles (Principles). WP-02-E-BPA-13, at 7. Among other provisions, the Principles call for a TPP goal of 88 percent and an acceptable range of 80-88 percent for the five-year, 2002-2006 rate period. The rates and risk mitigation tools were initially developed to achieve the TPP goal of 88 percent in full. After the Amended Proposal, increases in uncertainty surrounding augmentation purchase costs, as stated earlier, drove the TPP estimate to below 80 percent.

1.2 Developing a Solution

The Supplemental Proposal deals with this cost recovery problem by amending certain risk mitigation tools contained in the 2002 GRSPs, which apply to the base rates. This approach is a reliable and prudent means of assuring cost recovery while maintaining the basic underpinnings of BPA's Subscription Strategy for marketing power in the coming rate period. The parties to the Partial Stipulation and Settlement Agreement also support the changes outlined in the Supplemental Proposal as an acceptable means of solving the cost recovery problem outlined in the Amended Proposal and in Section 1.1.2.

1.2.1 Implementing Subscription Goals. The May Proposal was designed to implement the decisions made in BPA's Subscription Strategy. The Subscription Strategy was the result of a lengthy three-year public process that began with the Comprehensive Regional Review. The Subscription Strategy was fundamentally a blueprint for how BPA should go about filling the void that would be left after the vast majority of its contracts expired in 2001. The Subscription Strategy provided a structure around which BPA could offer new contracts and meet its statutory obligations while responding to a deregulated wholesale power market and the myriad of changes that had occurred since enactment of the Northwest Power Act.

Changes in the utility environment due to deregulation of the wholesale power market that began in the 1990s forced BPA to become more competitive and to unbundle its power products consistent with the open access to transmission and the more competitive climate in the wholesale power markets. The Subscription Strategy also mapped out a general plan for how the benefits of the FCRPS would be distributed in this new climate, consistent with the requirements and obligations created by the Northwest Power Act. In part, this meant attempting to strike a delicate balance among a wide range of competing interests, including customer groups, governmental entities, tribal representatives, and public interest groups.

In sum, the Subscription Strategy reflected the varied and complex interests in the Pacific Northwest and laid the groundwork for an equitable distribution of the benefits of the FCRPS consistent with legal requirements. The goals of the four principles of the Subscription Strategy are:

- Promote the spread of the benefits of the FCRPS as broadly as possible, with special attention given to the residential and rural customers of the region.
- Avoid rate increases through a creative and business-like response to markets and additional aggressive cost reductions.
- Fulfill BPA's fish and wildlife obligations while assuring a high level of Treasury payment.
- Provide market incentives for the valuation of conservation and renewable resources.

The primary purpose of the Supplemental Proposal is to determine how to deal effectively with the cost recovery risk associated with higher and more uncertain purchase power costs. As noted earlier, this increased uncertainty is being caused by rising prices in a volatile market and high load obligations. However, this phase of the proceeding began, as did the initial phase and the Amended Proposal, with the basic assumption that a solution to the problem should, as much as possible, be designed to preserve the basic principles underlying the Subscription Strategy. The basic framework that has been developed over a period of several years reflects a wide range of public processes, and is predicated on the input of all regional interests and stakeholders. It continues to provide reasonable direction and structure for the rights and corresponding obligations that have been embodied in signed contracts, for service beginning October 1, 2001.

BPA recognizes that the goals of Subscription, primarily the avoidance of rate increases, cannot be fully maintained in light of the dramatic increase in the wholesale electricity market and the deterioration of BPA's financial situation. However, BPA is attempting to minimize the impact of these changes on its customers by seeking to minimize costs for augmenting its power system, and by returning those savings to the customers through the proposed Dividend Distribution Clause (DDC). In addition, the structure of the Load-Based Cost Recovery Adjustment Clause (LB CRAC) allows adjustments to reflect BPA's augmentation costs such that if BPA's augmentation costs drop the LB CRAC will also drop.

1.2.2 Meeting Treasury Payment Probability Goal. BPA is required to set rates to recover its costs. *See* WP-02-FS-BPA-02, at 55-58. Risk mitigation tools were developed in the May Proposal to achieve the TPP goal of 88 percent, and to satisfy Fish and Wildlife Funding Principle No. 4. Principle No. 4 states "[g]iven the range of potential fish and wildlife costs, Bonneville will design rates and contracts which will position Bonneville to achieve similarly high Treasury Payment Probability for the post-2006 period by building financial reserve levels and through other mechanisms." *See* WP-02-FS-BPA-02A, at 344. In the Amended Proposal, the TPP was reduced to 83.4 percent which is still within the range of 80-88 percent. The problem was a cost recovery problem. Therefore, BPA proposed to modify the risk mitigation tools so that revenues were sufficient for a timely recovery of costs. At a minimum, this meant having a TPP within the allowable range called for in the Principles, and meeting Principle No. 4.

In the Amended Proposal the primary means of achieving an acceptable TPP level was a redesign of the CRAC and commensurate changes to the Slice payment for augmentation costs. However, with the continued increases in and volatility of market prices and the deterioration of starting reserve levels, the TPP based on the Amended Proposal dropped below the allowable range. Adjustments to the Amended Proposal were necessary to bring the TPP level within an acceptable range.

1.2.3 Maintaining Regional Benefits. All of BPA's regional customers have signed either a Subscription contract or a Residential Exchange settlement agreement prior to the October 31, 2000, contract-signing deadline.[*] The Subscription contracts translated the Subscription Strategy into product offerings and formalized the proposed distribution of power and benefits developed through the Subscription Strategy. The May Proposal established the price for the products purchased under those contracts. The contracts, as written, have been responsive to the market transformation that has taken place under FERC restructuring and are different from previous contracts. The May Proposal contained rates that are designed to fit the products being offered. As was the case with the Amended Proposal, the Supplemental Proposal preserves the proposed base rates of the May Proposal except for the specific changes noted below.

1.3 Summary of Proposal

1.3.1 Three-Component Cost Recovery Adjustment Clause. In the May ROD, BPA proposed a single CRAC that triggered upon accumulated net revenues (ANR) dropping to pre-identified levels. The Amended Proposal had a three-component CRAC, with each component designed to deal with a different aspect of the problem BPA currently faces. The three components are referred to as the Load–Based CRAC (LB CRAC), Financial-Based CRAC (FB CRAC), and Safety-Net CRAC (SN CRAC). *See* Chapter 5, *infra*. The Supplemental Proposal retained the concept of the three-component CRAC but redesigned the components to better address the changing nature of the cost recovery problem and to conform to the Partial Stipulation and Settlement Agreement reached with the parties.

In the Amended Proposal, the LB CRAC addressed some but not all of the cost recovery problem created by increased augmentation load. Part of the cost recovery obligation for this

[*] BPA offered its IOU customers a Settlement Agreement as an alternative to the benefits under the standard Residential Power Sales Agreement. Customers who did not sign contracts prior to the close of the signing window may still do so but they will be subject to the Targeted Adjustment Charge.

augmentation obligation resided with FB CRAC. Through discussions with the parties, it became apparent that many parties preferred to place all of the costs associated with augmentation purchases on the LB CRAC and not rely on the FB CRAC for part of the solution to this problem. Many parties expressed concern that the contingent nature of the FB CRAC presented rate setting problems for them. Therefore, the LB CRAC was redesigned to fully address the problem of augmentation costs exceeding the May Proposal forecast. Because there is tremendous volatility in the market, and the price forecast is currently high in the near term, trending downward through the period of the rate case, the LB CRAC redesign includes changes to allow it to adjust either up or down to ensure that customers pay the actual cost of augmentation. As in the Amended Proposal, the LB CRAC will be based on aMW amounts in contracts already signed by customers. The load projection derived from these contracts and used for the LB CRAC will provide an indication of how much load BPA will actually be required to serve in the upcoming rate period. However, to the extent that loads are greater than forecast in the May Proposal or in the event there is a load response to the increase in prices, the LB CRAC now will be adjusted every six months to reflect these changes. The price of the augmentation will be covered through a forecast of augmentation costs and every six months will be adjusted based upon actual augmentation purchases and a forward price for the balance of the augmentation need. There would then be an after-the-fact true-up of the forecast based upon any additional augmentation purchases, corresponding changes to the forward prices, and changes in augmentation needs. Therefore, BPA's exposure to market risk due to augmentation purchases required to serve load is effectively mitigated by the LB CRAC.

Because the LB CRAC will account for essentially all of the cost of augmentation, the FB CRAC was modified to address the risks that the single CRAC in the May Proposal was designed to address. The FB CRAC is designed to be similar to the CRAC contained in the May Proposal, with two minor changes. In the event the FB CRAC triggers in the first year of the rate period

(2002), the amounts collected will not be capped, but rather BPA will be allowed to collect the amount that would have restored FY 2002 net revenues to the threshold level. Also, the timing of the FB CRAC has been changed to allow it to affect rates for a 12-month period starting at the beginning rather than the middle of the fiscal year.

The SN CRAC provides BPA with a tool to temporarily adjust the amounts collected under the FB CRAC upward in the event that BPA misses, or forecasts missing, a payment to Treasury or another creditor, even considering implementation of the LB CRAC and the FB CRAC. The SN CRAC would likely not trigger soon enough to avoid an initial deferral, but would help to avoid a second deferral. The Supplemental Proposal calls for a 7(i) process to implement the SN CRAC.

1.3.2 Slice. The Slice of the System product (Slice) was offered as part of BPA's Subscription Strategy. The manner in which augmentation costs were collected under the Slice Methodology in the May Proposal was based on a market price forecast. The Slice Methodology used a fixed market price forecast of $28.10/MWh to price the proportionate Slice share of all augmentation purchases for the rate period. Because of the changes in the wholesale power market, pricing the augmentation purchases at a fixed market price would result in Slice purchasers not paying their proportionate share of the augmentation costs, either higher or lower, depending on the actual cost of augmentation.

In the Amended Proposal, BPA proposed adjustments to the Slice purchaser's bill that would assure that the Slicer's proportionate share of BPA's augmentation costs were covered. In the Supplemental Proposal, the Slice rate is subject to the LB CRAC to ensure that Slice purchasers proportionately share the additional financial risk associated with the increased augmentation requirements, market prices, and market volatility. To avoid burdening Slice purchasers with risks that they have assumed directly through the purchase of the product, the after-the-fact true-up for augmentation costs for Slice purchasers will be different from that for non-Slice customers. With Slice there would only be an after-the-fact true-up for augmentation purchases made 120 days prior to the month in question and no corresponding update for changes in the forward strip price. This difference is due to the hydro risk and obligation to balance its own system that Slice purchasers assume directly. Slice will continue to be exempt from the FB and SN CRACs because Slice purchasers assume a proportionate share of BPA's financial risks and receive a proportionate share of the benefits of the Federal system through the product design.

1.3.3 Investor-Owned Utilities Residential Exchange Program Settlement. The Residential Exchange Program Settlement (REP Settlement) with regional IOUs provides benefits in the form of both power and cash. The monetary portion of the benefits is calculated based on the difference between the Residential Load (RL) or Priority Firm Power (PF) Exchange Subscription rate and BPA's rate case market price forecast. Originally, BPA adopted $28.10/MWh as the five-year flat block price forecast for the monetary benefit component of REP Settlements. After reconsidering the appropriateness of that number, given the escalating and volatile market now being experienced, in the Amended Proposal BPA revised that number to $34.1/MWh. The Supplemental Proposal calculated the financial aspect of the Settlements using $38/MWh for the monetary benefits component of the REP Settlement. In consultation with various Parties, in order to preserve the overall balance between the different aspects of this Supplemental Proposal, raising the financial component of the settlement to $38/MWh was seen as an appropriate adjustment. In addition, the financial component of the Settlement benefits will be exempt from the FB CRAC and LB CRAC but will be subject to the SN CRAC. *See* Chapter 5, *infra.* Both the power deliveries and the financial portion of the Settlement will be used to determine the IOU share of distributions under the DDC.

1.3.4 Early Signers. On August 1, 2000, BPA temporarily suspended the signing of any new power contracts because of the uncertainty created by the projections of increased loads and greater market volatility. Prior to that date, BPA and a number of its customers had already signed new Subscription power contracts for the upcoming rate period that would price power at the PF-02 rate. The timing of the contract signing does not provide a sufficient basis to exempt these contracts from the application of the three-component CRAC in this proposal. However, Pre-Subscription and certain other Firm Power Products and Services sales, including extra-regional surplus sales and approximately 70 aMW of Irrigation Mitigation sales, will not be subject to the CRACs.

1.3.5 Changes to the Dividend Distribution Clause. The Supplemental Proposal redesigned the DDC to make it an automatic redistribution to the customers based upon achieving certain reserve levels. The DDC will not be available in the first year (FY 2002) of the rate period and in the subsequent years will trigger if BPA has the accumulated net revenue equivalent to ending reserve levels of $1.7 billion in FY 2003, $1.5 billion in FY 2004, $1.2 billion in FY 2005, and $1.2 billion in FY 2006. The ending reserve levels will be adjusted to the extent that BPA has unspent but agreed-to funds to mitigate impacts of a Power System Emergency on fish and wildlife, or unspent funds for BPA's current year fish and wildlife direct program. Unlike the May Proposal, this redesign of the DDC will not require any evaluation of the TPP. However, the first $15 million will continue to be allocated to qualifying Conservation and Renewable purposes. And, as mentioned above, the financial portion of the REP Settlement will share in distributions under the DDC.

1.4 Market Price Forecast

In the Amended Proposal, BPA used a risk adjusted market price forecast of $48.37/MWh produced by the AURORA model in its Risk Model Analysis. In the Supplemental Proposal

BPA is proposing to use prices on the forward market, for the first two years of the rate period, rather than relying on AURORA for price forecasts for the entire rate period. AURORA was not able to model the price levels currently in the market. The current market prices are difficult to model in AURORA due to a combination of supply and demand responses that have materialized in the forward markets that are impossible to quantify and model in AURORA. As a consequence, the prices modeled in AURORA during the first two years of the rate period have been replaced with prices reflecting current market reality for that time period. This is more fully explained in Chapter 2, *infra*.

1.5 Organization of Study

This Study updates the final study, documentation, and testimony of the initial Supplemental Proposal. Each chapter cites the specific document that is being updated.

The Appendix to the Final Supplemental ROD contains the revised GRSPs.

CHAPTER 2: RISK ANALYSIS

2.1 Introduction

2.1.1 Background. Since the Risk Analysis Study and Study Documentation for the May Proposal was published (WP-02-FS-BPA-03 and WP-02-FS-BPA-03A), BPA's risk exposure due to uncertainty in the amount and cost of System Augmentation has substantially increased primarily due to higher, more volatile forecasted electricity prices and resulting additional load on BPA. In response to this substantial increase in risk exposure, BPA staff and many of its customers developed a proposal and agreed to a settlement that revises how BPA mitigates its risk exposure. Under the Partial Stipulation and Settlement Agreement, BPA's rates vary depending on the amount and price of actual System Augmentation purchases. Given the substantial uncertainty in the amount and price of actual System Augmentation, this chapter assesses the impact that various load and electricity price scenarios would have on BPA's rates.

2.1.2 Overview. In order to ensure that BPA has a high probability of making its annual Treasury payments on time and in full during the five-year rate period, BPA performs the Risk Analysis Study. In this Study, BPA identifies key risks, models the relationships among the risks, and then analyzes their impacts on net revenues (revenues minus expenses). BPA subsequently evaluates the impact that certain risk mitigation measures have on reducing net revenue risk in order to develop rates that cover all costs and ensure a high probability of making Treasury payments on time and in full during the rate period.

In the Final Risk Analysis Study for the Supplemental Proposal, BPA is analyzing rates over a range of prices and loads so that it achieves between 80 and 88 percent probability that all Treasury payments will be made on time and in full over the five-year rate period. To accomplish this task, it was necessary to quantify and then mitigate key operating and non-operating risks. The first step in this process was the Risk Analysis Study, which identified key risk factors, modeled the relationship among the risk factors, and determined their impacts on net revenues.

The Risk Analysis Study focuses upon two classes of risks and their impacts on BPA's revenues and expenses. The first class of risks is comprised of operating risks. These risks include variations in spot market electricity prices, loads, and generating resource capability (including hydro generation under alternative hydro operations associated with the 13 Fish and Wildlife Alternatives). These operating risks are modeled in the Risk Analysis Model (RiskMod) to quantify their impact on net revenues. The spot market electricity prices used in the net revenue computations in RiskMod are estimated by the Forward Market Price Simulator for fiscal year (FY) 2002–2003 and by the AURORA model for FY 2004–2006. *See* Risk Analysis Study and Study Documentation for the May Proposal (WP-02-FS-BPA-03 and WP-02-FS-BPA-03A) for a detailed description of RiskMod; Marginal Cost Analysis Study and Study Documentation for the May Proposal (WP-02-FS-BPA-04 and WP-02-FS-BPA-04A) for a detailed description of AURORA; and Chapter 2 of the initial Supplemental Proposal Study (WP-02-E-BPA-67) for a detailed description of the Forward Market Price Simulator.

The second class of risks are non-operating risks. These risks include uncertainties in capital costs and expenses (but not operational impacts) associated with the 13 Fish and Wildlife Alternatives identified in the Fish and Wildlife Funding Principles (Principles). This class of non-operating risks also includes uncertainty in achieving cost reductions identified in the Cost Review recommendations, costs associated with business line separation, costs associated with conservation and renewables, and interest rates. These risk are modeled in the Non-Operating Risk Model (NORM). *See* Risk Analysis Study and Study Documentation for the May Proposal, WP-02-FS-BPA-03 and WP-02-FS-BPA-03A.

The output from RiskMod and NORM are combined to develop a distribution of net revenue deviations that are input into the ToolKit Model. The ToolKit Model uses the net revenue data to test the effectiveness of implementing various risk mitigation measures in order to meet BPA's Treasury Payment Probability (TPP) standard.

The ToolKit Model assesses the impact of the net revenue deviations on cash reserve levels, calculates the probability that BPA will make its Treasury payments on time and in full, and determines the combination of risk mitigation tools (*e.g.,* Cost Recovery Adjustment Clause (CRAC) trigger levels and amounts) that are needed to meet BPA's 80 to 88 percent TPP goal.

2.2 Changes in the Risk Analysis Study

2.2.1 Overview of Changes in the Risk Analysis Study. The Risk Analysis Study for the Final Supplemental Proposal incorporates several changes from the Risk Analysis Study performed for the initial Supplemental Proposal. The changes include the following: (1) changes in RiskMod; (2) revised loads and resources; and (3) revised monthly forward market electricity prices and price variability for FY 2002 and 2003.

2.2.2 Changes in Risk Analysis Model. Changes in RiskMod for the Final Supplemental Proposal were the following: (1) the expected amount of energy that BPA will have stored in Non-Treaty Storage at the start of FY 2002 was updated; (2) Non-Treaty Storage operations for FY 2002 were modified; and (3) the expected Fish Cost Contingency Fund (FCCF) reserve at the start of FY 2002 was updated.

For the Final Supplemental Proposal, the expected amount of energy that BPA will have stored in Non-Treaty Storage at the start of FY 2002 was updated to 500 MW/months. This storage level is a reduction from the 1,000 MW/months used in the Supplemental Proposal (*see*

Chapter 2 of the initial Supplemental Proposal Study, WP-02-E-BPA-67) and reflects the impact of continued dry weather conditions during FY 2001.

Non-Treaty Storage operations in RiskMod for FY 2002 were modified from typical Non-Treaty Storage operations to better reflect the impact that projected poor streamflow conditions, projected low FY 2001 starting reservoir levels for the Federal Columbia River Power System (FCRPS), and high market prices in FY 2002 would have on such operations. Under such conditions, it is unlikely that BPA will be either storing in or withdrawing from Non-Treaty Storage during October 2001–December 2001. BPA will likely preserve the 500 MW/months it has stored in Non-Treaty Storage for System Reliability needs during the winter and any excess energy in the fall will probably be either sold on the wholesale electricity market or stored in the FCRPS.

Revisions in the expected Non-Treaty Storage operations during October 2001–December 2001 were accounted for in RiskMod by setting the storage and withdrawal constraints for these three months to zeros, which prevents any storage in or withdrawal from Non-Treaty Storage. Table 2-1 reports the typical Non-Treaty Storage release and storage limits used for FY 2003-2006 and the release and storage constraints used for FY 2002.

Table 2-1: Non-Treaty Storage Monthly Constraints (FY 2002-06)

Final Supplemental Proposal (FY 2002)

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Monthly Maximum Storage (MW-Mo)	0	0	0	1350	1350	675	270	675	675	0	0	675
Monthly Maximum Release (MW-Mo)	0	0	0	675	675	675	0	0	0	675	675	675

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	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
Monthly Maximum Storage (MW-Mo)	675	675	1350	1350	1350	675	270	675	675	0	0	675
Monthly Maximum Release (MW-Mo)	675	675	270	675	675	675	0	0	0	675	675	675

For the Final Supplemental Proposal, BPA revised the expected Fish Cost Contingency Fund (FCCF) reserve at the start of FY 2002 to a point forecast of $154.7 million, reflecting updated information on the likelihood and amount that BPA will be accessing the FCCF reserve in FY 2001. In the Chapter 2 of the initial Supplemental Proposal Study (WP-02-E-BPA-67), BPA used a point forecast of $167 million as the expected FCCF reserve at the start of FY 2002. The FCCF reserve at the start of FY 2001 was $325 million.

2.2.3 Revisions in Loads and Resources. For the Final Study for the Supplemental Proposal, BPA updated its Priority Firm Power (PF) sales forecast from the sales forecast that was used in the Risk Analysis Study for the initial Supplemental Proposal Study. No changes were made to the Industrial Firm Power (IP) and Residential Load Firm Power (RL) sales forecast from the IP and RL sales forecasts used in the initial Supplemental Proposal Study. All the load buy-downs and voluntary load reductions included in the Risk Analysis Study were accounted for as System Augmentation purchases, not as reductions in load.

For the Final Supplemental Proposal, average forecasted PF sales to public agencies over the 5-year rate period for the Risk Analysis Study increased by 12 aMW (from 5,815 aMW, including 2,000 aMW of Slice, to 5,827, including 1,600 aMW of Slice) from the initial Supplemental Proposal Study. The change was due to the following: (1) the additional load growth resulting from a few customers that switched from Slice to a load following product; (2) a customer with a contingent contract becoming a partial requirements customer; (3) minor forecast adjustments for individual utilities; and (4) correcting a calculation error in the load growth algorithm for the contingent contracts.

Table 2-2 lists the public utilities purchasing the Full Service, Partial Service, and Block products for the Risk Analysis Study. Table 2-3 displays the projected product energy and peaking sales diurnally by month for FY 2002– 2006 for the Risk Analysis Study. With the exception of revisions to the PF sales forecast and the previously reported increase in the monthly Direct Service Industrial Customers (DSI) load by a flat 46 aMW allocated to Alcoa (*See* Section 2.2.3, Amended Proposal Study, WP-02-E-BPA-58), all other firm load obligations used in the Risk Analysis Study for the Final Supplemental Proposal are the same as in the Load and Resource Study and Study Documentation for the May Proposal (WP-02-FS-BPA-01, WP-02-FS-BPA-01A).

Table 2-2
Product Choices by Customer
With Slice Sales Forecast

Full Service

Alder	Ellensburg	Nespelem
Ashland	Emerald	Northern Wasco
Bandon	EnergyNW	Oregon Trail
Bangor	Fairchild	Pacific Co
Benton REA	Ferry	Peninsula
BIA-Wapato	Fircrest	Plummer
Big Bend	Forest Grove	Port Angeles
Blaine	Harney	Richland
Bonners Ferry	Heyburn	Rupert
Bremerton	Hood River	Salem
Bureau of Mines	Idaho County	Skamania
Burley	Jim Creek	Steilacoom
Canby	Kittitas	Sumas
Cascade Locks	Lakeview	Surprise V.
Centralia	Lewis Co. PUD	Tanner
Cheney	Mason #1	Tillamook
Clallam	Mason #3	United
Columbia River	McCleary	Vera
Consolidated Irr Dist	Midstate	Wahkiakum
DOE-Midway/Richland	Milton	Wells
Drain	Milton-Freewater	Whatcom
Eatonville	Monmouth	

Partial Service

Central Lincoln	Flathead	McMinnville
Cowlitz	Klickitat	Springfield

Block

Clark	Grant	Tacoma
Benton PUD	Fall River	Pend Oreille
Blachly-Lane	Franklin	Raft River
Central Electric	Grays Harbor	Salmon River
Clatskanie	IdahoFalls	Seattle
Clearwater	Lane Electric	Snohomish
Consumers Power	Lost River	Umatilla
Coos-Curry	Northern Lights	West OR
Douglas Electric	Okanogan Coop	
EWEB	Okanogan PUD	

Table 2-3
Projected Full, Partial, and Block Sales
Reflects 1600 aMW of Slice Sales
FY 2002-2006

	Full & Partial Service			**Block**			**Load Variance**
	HLH MWh	LLH MWh	Peak MW	HLH MWh	LLH MWh	Peak MW	MWh
Oct-01	962014	635998	2810	671872	477518	1555	1804881
Nov-01	1059266	682383	3051	796242	566480	1914	1982017
Dec-01	1223141	780353	3333	934149	699306	2246	2258371
Jan-02	1257022	814492	3641	971358	683821	2249	2316049
Feb-02	1091139	711396	3218	849049	614825	2211	2022263
Mar-02	1063189	696172	3118	844932	634297	2031	1984761
Apr-02	1007856	643398	2803	775236	548328	1864	1848447
May-02	934486	609877	2414	774591	545406	1793	1720869
Jun-02	895326	567368	2216	605093	461034	1513	1623563
Jul-02	937047	568232	2307	665614	463557	1541	1668924
Aug-02	947235	595092	2393	682357	479180	1580	1704715
Sep-02	951411	569996	2493	643728	488557	1609	1690912
Oct-02	1012993	633041	2892	674896	474494	1562	1843233
Nov-02	1089605	702677	3138	799570	563152	1922	2023858
Dec-02	1250420	795980	3405	937893	695562	2255	2308303
Jan-03	1285030	832349	3730	973518	681661	2254	2375207
Feb-03	1110342	723513	3283	850969	612905	2216	2064234
Mar-03	1081094	707359	3179	847012	632217	2036	2025124
Apr-03	1028554	654453	2865	776900	546664	1868	1886364
May-03	954918	620837	2470	775887	544110	1796	1758630
Jun-03	917819	580450	2279	606693	459434	1517	1657117
Jul-03	961937	582040	2371	666910	462261	1544	1707124
Aug-03	973586	607233	2455	677157	484380	1628	1741806
Sep-03	973525	584642	2556	651120	481165	1565	1725998
Oct-03	1040733	648828	2968	676624	472766	1566	1880620
Nov-03	1122001	718727	3222	794834	567888	1987	2063999
Dec-03	1279144	816522	3492	947109	686346	2192	2353643
Jan-04	1318243	851853	3831	976974	678205	2262	2420813
Feb-04	1152367	747112	3405	861337	608729	2243	2123927
Mar-04	1107604	726540	3275	856180	623049	1982	2065511
Apr-04	1051789	669547	2944	779812	543752	1875	1923485
May-04	978705	633608	2535	772895	547102	1858	1794126
Jun-04	938244	596561	2340	615237	450890	1479	1695971
Jul-04	984564	596419	2434	669502	459669	1550	1744693
Aug-04	996516	622326	2518	679653	481884	1634	1779737
Sep-04	995527	598595	2617	653616	478669	1571	1761780
Oct-04	1063069	660338	3039	674096	475294	1620	1918420
Nov-04	1141177	734349	3295	804146	558576	1933	2104734
Dec-04	1304498	832538	3559	950565	682890	2200	2400024
Jan-05	1346682	866513	3909	974078	681101	2342	2466703
Feb-05	1162566	756042	3452	858265	605609	2235	2142920
Mar-05	1128817	740274	3341	860500	618729	1992	2104585
Apr-05	1072315	682613	3005	783556	540008	1884	1960900
May-05	998490	646409	2589	776639	543358	1867	1830578
Jun-05	957837	609360	2396	618565	447562	1487	1732617
Jul-05	1008820	609704	2492	666318	462853	1602	1786098
Aug-05	1017587	638154	2577	689701	471836	1597	1821515
Sep-05	1017105	612227	2675	656944	475341	1579	1801386
Oct-05	1082961	673049	3099	677840	471550	1629	1959384
Nov-05	1163143	748572	3360	808306	554416	1943	2149244
Dec-05	1329534	848333	3629	955317	678138	2211	2449710
Jan-06	1375729	885706	3993	979070	676109	2354	2516747
Feb-06	1187586	772645	3527	862489	601385	2246	2186065
Mar-06	1154211	757136	3414	864820	614409	2002	2148409
Apr-06	1098756	697127	3072	781300	542264	1953	2002136
May-06	1019621	662827	2650	785823	534174	1819	1870296
Jun-06	977800	622358	2448	621893	444234	1495	1767362
Jul-06	1030509	623494	2548	669646	459525	1610	1823369
Aug-06	1039572	652345	2635	693157	468380	1605	1864002
Sep-06	1037847	625308	2731	660688	471597	1588	1836985

Because of the uncertainty in the load that will be placed on BPA, BPA chose in the Final Supplemental Proposal to perform risk analyses using two levels of load (which impacts the amount of System Augmentation) and three levels of System Augmentation purchase prices. The load scenarios analyzed were the loads used in the Final Supplemental Proposal and a load reduction of 750 average megawatt (aMW) from the loads used in the Final Supplemental Proposal.

Resources used in the Final Supplemental Proposal are identical to those used in the Risk Analysis Study for the initial Supplemental Proposal Study, except for actual System Augmentation purchases. Actual System Augmentation purchases used in RiskMod for the initial Supplemental Proposal Study amounted to 1,048 aMW/year at a cost of $280.5 million/year ($30.55/MWh) and were based on all purchases as of January 1, 2001. *See* Tables 2-1 and 2-2 in the initial Supplemental Proposal Study, WP-02-E-BPA-67. Actual System Augmentation purchases used in RiskMod for the Final Supplemental Proposal amount to 1,842 aMW/year at a cost of $550.2 million/year ($34.1/MWh) and were based on all purchases as of June 1, 2001. *See* Tables 2-4 and 2-5 in this Study.

Table 2-4: System Augmentation Purchases as of June 1, 2001

	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Avg.
Flat Purchases (aMW)	2,470	2,470	2,470	2,695	2,695	2,695	2,042	1,642	1,642	2,407	2,407	2,407	**2,336**
HLH Energy Purchases (aMW)	2,480	2,480	2,480	2,695	2,695	2,695	2,042	1,642	1,642	2,407	2,407	2,407	**2,339**
LLH Energy Purchases (aMW)	2,455	2,455	2,455	2,695	2,695	2,695	2,042	1,642	1,642	2,407	2,407	2,407	**2,333**

	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Avg.
Flat Purchases (aMW)	2,370	2,370	2,370	2,356	2,356	2,356	1,806	1,406	1,406	2,356	2,356	2,356	**2,155**
HLH Energy Purchases (aMW)	2,392	2,392	2,392	2,367	2,367	2,367	1,817	1,417	1,417	2,367	2,367	2,367	**2,169**
LLH Energy Purchases (aMW)	2,342	2,342	2,342	2,342	2,342	2,342	1,792	1,392	1,392	2,342	2,342	2,342	**2,138**

	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Avg.
Flat Purchases (aMW)	1,836	1,836	1,836	1,747	1,747	1,747	1,197	797	797	1,747	1,747	1,747	**1,565**
HLH Energy Purchases (aMW)	1,847	1,847	1,847	1,747	1,747	1,747	1,197	797	797	1,747	1,747	1,747	**1,568**
LLH Energy Purchases (aMW)	1,822	1,822	1,822	1,747	1,747	1,747	1,197	797	797	1,747	1,747	1,747	**1,562**

	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Avg.
Flat Purchases (aMW)	1,747	1,885	1,893	1,878	1,881	1,833	1,287	887	912	1,924	1,920	1,918	**1,664**
HLH Energy Purchases (aMW)	1,747	1,988	1,997	1,976	1,982	1,898	1,354	954	997	1,997	1,997	1,997	**1,740**
LLH Energy Purchases (aMW)	1,747	1,747	1,754	1,747	1,747	1,747	1,197	797	797	1,827	1,818	1,813	**1,562**

	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Avg.
Flat Purchases (aMW)	1,974	1,936	1,962	1,498	1,498	1,420	1,080	870	968	1,582	1,556	1,553	**1,491**
HLH Energy Purchases (aMW)	2,066	2,039	2,067	1,596	1,599	1,485	1,150	934	1,054	1,655	1,633	1,660	**1,578**
LLH Energy Purchases (aMW)	1,722	1,688	1,695	1,288	1,288	1,383	938	738	738	1,368	1,360	1,379	**1,299**

5-Year Average

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Avg.
Flat Purchases (aMW)	2,079	2,099	2,106	2,035	2,035	2,010	1,482	1,120	1,145	2,003	1,997	1,996	**1,842**
HLH Energy Purchases (aMW)	2,107	2,149	2,157	2,076	2,078	2,038	1,512	1,149	1,181	2,035	2,030	2,036	**1,879**
LLH Energy Purchases (aMW)	2,018	2,011	2,014	1,964	1,964	1,983	1,433	1,073	1,073	1,938	1,935	1,937	**1,779**

Note: Load reductions have been inflated by 2.82% to account for avoided transmission losses.

Table 2-5: System Augmentation Expenses as of June 1, 2001

	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	Average
System Augmentation Expenses ($Million)	669.2	594.0	494.0	521.5	472.1	550.2

Given that the Rate Case parties bear the risk of the amount and price of System Augmentation under the Partial Stipulation and Settlement Agreement (rather than BPA), the terms of this agreement were modeled in RiskMod by computing the cost of all unpurchased System Augmentation using updated fixed, average flat energy prices. The shape of the unpurchased System Augmentation was defined by the "Shaped Augmentation by Year" provided in Table C of Appendix 2 in Chapter 5 of the Final Supplemental Proposal Study Documentation (WP-02-FS-BPA-10). These modifications removed the risk of the amount and price of System Augmentation purchases from the net revenue risk estimated by RiskMod.

2.2.4 Changes in the Risk Simulation Models. For the Final Supplemental Proposal, the monthly forward market electricity prices and electricity price volatilities were updated in the Forward Market Price Simulator. This risk model simulates market price uncertainty for FY 2002 and 2003 using inputted monthly forward market electricity prices and implied electricity price volatilities derived from option premiums. These simulated electricity prices formed the basis for calibrating the FY 2002 and 2003 electricity prices estimated by AURORA in the Amended Proposal to current market conditions using a methodology described in the initial Supplemental Proposal. *See* Sections 2.2.4 and 2.2.7 of the Supplemental Proposal Study, WP-02-E-BPA-67.

The monthly flat forward market electricity prices for FY 2002 and 2003 were collected and the implied electricity price volatilities were derived from over-the-counter quotes from dealers/brokers for the Mid-Columbia delivery point. These monthly quotes were assembled on May 23, 2001 and reflect prices and option premiums at which dealers/brokers would be willing to make transactions in either 25 or 50 aMW increments at the time the data was collected.

The monthly flat forward market electricity prices and the implied price volatilities used in the Forward Market Price Simulator for FY 2002 and 2003 are shown in Table 2-6 and Table 2-7. The annual average flat energy prices quoted by dealers/brokers averaged $148.00/MWh in FY 2002 and $63.00/MWh in 2003. Statistical information for the simulated monthly flat forward market electricity prices for FY 2002 and 2003 are reported in Table 2-8 and Table 2-9.

Table 2-6: Inputs to the Forward Market Price Simulator for FY 2002

Date **5/23/01**

Price Inputs	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02
Expected Spot Prices ($/MWh)	$217.74	$171.11	$224.57	$211.25	$163.57	$103.98
Implied Spot Volatility (Monthly)	25.11%	24.10%	23.09%	22.12%	21.46%	20.74%
Implied Volatility (Annualized)	87.00%	83.50%	80.00%	76.63%	74.35%	71.85%
	Apr-02	**May-02**	**Jun-02**	**Jul-02**	**Aug-02**	**Sep-02**
Expected Spot Prices ($/MWh)	$69.19	$71.99	$86.50	$154.78	$181.07	$114.34
Implied Spot Volatility (Monthly)	19.87%	19.72%	20.74%	23.31%	22.30%	21.29%
Implied Volatility (Annualized)	68.83%	68.33%	71.85%	80.75%	77.25%	73.75%

Table 2-7: Inputs to the Forward Market Price Simulator for FY 2003

Date **5/23/01**

Price Inputs	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03
Expected Spot Prices ($/MWh)	$80.54	$63.25	$82.98	$76.45	$56.01	$45.77
Implied Spot Volatility (Monthly)	15.00%	14.36%	14.00%	13.01%	12.63%	12.96%
Implied Volatility (Annualized)	51.98%	49.75%	48.50%	45.07%	43.74%	44.91%
	Apr-03	**May-03**	**Jun-03**	**Jul-03**	**Aug-03**	**Sep-03**
Expected Spot Prices ($/MWh)	$32.86	$33.97	$46.73	$81.81	$94.44	$61.28
Implied Spot Volatility (Monthly)	12.15%	12.22%	12.59%	15.16%	14.64%	14.62%
Implied Volatility (Annualized)	42.08%	42.32%	43.61%	52.50%	50.71%	50.65%

Table 2-8: Statistics for Simulated Monthly FY 2002 Forward Market Prices

Statistics	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Average
Average	217.57	170.72	226.13	210.73	163.78	105.08	69.58	71.71	85.79	155.55	183.32	114.32	**147.86**
Minimum	23.29	24.81	29.93	27.32	17.44	12.13	8.00	6.88	5.57	8.28	10.44	7.41	
Maximum	1,131.82	808.01	1,777.51	1,158.36	1,015.32	947.05	568.22	411.52	518.93	1,911.76	2,479.28	1,135.42	
Standard Deviation	142.10	114.80	172.24	150.64	123.05	87.55	55.93	55.45	72.53	177.18	215.50	120.30	

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
5%	67.94	50.21	62.53	57.74	43.66	26.71	17.86	17.40	18.27	23.39	28.68	18.54
10%	83.60	62.97	79.92	73.63	55.79	34.62	23.03	22.79	24.16	32.72	39.37	25.61
15%	97.31	73.65	94.11	86.31	65.67	40.84	27.09	26.95	29.05	40.87	48.93	31.82
20%	109.56	83.24	106.64	98.08	74.20	46.53	31.05	30.95	33.77	48.64	58.10	37.67
25%	121.05	92.52	118.69	109.20	83.33	52.29	34.67	34.84	38.27	56.39	67.02	43.54
30%	132.46	101.12	130.47	120.84	92.39	57.81	38.40	38.75	42.90	64.67	77.02	49.64
35%	144.20	110.52	142.87	132.21	100.89	63.47	42.21	42.92	47.86	73.10	86.56	55.76
40%	156.03	120.26	154.84	143.92	110.25	69.28	46.21	47.05	52.85	82.57	97.73	62.42
45%	168.39	129.89	168.01	156.85	120.03	75.79	50.46	51.44	58.46	92.74	109.44	69.79
50%	181.69	140.68	182.30	170.12	130.97	82.40	54.77	56.14	64.12	103.78	121.86	78.29
55%	196.14	152.40	198.17	185.01	142.44	89.82	59.83	61.13	70.97	116.24	136.13	87.02
60%	210.81	164.72	215.00	200.59	154.92	97.75	65.23	66.82	77.82	130.16	153.01	97.21
65%	229.13	178.88	232.99	218.42	168.79	107.04	71.20	73.35	86.28	145.45	171.79	108.76
70%	248.93	194.84	254.50	239.31	184.63	117.21	78.33	81.10	96.36	165.11	194.69	122.74
75%	271.90	213.14	281.05	263.36	204.23	129.99	86.50	89.87	107.88	188.18	220.84	140.74
80%	300.80	236.81	312.30	295.58	228.96	145.47	97.00	101.04	122.41	219.59	256.49	162.79
85%	337.32	267.17	353.91	333.33	259.73	165.27	110.60	115.89	141.41	261.08	304.15	191.54
90%	388.33	312.18	411.77	391.79	307.54	196.59	129.77	137.10	170.27	326.03	378.62	237.38
95%	480.82	385.72	522.07	492.86	385.35	250.53	167.64	176.13	223.27	439.14	513.48	320.22

Table 2-9: Statistics for Simulated Monthly FY 2003 Forward Market Prices ($/MWh)

Statistics	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Average
Average	80.47	63.10	83.51	76.30	56.07	46.15	32.99	33.88	46.49	82.08	95.24	61.27	**63.13**
Minimum	7.57	9.24	11.82	12.17	7.97	6.58	5.14	4.60	4.97	6.56	8.19	5.39	
Maximum	452.67	297.30	620.91	364.33	286.62	349.19	211.22	157.79	216.22	773.79	966.66	501.05	
Standard Deviation	55.90	42.27	61.06	48.68	36.19	33.83	22.17	22.10	31.71	77.43	91.10	56.05	

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
5%	23.37	18.65	24.15	24.00	17.89	13.51	10.36	10.25	13.35	16.29	19.78	12.31
10%	29.08	23.37	30.64	29.92	22.21	17.11	12.93	12.94	16.85	21.87	26.06	16.47
15%	34.13	27.32	35.91	34.56	25.65	19.89	14.89	14.95	19.64	26.57	31.51	20.03
20%	38.67	30.86	40.53	38.81	28.56	22.40	16.77	16.85	22.26	30.95	36.60	23.32
25%	42.95	34.29	44.97	42.78	31.64	24.92	18.47	18.67	24.70	35.24	41.46	26.57
30%	47.23	37.47	49.29	46.90	34.65	27.31	20.18	20.47	27.16	39.74	46.80	29.90
35%	51.65	40.94	53.83	50.88	37.44	29.74	21.92	22.36	29.75	44.25	51.82	33.19
40%	56.12	44.53	58.20	54.96	40.49	32.20	23.72	24.21	32.31	49.23	57.61	36.75
45%	60.82	48.09	63.00	59.42	43.64	34.95	25.61	26.15	35.14	54.51	63.58	40.63
50%	65.89	52.07	68.19	63.96	47.13	37.72	27.50	28.20	37.95	60.16	69.83	45.06
55%	71.42	56.39	73.94	69.01	50.75	40.80	29.70	30.35	41.29	66.44	76.91	49.56
60%	77.06	60.93	80.02	74.27	54.64	44.07	32.03	32.78	44.58	73.37	85.17	54.76
65%	84.13	66.15	86.51	80.23	58.94	47.88	34.57	35.53	48.58	80.88	94.22	60.59
70%	91.81	72.04	94.24	87.16	63.79	52.01	37.56	38.75	53.26	90.39	105.08	67.56
75%	100.75	78.77	103.76	95.07	69.72	57.15	40.96	42.35	58.51	101.37	117.29	76.42
80%	112.07	87.49	114.94	105.56	77.11	63.32	45.26	46.87	65.00	116.06	133.65	87.13
85%	126.45	98.67	129.76	117.72	86.17	71.13	50.74	52.76	73.29	135.07	155.06	100.87
90%	146.67	115.23	150.30	136.30	100.02	83.32	58.32	61.02	85.54	164.12	187.70	122.37
95%	183.69	142.28	189.20	167.84	122.02	103.92	72.90	75.77	107.17	213.08	244.84	160.24

2.2.5 Changes in the Non-Operating Risk Model. No changes were made to NORM for the Final Supplemental Proposal.

2.2.6 Changes in the Natural Gas Price Forecast. No changes were made to the natural gas price forecast for the Final Supplemental Proposal. While the short-term natural gas price forecast (based on NYMEX futures prices) has changed, BPA used the Forward Market Price Simulator to simulate electricity market prices in FY 2002 and 2003. Since the Forward Market Price Simulator does not use natural gas prices when simulating electricity prices, updating the short-term natural gas price forecast is irrelevant. Also, BPA did not update its mid-term natural gas price forecast, since it believes that the mid-term natural gas price forecast for FY 2004-2006 is still valid.

2.2.7 Changes in AURORA. For the Final Supplemental Proposal, BPA did not update the electricity prices from AURORA. BPA used the same monthly HLH and LLH electricity prices estimated by AURORA for FY 2004-2006 as it used in the Amended and initial Supplemental Proposals. For FY 2002 and 2003 in the Final Supplemental Proposal, BPA updated monthly forward market flat energy prices and implied price volatilities in the Forward Market Price Simulator and simulated monthly electricity prices. *See* Section 2.2.4 of the initial Supplemental Proposal Study, WP-02-E-BPA-67, for a description of the methodology used in the Forward Market Price Simulator. These simulated electricity prices formed the basis for calibrating the FY 2002 and 2003 electricity prices estimated by AURORA in the Amended Proposal to current market price conditions. *See* Section 2.2.7 of the initial Supplemental Proposal Study, WP-02-E-BPA-67, for a description of the methodology used to calibrate FY 2002 and 2003 prices estimated by AURORA to prices simulated by the Forward Market Price Simulator.

Tables 2-10 and 2-11 contain the statistical information for the FY 2002 and 2003 calibrated electricity prices. These results can be compared to the statistical information on the FY 2002 and 2003 electricity prices simulated by the Forward Market Price Simulator contained in Tables 2-8 and 2-9 of this study. For illustrative purposes, results from the calibration process for October 2001 are provided in Table 2-12.

Table 2-10: Statistics for Calibrated Monthly FY 2002 Forward Market Prices ($/MWh)

Statistics	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Average
Average	217.55	170.59	225.82	210.93	163.67	105.28	69.76	71.61	85.89	155.43	183.46	114.38	**147.86**
Minimum	54.01	30.87	32.65	68.08	23.31	5.17	2.88	0.82	4.25	3.10	1.53	2.18	
Maximum	1,162.61	935.93	1,148.14	836.32	734.07	498.34	366.83	469.79	823.04	907.20	1,272.73	1,266.68	
Median	174.96	138.34	184.57	153.62	120.40	86.66	61.38	59.96	68.34	100.17	116.90	76.09	
Standard Deviation	141.54	119.28	158.05	140.01	116.30	75.24	49.70	59.27	80.39	159.64	190.78	127.35	

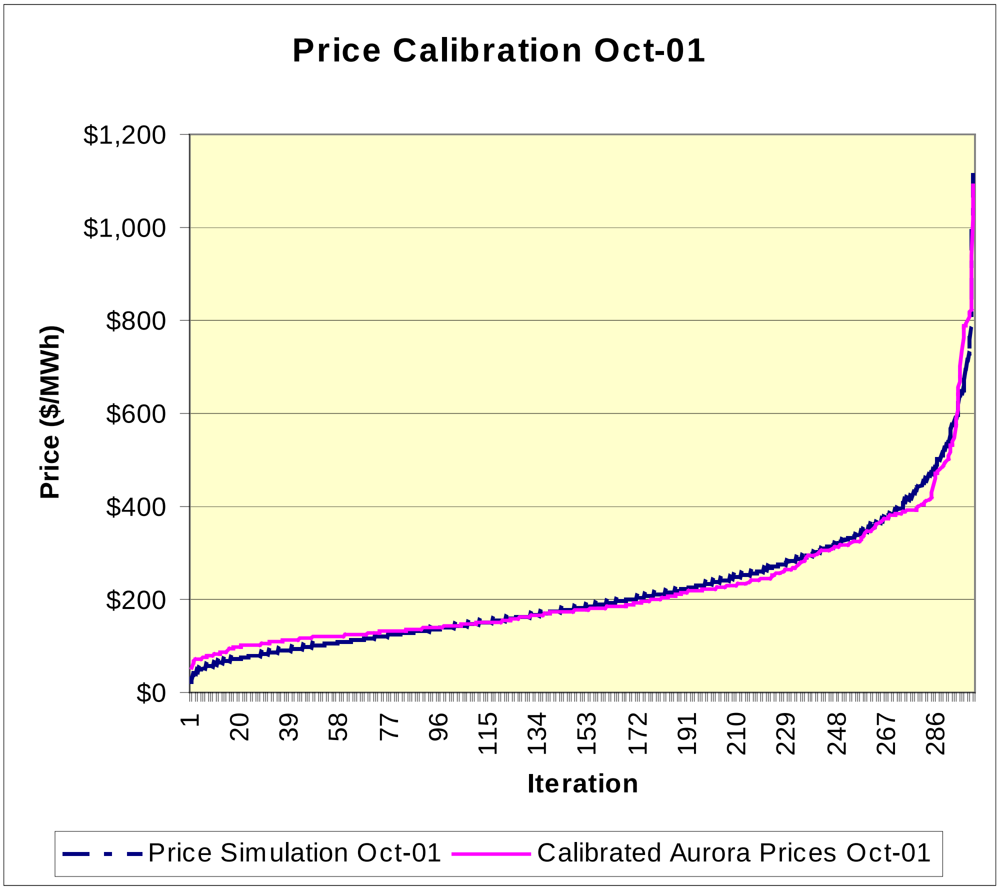
	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
5%	92.55	51.65	58.18	101.60	61.81	36.36	23.99	7.36	14.14	9.56	15.02	16.90
10%	106.79	63.22	75.97	108.63	71.77	43.52	26.89	11.09	21.80	16.58	25.74	21.09
15%	118.29	71.20	86.96	114.68	79.92	49.58	29.28	14.51	27.46	25.29	35.86	26.12
20%	122.89	82.59	100.05	120.94	85.62	53.66	32.06	20.15	31.00	31.65	44.94	31.36
25%	130.37	90.00	111.43	127.19	92.55	59.19	36.01	26.59	36.40	38.92	54.95	36.55
30%	137.19	98.19	125.83	131.73	96.82	63.09	40.48	33.32	41.57	49.15	64.56	42.89
35%	145.67	103.52	138.75	136.25	103.88	68.46	44.59	42.37	48.84	67.31	73.34	50.98
40%	152.72	114.87	154.62	142.24	109.29	75.55	47.90	47.14	55.99	73.27	86.28	57.09
45%	166.65	127.48	169.89	148.00	114.38	80.69	56.56	53.94	61.73	85.75	97.62	63.83
50%	174.96	138.34	184.57	153.62	120.40	86.66	61.38	59.96	68.34	100.17	116.90	76.09
55%	182.90	151.89	200.77	159.92	128.63	92.85	66.30	67.61	76.23	119.07	133.82	87.16
60%	198.15	160.09	221.34	165.66	141.81	99.40	69.41	78.08	81.71	142.67	157.50	98.96
65%	216.50	178.12	237.91	174.96	154.82	104.18	73.01	84.66	89.12	169.74	183.40	113.59
70%	229.29	198.47	271.67	187.55	168.78	113.74	78.61	91.36	96.78	205.40	219.52	123.20
75%	254.69	217.02	291.55	212.35	184.83	120.60	81.02	99.94	105.74	219.24	267.61	144.42
80%	295.58	239.52	333.98	284.13	227.10	135.51	94.22	107.80	125.04	252.48	296.77	173.39
85%	321.07	263.80	376.64	367.79	270.51	153.48	104.86	118.06	140.74	285.25	336.54	205.18
90%	383.44	328.12	420.31	435.99	330.25	178.30	122.96	137.75	159.53	332.16	426.82	242.86
95%	474.72	394.73	531.13	512.87	400.04	264.86	164.47	178.62	208.48	503.72	562.79	327.46

Table 2-11: Statistics for Calibrated Monthly FY 2003 Forward Market Prices ($/MWh)

Statistics	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Average
Average	80.32	62.86	83.49	76.23	56.07	46.03	32.97	33.90	46.63	82.32	95.21	61.61	**63.14**
Minimum	23.38	17.29	21.52	22.48	11.41	2.62	2.35	1.64	5.83	1.53	4.46	4.08	
Maximum	526.17	372.12	376.07	296.35	396.62	292.00	163.75	203.36	190.01	400.07	452.56	288.84	
Median	66.35	49.77	66.04	62.49	48.59	38.27	28.78	30.52	39.79	66.97	70.37	43.43	
Standard Deviation	55.51	43.82	55.71	44.53	36.78	31.12	21.98	24.01	31.47	72.72	81.17	53.87	

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
5%	36.04	24.06	30.12	36.58	24.47	15.83	6.11	5.89	11.75	8.21	13.38	9.86
10%	41.23	26.55	34.65	43.82	28.48	22.04	9.54	8.07	15.78	11.86	18.73	15.11
15%	44.13	29.19	38.28	47.25	30.82	24.31	11.56	9.07	18.53	16.36	24.25	18.71
20%	47.43	32.57	43.04	50.75	34.58	27.22	14.95	11.43	22.82	21.37	29.50	21.22
25%	51.14	34.99	44.75	52.80	37.88	29.67	17.89	14.36	25.20	25.18	35.83	24.04
30%	54.99	37.90	46.99	55.08	40.00	31.01	19.65	17.39	28.59	29.77	43.14	27.54
35%	58.79	42.21	50.79	57.75	41.66	32.42	21.88	19.41	30.35	38.78	47.30	30.71
40%	61.80	44.11	53.68	58.90	43.82	34.59	24.00	24.29	35.35	47.02	57.39	36.59
45%	64.78	47.39	60.87	60.48	46.05	36.70	26.30	26.26	36.66	53.71	63.87	39.79
50%	66.35	49.77	66.04	62.49	48.59	38.27	28.78	30.52	39.79	66.97	70.37	43.43
55%	69.67	52.87	73.21	64.65	50.54	41.89	30.39	33.77	43.12	73.44	78.84	47.67
60%	73.41	57.18	77.92	66.54	53.93	43.13	33.59	37.30	46.21	81.79	89.94	54.30
65%	79.19	61.97	86.13	69.37	57.06	45.39	37.28	40.43	49.74	89.18	100.19	62.52
70%	84.82	69.63	95.17	73.58	60.44	48.98	41.43	44.72	52.73	100.99	114.52	70.34
75%	88.70	75.57	105.58	77.22	63.81	53.65	44.72	48.17	55.86	115.19	131.00	84.09
80%	96.33	82.98	120.50	87.67	69.07	57.80	48.94	52.03	63.34	128.61	145.60	94.15
85%	104.05	94.33	131.84	105.01	75.35	62.63	53.25	57.48	74.39	149.57	166.63	111.29
90%	125.13	111.56	150.07	131.50	85.98	76.85	60.45	63.41	86.30	181.66	203.24	133.62
95%	157.64	142.23	198.38	171.86	104.98	103.16	71.97	73.82	101.92	225.85	277.68	171.24

Table 2:12 Example of the Price Calibration Process



Price Factor	**4.28**
Power Factor	**0.91**
Sim Avg Price	**217.57**
Sim Price Stdev	**142.10**
Fitted Avg Price	**217.57**
Fitted Price Stdev	**136.16**

Due to uncertainty in electricity prices, risk analyses were performed using alternative sets of prices in FY 2002 and 2003. These alternative prices were selected for illustrative purposes and were used to verify that BPA met its financial goal of an 80-88 percent TPP under various price scenarios. To the extent that BPA over-collects revenues, the DDC will redistribute funds to customers.

The alternative sets of forward market electricity prices were developed by scaling each of the monthly FY 2002 and 2003 calibrated prices either upward or downward. The FY 2002 annual flat energy prices analyzed were $100/MWh, $148/MWh, and $225/MWh. The FY 2003 annual flat energy prices analyzed were $50/MWh, $63/MWh, and $100/MWh.

2.2.8 Results from Risk Analysis Model. Summaries of the average annual net revenues for all 18 fish and wildlife scenarios for FY 2002–2006 from RiskMod for the three different electricity price and two different load levels are reported in Tables 2-13 through 2-18. The prices in these tables are reported in terms of annual flat energy prices in FY 2002. The net revenues reported in these tables do not include revenues from the Load-Based (LB) CRAC, Financial-Based (FB) CRAC, and interest earned on cash reserves, which are computed in the ToolKit model.

Table 2-13: Net Revenue Summary, Slice = 1,600 MW ($ Thousand)

(FY 2002 Avg. Price = $100/MWh, Load Reduction = 0 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	-622,916	-423,120	-297,494	-274,625	-295,388	-382,709
2 - In-River (hi) CWA	-560,470	-381,121	-254,163	-227,436	-247,825	-334,203
3 - Exp Trns	-608,248	-412,786	-287,758	-263,887	-284,341	-371,404
4 - Exp Trns (low)	-573,896	-419,077	-284,159	-260,384	-278,716	-363,246
5 - TrnsPlus	-622,916	-423,120	-297,494	-274,625	-295,388	-382,709
6 - TrnsPlus CWA	-622,916	-423,120	-297,494	-274,625	-295,388	-382,709
7 - 2 LSN	-811,294	-516,638	-392,783	-378,309	-397,965	-499,397
8 - 4 LSN	-884,167	-552,904	-429,794	-418,696	-436,896	-544,491
9 - LSN & JDA	-890,046	-553,452	-429,291	-418,723	-436,368	-545,576
10 - JDA	-622,916	-423,120	-297,494	-274,625	-295,388	-382,709
11 - JDA Spillway	-622,916	-423,120	-297,494	-274,625	-295,388	-382,709
12 - LSN JDA Spillway	-889,803	-554,528	-431,264	-420,643	-438,512	-546,950
13 - LSN & JDA CWA	-1,078,741	-650,103	-518,909	-518,798	-534,563	-660,223
14 - 2 LSN - Adj	-637,411	-430,389	-304,773	-282,713	-303,331	-391,723
15 - 4 LSN - Adj	-638,191	-430,792	-305,166	-283,144	-303,761	-392,211
16 - LSN & JDA - Adj	-636,638	-429,845	-304,215	-282,098	-302,727	-391,105
17 - LSN JDA Spillway - Ad	-638,900	-431,067	-305,448	-283,447	-304,064	-392,585
18 - LSN & JDA CWA - Adj	-843,308	-532,402	-404,934	-392,701	-411,963	-517,061

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

Table 2-14: Net Revenue Summary, Slice = 1,600 MW ($ Thousand)

(FY 2002 Avg. Price = $100/MWh, Load Reduction = 750 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	-149,779	-250,011	-146,597	-101,866	-123,342	-154,319
2 - In-River (hi) CWA	-85,737	-208,668	-103,657	-54,994	-75,154	-105,642
3 - Exp Trns	-132,946	-240,113	-136,232	-90,469	-112,134	-142,379
4 - Exp Trns (low)	-84,825	-235,163	-125,930	-81,480	-102,051	-125,890
5 - TrnsPlus	-149,779	-250,011	-146,597	-101,866	-123,342	-154,319
6 - TrnsPlus CWA	-149,779	-250,011	-146,597	-101,866	-123,342	-154,319
7 - 2 LSN	-332,978	-348,163	-244,578	-207,309	-226,233	-271,852
8 - 4 LSN	-405,516	-386,054	-282,252	-248,092	-266,106	-317,604
9 - LSN & JDA	-411,089	-385,800	-282,604	-248,644	-266,590	-318,945
10 - JDA	-149,779	-250,011	-146,597	-101,866	-123,342	-154,319
11 - JDA Spillway	-149,779	-250,011	-146,597	-101,866	-123,342	-154,319
12 - LSN JDA Spillway	-411,231	-387,463	-284,446	-250,607	-268,468	-320,443
13 - LSN & JDA CWA	-603,625	-482,760	-373,867	-348,983	-367,815	-435,410
14 - 2 LSN - Adj	-163,831	-257,674	-154,170	-110,039	-131,303	-163,404
15 - 4 LSN - Adj	-164,588	-258,098	-154,577	-110,475	-131,732	-163,894
16 - LSN & JDA - Adj	-163,032	-257,143	-153,641	-109,445	-130,745	-162,801
17 - LSN JDA Spillway - Ad	-165,205	-258,408	-154,897	-110,798	-132,064	-164,274
18 - LSN & JDA CWA - Adj	-368,517	-364,805	-258,386	-223,172	-242,236	-291,423

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

Table 2-15: Net Revenue Summary, Slice = 1600 MW ($ Thousand)

(FY 2002 Avg. Price = $148/MWh, Load Reduction = 0 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	-738,778	-432,774	-295,041	-273,951	-293,961	-406,901
2 - In-River (hi) CWA	-649,341	-380,856	-251,562	-226,283	-246,586	-350,925
3 - Exp Trns	-717,193	-419,815	-285,272	-263,133	-282,970	-393,677
4 - Exp Trns (low)	-664,008	-428,015	-281,968	-259,081	-276,938	-382,002
5 - TrnsPlus	-738,778	-432,774	-295,041	-273,951	-293,961	-406,901
6 - TrnsPlus CWA	-738,778	-432,774	-295,041	-273,951	-293,961	-406,901
7 - 2 LSN	-1,023,225	-552,078	-390,248	-376,394	-396,882	-547,765
8 - 4 LSN	-1,133,657	-598,433	-427,292	-416,717	-435,821	-602,384
9 - LSN & JDA	-1,143,209	-599,164	-426,814	-416,730	-435,400	-604,264
10 - JDA	-738,778	-432,774	-295,041	-273,951	-293,961	-406,901
11 - JDA Spillway	-738,778	-432,774	-295,041	-273,951	-293,961	-406,901
12 - LSN JDA Spillway	-1,142,429	-600,540	-428,791	-418,652	-437,494	-605,581
13 - LSN & JDA CWA	-1,428,459	-722,502	-516,489	-517,410	-533,427	-743,657
14 - 2 LSN - Adj	-760,627	-442,069	-302,288	-281,947	-301,929	-417,772
15 - 4 LSN - Adj	-761,780	-442,577	-302,681	-282,379	-302,359	-418,355
16 - LSN & JDA - Adj	-759,541	-441,383	-301,723	-281,324	-301,324	-417,059
17 - LSN JDA Spillway - A	-762,861	-442,926	-302,958	-282,678	-302,661	-418,817
18 - LSN & JDA CWA - Ad	-1,071,926	-572,146	-402,355	-390,712	-410,999	-569,628

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

Table 2-16: Net Revenue Summary, Slice = 1600 MW ($ Thousand)

(FY 2002 Avg. Price = $148/MWh, Load Reduction = 750 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	30,294	-176,014	-144,144	-101,192	-121,916	-102,595
2 - In-River (hi) CWA	122,091	-124,925	-101,056	-53,841	-73,915	-46,329
3 - Exp Trns	55,080	-163,606	-133,746	-89,715	-110,762	-88,550
4 - Exp Trns (low)	128,625	-157,612	-123,739	-80,177	-100,273	-66,635
5 - TrnsPlus	30,294	-176,014	-144,144	-101,192	-121,916	-102,595
6 - TrnsPlus CWA	30,294	-176,014	-144,144	-101,192	-121,916	-102,595
7 - 2 LSN	-246,496	-301,170	-242,043	-205,394	-225,150	-244,051
8 - 4 LSN	-356,432	-349,577	-279,750	-246,114	-265,031	-299,381
9 - LSN & JDA	-365,531	-349,296	-280,127	-246,651	-265,622	-301,445
10 - JDA	30,294	-176,014	-144,144	-101,192	-121,916	-102,595
11 - JDA Spillway	30,294	-176,014	-144,144	-101,192	-121,916	-102,595
12 - LSN JDA Spillway	-365,320	-351,413	-281,974	-248,616	-267,450	-302,955
13 - LSN & JDA CWA	-656,462	-473,023	-371,447	-347,594	-366,679	-443,041
14 - 2 LSN - Adj	9,099	-185,807	-151,686	-109,273	-129,901	-113,514
15 - 4 LSN - Adj	7,981	-186,342	-152,093	-109,710	-130,330	-114,099
16 - LSN & JDA - Adj	10,224	-185,137	-151,149	-108,672	-129,343	-112,815
17 - LSN JDA Spillway - A	7,037	-186,736	-152,407	-110,028	-130,661	-114,559
18 - LSN & JDA CWA - Ad	-300,410	-322,347	-255,808	-221,183	-241,272	-268,204

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

Table 2-17: Net Revenue Summary, Slice = 1,600 MW ($ Thousand)

(FY 2002 Avg. Price = $225/MWh, Load Reduction = 0 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	-942,863	-473,243	-291,933	-271,945	-292,727	-454,542
2 - In-River (hi) CWA	-810,774	-393,564	-248,378	-224,571	-245,046	-384,467
3 - Exp Trns	-909,888	-452,650	-282,262	-261,188	-281,759	-437,549
4 - Exp Trns (low)	-824,188	-465,110	-279,198	-258,130	-276,122	-420,550
5 - TrnsPlus	-942,863	-473,243	-291,933	-271,945	-292,727	-454,542
6 - TrnsPlus CWA	-942,863	-473,243	-291,933	-271,945	-292,727	-454,542
7 - 2 LSN	-1,382,778	-666,945	-386,790	-375,122	-395,311	-641,389
8 - 4 LSN	-1,552,749	-742,699	-423,611	-415,395	-434,298	-713,750
9 - LSN & JDA	-1,568,057	-744,778	-423,140	-415,373	-433,814	-717,032
10 - JDA	-942,863	-473,243	-291,933	-271,945	-292,727	-454,542
11 - JDA Spillway	-942,863	-473,243	-291,933	-271,945	-292,727	-454,542
12 - LSN JDA Spillway	-1,566,518	-746,528	-425,106	-417,302	-435,938	-718,278
13 - LSN & JDA CWA	-2,010,116	-946,310	-512,244	-515,956	-531,464	-903,218
14 - 2 LSN - Adj	-976,630	-488,243	-299,156	-280,006	-300,677	-468,942
15 - 4 LSN - Adj	-978,384	-489,048	-299,549	-280,437	-301,107	-469,705
16 - LSN & JDA - Adj	-975,029	-487,200	-298,594	-279,387	-300,075	-468,057
17 - LSN JDA Spillway - Adj	-980,055	-489,624	-299,829	-280,738	-301,412	-470,332
18 - LSN & JDA CWA - Adj	-1,458,059	-699,970	-398,810	-389,423	-409,376	-671,127

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

Table 2-18: Net Revenue Summary, Slice = 1,600 MW ($ Thousand)

(FY 2002 Avg. Price = $225/MWh, Load Reduction = 750 MW)

Alternative	FY 2002	FY 2003	FY 2004	FY 2005	FY 2006	5 Yr Average
1 - In-River (low)	303,192	18,172	-141,036	-99,186	-120,681	-7,908
2 - In-River (hi) CWA	438,872	96,538	-97,872	-52,128	-72,375	62,607
3 - Exp Trns	341,038	37,893	-130,735	-87,770	-109,552	10,175
4 - Exp Trns (low)	457,720	47,914	-120,969	-79,226	-99,457	41,197
5 - TrnsPlus	303,192	18,172	-141,036	-99,186	-120,681	-7,908
6 - TrnsPlus CWA	303,192	18,172	-141,036	-99,186	-120,681	-7,908
7 - 2 LSN	-125,071	-184,798	-238,586	-204,123	-223,579	-195,231
8 - 4 LSN	-294,288	-263,803	-276,069	-244,791	-263,508	-268,492
9 - LSN & JDA	-308,906	-264,277	-276,453	-245,294	-264,036	-271,793
10 - JDA	303,192	18,172	-141,036	-99,186	-120,681	-7,908
11 - JDA Spillway	303,192	18,172	-141,036	-99,186	-120,681	-7,908
12 - LSN JDA Spillway	-308,234	-267,202	-278,288	-247,266	-265,895	-273,377
13 - LSN & JDA CWA	-759,609	-466,427	-367,202	-346,141	-364,716	-460,819
14 - 2 LSN - Adj	270,421	2,383	-148,554	-107,332	-128,649	-22,346
15 - 4 LSN - Adj	268,719	1,536	-148,961	-107,768	-129,078	-23,110
16 - LSN & JDA - Adj	272,081	3,402	-148,020	-106,735	-128,094	-21,473
17 - LSN JDA Spillway - Adj	267,256	890	-149,278	-108,088	-129,412	-23,727
18 - LSN & JDA CWA - Adj	-208,285	-219,580	-252,262	-219,894	-239,649	-227,934

Revenue from LB CRAC and FB CRAC are not included in these Net Revenues.

The net revenue risk estimated by RiskMod is an input into the ToolKit Model. The Toolkit Model uses the net revenue risk estimated by RiskMod, the net revenue risk estimated by the NORM model, and additional adjustments to net revenues from the LB CRAC, FB CRAC, and interest earned on cash reserves to calculate the TPP.

CHAPTER 3: NO-SLICE RISK ANALYSIS

3.1 Introduction

In contrast with the initial Supplemental Proposal (*see* WP-02-E-BPA-67, at Chapter 3), BPA did not perform the No-Slice Risk Analysis for the Final Supplemental Proposal. The purpose of performing the No-Slice Risk Analysis in the initial Supplemental Proposal was to assess whether offering the Slice product shifts costs to non-Slice customers and/or shifts risk to the Treasury (or to taxpayers). The results of the cost-shift analysis indicated that Slice does not shift costs to non-Slice customers or shift risk to taxpayers over a wide range of electricity prices, Slice product purchase levels, and load reduction levels. *See* WP-02-E-BPA-67, at Chapter 5.8.

BPA agreed to perform the Cost-Shift Analysis prior to the date that Priority Firm Power customers had to make the final decisions on the amount and type of requirements products, including Slice, that they would purchase in Fiscal Year 2002–2006. Given that these final decisions have been made and the contracts signed, there is no longer a need to perform the No-Slice Risk Analysis in the Final Supplemental Proposal.

CHAPTER 4: SLICE AUGMENTATION COST ANALYSIS

4.1 Introduction and Overview of Chapter

In the May Proposal, BPA adopted an approach to the financial portion of the Investor-Owned Utilities (IOU) Residential Exchange Program Settlements (REP Settlement). Because of subsequent changes to the financial portion of the REP Settlement, as described in Doubleday, *et al.*, WP-02-E-BPA-74, BPA believes that the approach described in the May Proposal is no longer appropriate to assure that Slice purchasers pay their proportionate share of the financial portion of the REP Settlement.

4.2 Purpose of the Proposed Modifications

The proposed modification is intended to assure that Slice purchasers continue to pay their proportionate share of the financial part of the REP Settlement. In order to assure this result, BPA is proposing a monthly adjustment to a Slice purchaser's bill.

4.3 Approach to the Slice Rate Calculation in the May Proposal

A basic tenet of the Slice product is that Slice purchasers pay a percentage of BPA's costs proportionate to the percentage of the generation output of the Federal Columbia River Power System that the Slice purchaser elects to purchase. Wholesale Power Rate Development Study, WP-02-E-BPA-05, at 42. The costs considered by the Block and Slice Power Sales Agreements are referred to collectively as the Slice Revenue Requirement. *Id.* The Slice Revenue Requirement consists of all the line items identified in the generation revenue requirement, with certain limited exceptions. Mesa, *et al.*, WP-02-E-BPA-32, at 5. The Slice Revenue Requirement includes costs associated with the financial portion of the REP Settlement.

4.4 Slice Portion of Increased Residential Exchange Program Settlement

As presented in Chapter 6 of this study, BPA's Supplemental Proposal has the effect of increasing the value of the financial portion of the REP Settlement of the Residential Exchange Program. A proportionate share of the increased cost of the cash portion of the REP Settlement will be assessed to purchasers of the Slice product. BPA is proposing to include this as a monthly adjustment to the monthly bill for each Slice purchaser.

The monthly adjustment per one-percent Slice is proposed to be:
[Incremental amount of REP Settlement costs above the May Proposal/12/100] = $ per month per one-percent Slice.

CHAPTER 5: RISK MITIGATION

5.1 Introduction

This chapter describes the changes incorporated in the Supplemental Proposal to the risk mitigation tools and modeling that were presented in the May 2000 Final Power Rate Proposal (May Proposal). Since the publication of the May Proposal, significant changes in West Coast power markets and unanticipated high requests for power required BPA to reassess its risk profile and develop an even more robust risk mitigation package. As explained in Chapter 1 of this document, due to higher market prices BPA now expects both increased demand and higher costs for augmentation purchases to meet that demand than previously projected. The combination of an unanticipated increase in loads with higher and increased volatility in market prices greatly diminished the probability that the rates reflected in the May Proposal would fully recover generation function costs. Absent a change to the proposed rate package, Treasury Payment Probability (TPP) would be reduced to an unacceptable level.

In December 2000, BPA released the 2002 Amended Power Rate Proposal (Amended Proposal). The Amended Proposal addressed the additional risks that had materialized following the release of the May Proposal. It included updated forecasts of market prices and expected reserves, and replaced the Cost Recovery Adjustment Clause (CRAC) that was in the May Proposal with a more robust, three-component CRAC to mitigate risks of an increasingly volatile market. Since December, market prices have continued to rise to levels well beyond those forecast in the fall of 2000. At the same time, the Pacific Northwest has been experiencing a drought that has left reservoirs at levels well below average, thereby constraining the generation capacity of the FCRPS both in the current year and into the next fiscal year. This Supplemental Proposal addresses these more recent increases in risks and prices by adopting the same general approach as the Amended Proposal (*i.e.*, a three-component CRAC) but modifying some of the specific rate-making provisions. In order to accomplish this, several modifications have been made to the risk mitigation methodology as well as to the structure of the ToolKit model. These modifications are detailed in the text that follows.

5.2 Treasury Payment Probability

The Supplemental Proposal, like the May and Amended Proposals, is consistent with Fish and Wildlife Funding Principles (Principles) Nos. 3 and 4, which relate to BPA's TPP. Principle No. 3 states:

> "Bonneville will demonstrate a high probability of Treasury payment in full and on time over the five-year period.
>
> - A 100 percent probability of Treasury payment is not achievable, but BPA's new rates must be designed to maintain or improve TPP, even in view of the range of fish costs.
> - BPA will demonstrate a probability of Treasury payment in full and on time over the five-year rate period at least equal to the 80 percent level established in the last rate case and will seek to achieve an 88 percent level." *See* the Principles, Volume 1, Chapter 13 of Revenue Requirement Study Documentation, May Proposal, WP-02-FS-BPA-02A.

In the May Proposal, BPA designed and proposed risk mitigation tools to achieve an 88 percent TPP for the generation function. An 88 percent TPP continues to be BPA's goal. Because the design of Load-Based (LB) CRAC calls for adjustments based on actual levels of augmentation and actual market prices, the Supplemental Proposal includes a range of TPPs rather than a point estimate. Several scenarios were modeled to demonstrate the impacts of different levels of market price and load reduction on the amount of revenues to be collected. The scenarios that have been modeled result in TPPs from 81.6 percent to 88.3 percent, which still meet the criteria called for in the Principles. *See* Chapter 5.6 of this Study, and Burns and Berwager, WP-02-E-BPA-70.

Principle No. 4 states: "Given the range of potential fish and wildlife costs, BPA will design rates and contracts which will position BPA to achieve similarly high Treasury payment probability for the post-2006 period by building financial reserve levels and through other mechanisms." Consistent with this Principle, the expected value of reserve levels at the end of Fiscal Year (FY) 2006 was $1.2 billion in the May Proposal, without modeling Dividend Distribution Clause (DDC) distributions. In the scenarios modeled for the Supplemental Proposal which include impacts of Slice loads, the expected value of ending reserves, including modeling DDC distributions, are $1.1 billion.

5.3 Risk Mitigation Tools

The Supplemental Proposal incorporates the same general risk mitigation tools as the May and Amended Proposals. In addition to those tools used in the development of the May Proposal, two new tools, a LB CRAC and a Safety-Net (SN) CRAC, were added in the Amended Proposal to address the higher level of risk due to system augmentation and market volatility. The Supplemental Proposal contains updates and revisions to some of these tools. *See* WP-02-FS-BPA-02A, at 266-267; WP-02-E-BPA-61, at 6-9 through 6-11; WP-02-FS-BPA-10, Chapter 5.

5.3.1 Fiscal Year 2002 Start of Year Financial Reserves. Starting financial reserves include cash in the Bonneville Fund and deferred borrowing balance, if any, attributable to the generation function. The risk-adjusted expected value for starting reserves is $429 million at the beginning of FY 2002; the range is from about -$394 million to about $1,335 million.

5.3.2 Credits under the Fish Cost Contingency Fund. There has been no change in terms and conditions of access from the May Proposal. The projected balance at the beginning of FY 2002 is $158 million, reflecting a projected use of $167 million in FY 2001 out of the starting 2001 balance of $325 million.

5.3.3 Planned Net Revenues for Risk. There has been no change from the May Proposal. Planned Net Revenues for Risk (PNRR) averages $98 million per year and annual internal cash flows, which are available for risk, average $22.6 million per year. PNRR is a component of the revenue requirement, and as BPA is not changing the revenue requirement in the Supplemental Proposal, it is not changing the PNRR.

5.3.4 Cost Recovery Adjustment Clauses. The CRACs are temporary upward adjustments to posted power prices if certain conditions occur. Although the May Proposal contained a single CRAC mechanism to deal with fluctuations in BPA's financial situation, the Amended Proposal contained three CRAC mechanisms: the LB CRAC would be implemented if augmentation load exceeded the amount forecast in the original 2002 rate case; the Financial-Based (FB) CRAC was designed to trigger if forecasted accumulated net revenues (ANR) at the beginning of a year fell below a threshold level; and the SN CRAC was triggered by a missed payment to Treasury or any other creditor, or a forecast of a missed payment, and was designed to prevent further deferrals. These three CRAC mechanisms have been adjusted since the Amended Proposal as described below.

The FB and SN CRACs apply to power customers under these firm power rate schedules: Priority Firm Power (PF) Preference [(PF excluding Slice), Exchange Program, and Exchange Subscription], Industrial Firm Power (IP-02), including purchases under the Industrial Firm Power Targeted Adjustment Charge (IPTAC) and Cost-Based Index Rate, Residential Load

(RL-02), New Resource Firm Power (NR-02), and Subscription purchases under Firm Power Products and Services (FPS). The CRACs do not apply to power sales under Pre-Subscription contracts or Irrigation Mitigation sales. In the Supplemental Proposal, the financial portion of the Residential Exchange Program Settlement (REP Settlement) is subject only to the SN CRAC, and Slice purchases are not subject to the FB or SN CRACs, but are subject to the LB CRAC and the Slice provisions for the LB CRAC true-up. *See* General Rate Schedule Provisions, Appendix to Administrator's Final Record of Decision, WP-02-A-09 for a detailed description of the rates to which the CRACs apply. *See* also Chapter 5.7 which describes the LB CRAC Methodology.

5.3.4.1 Load-Based Cost Recovery Adjustment Clause. The LB CRAC is a percentage rate adjustment based on BPA's cost of augmentation. It is designed to cover the net cost of augmenting BPA's system. The Amended Proposal included a flat percentage LB CRAC to be applied throughout the rate period. Because BPA will be acquiring this additional power in a highly volatile market, it is not possible to accurately forecast the cost of purchasing this power over the entire five-year rate period. Accordingly, the LB CRAC has been redesigned in the Supplemental Proposal to be responsive to changes in the market price of power. BPA will establish the LB CRAC percentage and resulting adjustment to the rates that will apply to the sale of products under rates subject to the LB CRAC each six-months of the rate period.

The LB CRAC amount will be adjusted every six months during the rate period, for October through March, and for April through September. Approximately 90 days before the beginning of each six-month period, there will be a public process to determine the amount of the LB CRAC adjustment for the upcoming six months. The adjustment will be based on updated market prices and augmentation loads and will be applied to each customer's power bill for the six-month period.

Approximately 90 days after the end of each six-month period, BPA will true-up the LB CRAC for the prior six-month period based on actual augmentation purchases during the period. *See* Chapter 5.7 of this Study for a detailed discussion of the mechanics of the LB CRAC and Slice adjustments. *See* General Rate Schedule Provisions, Appendix, WP-02-A-09.

5.3.4.2 Financial-Based Cost Recovery Adjustment Clause. In the Supplemental Proposal, the FB CRAC is structured in substantially the same way as the single CRAC in the May Proposal, with two notable exceptions described below. Both CRACs are designed to trigger when ANR at the end of the prior year decline below a predetermined threshold. Once triggered, both CRACs result in a percentage rate increase for a 12-month period, to collect revenues equal to either the amount by which the ANR falls below the threshold or an annual cap, whichever amount is smaller. The thresholds in the May Proposal were the prior year-end ANR equivalent of $300 million in reserves for FY 2002 and 2003, and $500 million for FY 2004-2006. The caps were $125 million for FY 2002, $135 million for FY 2003, $150 million for FY 2004-2005, and $175 million for FY 2006.

The Supplemental Proposal changes the FB CRAC design in the following ways. First, FY 2002 FB CRAC is allowed to collect whatever amount of additional ANR would have been needed to raise ANR to the threshold value for that year ($300 million in terms of cash reserves): the annual cap on FB CRAC revenue collection for FY 2002 was removed. The annual thresholds and caps for the remainder of the rate period, FY 2003-2006, remain the same as those set in the May Proposal, and the amount collected cannot exceed the cap in those years. Second, the timing of the collection of FB CRAC has changed. In the May Proposal, the determination of whether the FB CRAC threshold had been reached was based on audited actual financial data available in January, and collection was to be made over a 12-month period beginning in April. By contrast, the Amended Proposal called for collecting the full amount in the four months between March and June. The Supplemental Proposal reverts to the collection of the FB CRAC over a 12-month period. However, collection would begin in October following an initial determination made in August after the Third Quarter Review.

For FY 2002, the FB CRAC increase is calculated by determining the Revenue Amount (the amount to be collected under the FB CRAC) and dividing by the total generation revenue (not including LB CRAC) for loads subject to CRAC for FY 2002, based on the then most current revenue forecast. For FY 2003-2006, FB CRAC Revenue Basis is the total generation revenue (not including LB CRAC) for the loads subject to FB CRAC plus Slice loads for the FY in which the FB CRAC implementation begins, based on the then most current revenue forecast. Each non-Slice product's total charge for energy, demand, and load variance will be increased by this CRAC percentage amount in each of the 12 billing months in the fiscal year.

A true-up will be made during any year in which the FB CRAC is implemented, if the prior year's audited actual net revenues differ by more than $5 million from the amount forecasted in August. The adjustment will be based on the difference between the originally-calculated FB CRAC Revenue Amount and the Revenue Amount calculated using the audited actual ANR. This difference will be divided by the generation revenue (not including LB CRAC) for the loads subject to FB CRAC, as forecasted for power deliveries for April through September. The resulting adjustment will be applied to each customer's bills for April through September of the fiscal year. *See* General Rate Schedule Provisions, Appendix, WP-02-A-09.

5.3.4.3 Safety-Net Cost Recovery Adjustment Clause. The third component, SN CRAC, has been revised in two ways since the Amended Proposal. The SN CRAC is now designed to trigger when BPA forecasts a 50 percent or higher probability of missing a payment to Treasury or other creditor any time within the remainder of the current fiscal year, or upon the occurrence of a missed payment to Treasury or other creditor. If, even with implementation of the LB and FB CRACs, this threshold is reached, the SN CRAC process begins, enabling posted power rates for Subscription sales to be adjusted upward through modification of FB CRAC parameters. If the SN CRAC does trigger, BPA will propose changes to the FB CRAC parameters that will, to the extent market and other risk factors allow, achieve a high probability that the remainder of Treasury payments during the rate period will be made in full. BPA's proposal could include changes to the Revenue Amount (the amount to be collected through the FB CRAC), the duration (the length of time the FB CRAC would be in place, which could be for more than 1 year), and the timing of collection.

The second change to the SN CRAC design is that an expedited process under section 7(i) will be conducted in which BPA will demonstrate the need for such an adjustment. At the end of the 7(i) process, the Administrator will make a final decision on the SN CRAC based on the record. The decision will be submitted to the Federal Energy Regulatory Commission (FERC) for review and confirmation. *See* General Rate Schedule Provisions, Appendix, WP-02-A-09.

5.4 Dividend Distribution Threshold

BPA's Supplemental Proposal retains the DDC mechanism for distributing "dividends" to certain stakeholders if Audited Accumulated Net Revenues (AANR) for the prior year reach the DDC Threshold. However, the mechanics of how the DDC will operate have changed since the publication of the Amended Proposal.

As in the May Proposal, the first $15 million of AANR exceeding the threshold will be allocated to qualifying Conservation and Renewable purposes. The remainder of any excess revenues will automatically be refunded to customers, rather than having a separate public process to determine how dividends should be allocated. The threshold for any fiscal year will be adjusted upward in the event that:

- There has been a Power System Emergency during the fiscal year, and BPA has agreed to provide additional funding to mitigate the impact of the emergency operations on fish and wildlife, and to the extent that BPA has not spent the additional emergency-related funding during that fiscal year, the threshold for that year will be increased by that amount; and/or
- To the extent that BPA fish and wildlife direct program costs previously budgeted for expenditure in that fiscal year were not spent in that fiscal year and a need for them continues, the threshold for that year will be increased by that amount.

Due to the automatic nature of the DDC, threshold values have been raised since the May and Amended Proposals. They are now the AANR equivalent of $1.7 billion in ending reserves for FY 2002 (for distribution in FY 2003), $1.5 billion for FY 2003, and $1.2 billion for FY 2004-2005. There will be no DDC distribution in FY 2002, the first year of the rate period. In addition, the financial portion of the Exchange settlement (900 average megawatt (aMW)) will be counted as loads and will participate in DDC distributions.

The determination of whether the AANR exceeds the DDC threshold will be made in January of each eligible year in the rate period (FY 2003-2006), after audited actual financial data is available. The amount of dividends is the difference between AANR and the threshold (as adjusted). The first $15 million will go to qualifying Conservation and Renewables Discount (C&R Discount) participants. The remaining amount (Power Customer DDC Amount) will be converted to a percentage by dividing it by the DDC Customer Revenue Amount, which is the total revenues paid to BPA by customers eligible for the DDC since the beginning of the rate period or the last DDC distribution, whichever is later. These revenues will include the financial portion of the REP Settlement at the applicable Residential Load (RL) rate. This percentage will be applied to the DDC Customer Revenue Amount for each power customer subject to the DDC to arrive at the amount to be rebated on power bills for each of the included power customers during the 12-month period beginning in April, or the six-month period beginning in April for FY 2006. *See* General Rate Schedule Provisions, Appendix, WP-02-A-09.

5.5 ToolKit and Generation Risk Mitigation Modeling

The ToolKit model is used to determine the probability of making all planned Treasury payments during the five-year rate period given the risks identified in two other models, Risk Analysis Model (RiskMod) and Non-Operating Risk Model (NORM), and the risk mitigation tools. Specifically, ToolKit receives two streams of net revenues and sums these to arrive at a distribution that reflects both operating and non-operating risks. RiskMod produces the stream of net revenues reflecting operating risk, whereas NORM produces the stream of net revenues reflecting non-operating risks. *See* Risk Analysis Study and Documentation, WP-02-FS-BPA-03 and WP-02- FS-BPA-03A for a description of RiskMod and NORM and the Revenue Requirement Study Documentation, Volume 1, WP-02-FS-BPA-02A, at 268-270 for a fuller description of the modeling system.

Another version of the ToolKit model is used to produce a distribution of net revenues for the remaining year of the current rate period (FY 2001). This version uses the output of the Short-Term Evaluation and Analysis Model (STREAM) model used in the 1996 Rate Case to assess operating risks for FY 2001, and a current rate period version of NORM to assess the potential impact of two non-operating risks in FY 2001. For the Supplemental Proposal, the output of STREAM was modified to better reflect BPA’s current outlook.

For the Supplemental Proposal, ToolKit was calibrated to a lower FY 2002 starting reserves value than in the May Proposal. In December, a new set of 300 starting reserves values were generated by ToolKit, calibrated to forecasts reported in BPA's Second Quarter Review for FY 2001. Additionally, the $50 million deferral floor was turned off so that the FY 2002–2006 ToolKit would be reading reserves values that could include negative cash balances; for example, if BPA exercised a note with Treasury to cover cash requirements and needed to pay off the note. It is this amount that the uncapped FY 2002 FB CRAC would have to pay off to reestablish a $300 million ending reserves level. FY 2002 starting reserve balances in the 300 games averaged $429 million.

- Both the RiskMod and NORM distributions for the FY 2002–2006 period were modified to reflect two sets of changes from the May Proposal. First, because the percentage of system output to be purchased by Slice customers is now known, the net revenues deviation in both RiskMod and NORM were adjusted to reflect the 22.63 percent of operating and non-operating risks absorbed by the Slice customers. The net revenues developed in RiskMod also reflected a revised forecast of market prices, and larger system augmentation required to meet the loads placed on BPA by customers who have signed Subscription contracts.
- Two components of the CRAC were modeled in ToolKit.
    1. The LB CRAC is designed to cover the net cost of augmenting BPA's system to meet the additional 1,518 aMW of load. Because BPA will be acquiring this additional power in a highly volatile market, it is not possible to accurately forecast the cost of purchasing this power over the entire five-year rate period. Accordingly, the LB CRAC has been designed to be responsive to changes in the market price of power. The internal logic of the ToolKit was modified in order to model the LB CRAC as it is currently designed. New inputs were added: the annual market price weighted by BPA's monthly augmentation need; the net costs of acquiring that augmentation; and the revenue bases for the FB and LB CRACs. Additional outputs were calculated to show statistics on the LB and FB CRACs.

2. The FB CRAC is structured and modeled in substantially the same way as in the May Proposal with two notable exceptions. First, the annual cap on new revenue collection for FY 2002 was removed: ToolKit now models the FY 2002 FB CRAC so that it collects whatever amount of additional revenues are needed to raise reserves to the $300 million threshold value for that year, and the amount to be collected is not reduced by the fraction that Slice load makes up of the total Slice loads plus loads subject to the FB CRAC. The annual thresholds and caps for the remainder of the rate period, FY 2003-2006, remain the same. Second, the ToolKit reflects the change in the timing of the collection of FB CRAC. Collection would begin in October following an initial determination, based on forecasts, made in August after the Third Quarter Review.

- Because the value of the Investor-Owned Utility (IOU) REP Settlement has been revised to reflect a market price of $38 rather than $28.1 per megawatthour (MWh), an additional annual expense of $60 million was entered, representing the additional costs less the 22.63 percent share of that expense that would be paid by Slice customers.
- SN CRAC was not modeled in ToolKit because its parameters will not be fully defined until it triggers and therefore cannot be modeled. Additionally, if it could be modeled, it would not significantly affect the calculation of TPP as TPP has historically been defined. TPP reflects the probability that no Treasury payments will be missed during the five-year rate period. The SN CRAC is not likely to trigger in time to prevent a missed Treasury payment, but is instead more likely to help avoid a second miss.

Because the DDC is now designed to operate automatically, these thresholds can be modeled in ToolKit simply as a “reverse CRAC.” The DDC is modeled so that it triggers when ending cash reserves exceed $1.7 billion in FY 2002 (for distribution in FY 2003), $1.5 billion in FY 2003, and $1.2 billion in FY 2004-2005. There will be no DDC distribution in FY 2002, the first year of the rate period.

When implemented, the DDC will be triggered by actual ANR values comparable to the threshold expressed in terms of cash. These AANR equivalents have been recalibrated based on updated financial data. The threshold is $993 million for the end of FY 2002 (*i.e.*, for possible distribution starting in FY 2003), $735 million for the end of FY 2003, and $401 million for the end of both FY 2004 and 2005.

5.6 Risk Mitigation ToolKit Results

For the Supplemental Proposal, ToolKit was run a total of 6 times. This was done to demonstrate the impacts of different levels of market price and load reduction on the amount of revenues to be collected under the LB CRAC. Since, for the Final Supplemental Proposal, the amount of load Slice customers would place on BPA was known, BPA did not repeat the Cost Shift Analysis carried out for the initial Supplemental Proposal. *See* Chapter 3 of this Study.

Table 5-1 makes comparisons of the relative rate impacts of LB CRAC, FB CRAC, and DDC on Slice and non-Slice customers given different FY 2002 price levels and load reduction assumptions.

Table 5-1: Treasury Payment Probability Analyses

ToolKit run	*1*	*2*	*3*	*4*	*5*	*6*
FY 2002 market price	100	100	148	148	225	225
Load reduction (relative to Amended Proposal)	0	750	0	750	0	750
Treasury Payment Probability	81.6%	81.6%	85.7%	85.7%	88.3%	88.3%
Expected value ending 2006 reserves	1,003	1,004	1,087	1,087	1,147	1,147
2002 net augmentation cost	1,154	622	1,649	793	2,448	1,070
2002 – 2006 total net augmentation cost	3,052	1,782	3,682	1,999	4,858	2,403
2002 – 2006 average frequency of FB CRAC	24%	24%	18%	18%	15%	15%

The table summarizes the results of running ToolKit for six distinct combinations of conditions.

	sets of			load			ToolKit
3	market	X	**2**	reduction	=	**6**	Alternatives
	prices			levels			

where:

- market price levels for FY 2002 are set at $100, $148, and $225/MWh;
- load reduction levels are either 0 or 750 aMW. Load reduction = 0 indicates that all purchases and buy-downs signed by June 1, 2001 are incorporated; load reduction = 750 reflects a decrease in BPA loads of 750 aMW at no cost.

The table compares five-year TPP, first year rate increase due to LB and FB CRAC, average rate increase due to LB and FB CRAC, average rate increase due to LB and FB CRAC including the offsetting effects of the DDC, and FY 2006 average ending reserves. These values are reported for each of six specific market price/load reduction combinations. Attachments 2-7 to the documentation for this Study present the summary ToolKit outputs for each of the six alternatives modeled. *See* WP-02-FS-BPA-10. (Note: Unlike the May and Amended Proposals, the ToolKit runs represented in the table reflect the effects of the DDC.)

5.7 Load-Based Cost Recovery Adjustment Clause Methodology

5.7.1 Introduction and Overview. This section describes BPA's LB CRAC Methodology for the Supplemental Proposal. The LC CRAC methodology describes how BPA will recover augmentation costs on loads subject to the LB CRAC which includes Slice.

Chapter 5.7.2 addresses the rationale for the proposed changes. Chapter 5.7.3 summarizes the approach to recovering augmentation costs in the May and Amended Proposals. Chapter 5.7.4 explains how BPA will determine the Monthly Augmentation Amounts (AAMT). Chapter 5.7.5

describes BPA's LB CRA methodology. Chapter 5.7.6 elaborates on BPA's proposed approach to determining the amount of over- or under-collection of augmentation costs from application of the LB CRAC.

5.7.2 Purpose of the Proposed Modifications. In the May Proposal, BPA used the five-year flat block forecast of $28.10/MWh to calculate BPA's augmentation costs. Using a price forecast has the inherent problem of being an imprecise approximation of prices, since the actual prices will rarely reflect the forecast of prices. In the May Proposal, BPA was willing to accept the risk associated with using a price forecast in calculating augmentation costs because the power market was perceived to be relatively stable. However, because the wholesale power market is significantly higher and more volatile than it was when the forecast in the May Proposal was developed, the use of a forecast to price the augmentation presents a significantly greater financial risk for BPA. These market changes are described in Conger, *et al.*, WP-02-E-BPA-71. BPA is now proposing a methodology that will allow for semiannual changes in rates subject to LB CRAC to provide a method that will more directly allow augmentation costs to be reflected in rates from all purchasers' loads subject to the LB CRAC. The LB CRAC methodology is a redesign of both the LB CRAC and Slice Augmentation Cost methodology that appeared in the Amended Proposal.

5.7.3 Approach to Augmentation Cost Recovery in the May Proposal and the Amended Proposal. In the May Proposal, BPA included expected augmentation costs in the revenue requirements contained in that proposal. In turn, the base rates reflected these augmentation revenue requirements. BPA's Amended Proposal proposed a series of CRAC mechanisms for non-Slice customers. In that proposal, increments in augmentation costs in excess of those included in the May Proposal would have been covered by these CRAC mechanisms for non-Slice customers. A separate method was proposed to recover the proportionate share of BPA's augmentation costs from Slice purchasers.

In the Supplemental Proposal, BPA is modifying the LB CRAC and Slice augmentation methodology so that they are very similar in design. Through a series of semiannual adjustments to the forecast of augmentation costs and after-the-fact true-up adjustments to the forecast based upon subsequent events, BPA is attempting to deal with the risks associated with augmentation expenses in the current market. The major difference between the treatment of the Slice purchasers and non-Slice customers will be the manner in which the after-the-fact true-up is conducted. Because Slice purchasers assume certain risks and take on certain obligations directly through the purchase of the product, the manner in which the adjustment is made is reflected in the Supplemental Proposal.

5.7.4 Establishing the Monthly Augmentation Amount. The Monthly Augmentation Amount (AAMT) is the amount of augmentation that BPA forecasts to use to calculate the LB CRAC percentage. Table 5-2 shows the AAMT that will be used to determine the LB CRACs. For a given month, the AAMT is a constant for all hours in that month.

Table 5-2: Forecast Monthly Acquisition Amounts

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
FY 2002	3159	3469	3736	3864	3799	3508	3425	3411	3311	3376	3362	3268
FY 2003	3142	3434	3689	3633	3565	3280	3177	3165	3081	3141	3125	3035
FY 2004	2899	3194	3436	3412	3337	3069	2993	2980	2897	2957	2946	2859
FY 2005	2846	3146	3392	3442	3376	3093	3016	3003	2918	2981	2972	2884
FY 2006	2818	3116	3359	3360	3293	3013	2920	2904	2820	2883	2868	2779

Over the rate period, BPA will determine if the AAMT amounts needed are different from those in Table 5-2. Documentation and additional explanation for the calculation of the numbers in Table 5-2 is contained in WP-02-E-BPA-69.

5.7.5 LB CRAC Methodology. The discussion in this section describes the calculations BPA will use to determine the LB CRAC.

5.7.5.1 Application. The LB CRAC applies to power customers under the following firm power rate schedules: PF Preference, Exchange Program, and Exchange Subscription; Industrial Firm Power (IP-02), including under the IPTAC and Cost-Based Index Rate; Residential Load (RL-02); New Resource Firm Power (NR-02); and Subscription purchases under FPS, excluding revenues generated by the FB CRAC, SN CRAC, and distributions under DDC. The LB CRAC does not apply to power sales under Pre-Subscription contracts, the financial portion of the Residential Exchange Settlement, or Irrigation Mitigation sales. The LB CRAC does apply to Slice purchases. *See* General Rate Schedule Provisions, Appendix, WP-02-A-09, for a more complete description of the rate schedules to which the LB CRAC applies.

The LB CRAC will apply to a purchaser's bill for purchases under these rate schedules. The first LB CRAC will apply to the six-month period beginning October 2001 and the last LB CRAC will apply to the six-month period beginning April 2006.

5.7.5.2 Process. On or about 90 days prior to the beginning of each six-month period, BPA will establish the LB CRAC percent for the upcoming six-month period. The LB CRAC percent will be determined using the methodology described in WP-02-E-BPA-68.

Approximately 90 days after the end of the most recent six-month period, BPA will determine over- or under-collection of augmentation costs that may have occurred during the most recently completed six-month period. This determination will be made using the methodology described in WP-02-E-BPA-68. BPA will also determine what data require updating from that used to set the LB CRAC percent.

5.7.5.3 Calculations that are performed both before the beginning of a six-month period and after the end of the same six-month period. This section describes BPA's proposed approach to calculations that are both a part of determining the LB CRAC percent before the beginning of a six-month period as well as the determination of whether actual LB CRAC revenues collected during the six-month period are in excess of actual Net Augmentation Cost (NAC) or fall short of actual NAC for the six-month period.

5.7.5.3.1 Determining the Monthly Augmentation Cost. While AAMT is flat for a given month (but may vary in amount between months), the cost of meeting this AAMT will likely vary by diurnal periods within a month.

5.7.5.3.1.1 Determining the Total Cost of Acquisition Pre-Purchases. BPA will maintain records of Acquisition Pre-Purchases (APP) made to meet the AAMT for the month. These data will be maintained in MWh, megawatt (MW), and/or aMW (and their associated costs) for each month separately for Heavy Load Hours (HLH) and Light Load Hours (LLH) and their associated costs.

As BPA makes acquisitions to meet AAMT, the shape of the augmentation and cost, by diurnal period by month, are noted for the term of the acquisition. Acquisitions made at least 120 days in advance of the month in which an LB CRAC takes effect are included in the augmentation tally, irrespective of the duration of that augmentation purchase.

Here are several examples.

Example 1: In May 2001, BPA enters into an acquisition for 100 MW HLH power for six months at $200/MWh.

This acquisition would be entered into the augmentation totals in the June 2001 calculation of the LB CRAC percent that will apply for the six-month period beginning October 2001.

Example 2: BPA enters into an acquisition on May 30, 2001, for 500 aMW for 12 hours at a price of $500/MWh for delivery in October 2001.

These costs will be treated exactly the same as those in Example 1.

Example 3: BPA enters into an acquisition on June 30, 2001, of 100 aMW HLH power at $120/MWh for a 12-month period beginning November 1, 2001.

Since this purchase was not made 120 days prior to October 1, 2001, the cost of this pre-purchase will not appear in the costs used to determine the LB CRAC percent that will apply beginning October 1, 2001. The cost of this pre-purchase does qualify as an APP for meeting AAMT used to determine the LB CRAC percent that will be applied beginning April 1, 2002 and October 1, 2002. After-the-fact, they will be included in the costs used to determine the LB CRAC revenue over- or under-recovery for the following periods: (a) October 1, 2001–March 30, 2002; (b) April 1, 2002–September 30, 2002; and (c) October 1, 2002–March 30, 2003.

After the close of a six-month period, BPA will determine what the diurnal augmentation cost (DIURNALAC) would have been, since the cut-off for a purchase to be considered an APP was 120-days before each separate month, rather than 120-days before the six-month period. This determination will affect the calculation of DIURNALAC.

In addition, BPA will also calculate DIURNALAC using a rule of five days before the end of the month rather than 120 days before the end of the month. This separate determination of DIURNALAC will enter into the Total Cost of Acquisition Pre-Purchases (TCAPP) that is used in determining the over- or under-collection of costs only from non-Slice purchasers. This is discussed further in section 5.7.6.3.

5.7.5.3.1.2 Determining the Diurnal Augmentation Costs. One of the following equations will be used to determine the augmentation costs for each separate diurnal period. The three equations are as follows:

1. If APP > AAMT, Then DIURNALAC = (AAMT/APP) * TCAPP
2. If APP = AAMT, Then DIURNALAC = TCAPP
3. If APP < AAMT, Then DIURNALAC = TCAPP + [(AAMT-APP) * PRICE * Hours]

where:

AAMT = Augmentation Amount (aMW)
APP = Acquisition Pre-Purchases (aMW)
TCAPP = Total Cost of Acquisition Pre-Purchase ($$)
DIURNALAC = Diurnal Acquisition Cost ($$)
PRICE = Price established 120 days prior to the month.

Example: Calculate the diurnal cost of meeting AAMT for October 2001 to determine the LB CRAC percent to go into effect on October 1, 2001. Assume that by June 1, 2001, BPA has entered into agreements for 1,000 aMW HLH power for six months at $200/MWh and 500 aMW of LLH purchases at $120/MWh also for six months. AAMT equals 2,209 aMW for October 2001. Five-day price is $60/MWh on HLH and $40 on LLH. The 120-day price for HLH is $80/MWh and $60/MWh for LLH.

This acquisition would be entered into the augmentation totals for the October 2001 calculation that is a part of the LB CRAC percent for the six-month period beginning October 2001. Here, APP for HLH = 1,000 and APP for LLH = 500. CAPP for HLH = 100*200 *HLH Hours, and CAPP for LLH = 500*120 *LLH Hours. These amounts and costs will be input into formula 3 above for both HLH and LLH since AAMT = 2,209 aMW is greater than the APP for both HLH and LLH. Since the HLH and LLH APP<AAMT, the difference between APP and AAMT is priced at the price established at the end of May.

This same procedure will be performed for each diurnal period for each month. All of the separate DIURNALAC for a six-month period will then be summed to determine the TCAPP for the six-month period.

In this example, the five-day price for augmentation not pre-purchased (PRICE) was not used. When DIURNALAC is determined before the beginning of a six-month period, the 120-day PRICE will be used. When these calculations are being performed after the close of that same six-month period, the 120-day PRICE will first be used. This set of DIURNALAC will be used in subsequent steps for determining the amount of augmentation costs for Slice and non-Slice purchasers. Then, after the amount of Slice and non-Slice LB CRAC revenue over- or under-payment has been established, a separate analysis will be performed using the five-day price in place of the 120-day price in this above example. This amount of DIURNALAC will then result in a different amount of Total Augmentation Cost (TAUGC) in the next step.

5.7.5.3.1.3 Calculating the Total Augmentation Cost. The TAUGC is the sum of Total Pre-Purchase Cost (TPPC) and all monthly option or monthly load buydown costs. When TAUGC is calculated before the beginning of the upcoming six-month period, one TAUGC will be determined using the 120-day rule for determining what qualifies as an APP and the 120-day PRICE for equation 3 in section 5.7.5.3.1.2.

After the close of this same six-month period, a new TAUGC will be determined that will be used to calculate the amount of LB CRAC revenue over- or under-collection from both Slice and non-Slice purchasers. When this TAUGC is determined, the 120-day rule will again be used. A separate TAUGC will also be determined using a five-day rule for defining what constitutes a pre-purchase and the value for PRICE. The TAUGC that results from this replacement of the 120-day rule with the five-day rule will result in a difference between the TAUGC calculated after the close of the six-month period using the 120-day rule and the TAUGC calculated after the close of the six-month period using the five-day rule. Section 5.7.6.3 describes how this difference is assigned to non-Slice purchasers.

This difference between the after-the-fact calculation of TAUGC using the 120-day rule and the after-the-fact calculation of TAUGC using the five-day rule represents the change in cost of meeting AAMT for the six-month period. This cost change may be positive or negative. All of this cost change is an adjustment to the cost responsibility of non-Slice purchasers and the difference between these two calculations is referred to as Difference in Net Augmentation Cost (NACDIFF) appearing in section 5.7.6.2.

5.7.5.3.2 Calculating the Monthly Augmentation Resale Revenues. Monthly Augmentation Resale Revenues (MARR) represent a monthly amount of revenue to BPA on sales from augmentation quantities included in the May Proposal. For augmentation quantities already included in the May Proposal, as defined in Sales of Existing Augmentation Quantity (SALESMAYAUG), resale revenues are to be determined using a rate of $28.10/MWh. For augmentation quantities above those included in the May Proposal, defined as Sales of New Augmentation Quantity (SALESNEWAUG), resale revenues are to be determined using a rate of $19.10/MWh. The formula is as follows:

MARR = (SALESMAYAUG* $28.10) + (SALESNEWAUG * $19.10) where:

SALESMAYAUG = Resale of augmentation of 1,282 aMW not purchased by August 1, 2000, plus the amount of energy at $28.10/MWh melded into the Direct Service Industrial rate and collected through IP sales.

SALESNEWAUG = Resale of augmentation quantity above SALESMAYAUG.

BPA will update SALESMAYAUG and SALESNEWAUG as needed. BPA will also update these numbers when determining any actual LB CRAC revenue over- or under-collection. SALESMAYAUG and SALESNEWAUG may vary due to load loss, including buydown. Such reductions in loads translate into reductions in acquisitions which translates into reductions in acquisition resale revenue.

5.7.5.3.3 Calculating Total Augmentation Resale Revenue. Once a MARR is determined for each month, these amounts will be summed to determine Total Augmentation Resale Revenue (TARR) for the six-month period.

5.7.5.3.4 Calculating Net Augmentation Cost. Net Augmentation Cost (NAC) is the difference between TAUGC and TARR: NAC = TAUGC – TARR. When this calculation is performed before the six-month period, NAC represents the amount of additional revenues BPA expects to need in the upcoming six-month period. After the close of this six-month period, BPA will determine the actual amount of additional revenues required to meet actual augmentation costs for the six-month period.

5.7.5.3.5 Calculating Slice Revenues and Non-Slice Revenues from Loads Subject to the Load-Based Cost Recovery Adjustment Clause. These amounts represent the LB CRAC revenues from loads subject to the LB CRAC. Before a six-month period, BPA will calculate the revenues it expects to collect from the expected loads subject to the LB CRAC, at the base rates in the May Proposal. After the six-month period, BPA will calculate the amount of revenue it would receive using actual loads during the six-month period and rates from the May Proposal. All these revenue numbers are net of both the C&R Discount and the Low Density Discount (LDD).

Before the beginning of the six-month period, the values calculated for Slice Revenues from Loads Subject to LB CRAC (REVw/oLBC(S)) and Non-Slice Revenues from Loads Subject to the LB CRAC (REVw/oLBC(NS)) are used to determine the LB CRAC percent for the six-month period. Calculation of the LB CRAC percent must reflect BPA's best estimate of sales subject to the LB CRAC during the six-month period.

Recall that the LB CRAC percent is not recalculated after the close of the six-month period. At that point in time, BPA will determine what LB CRAC revenue over- or under-collection actually occurred during the six-month period. To make this determination, BPA must know what revenues actually were collected using the actual LB CRAC loads during the six-month period and the rates from the May Proposal. The values of REVw/oLBC(S) and REVw/oLBC(NS) are used in determining actual revenue over- or under-collection.

5.7.5.3.6 Calculating Total Revenues from Loads Subject to the Load-Based Cost Recovery Adjustment Clause. Total Revenues without Load-Based Cost Recovery Adjustment Clause (TREVw/oLBC) is the sum of REVw/oLBC(S) and REVw/oLBC(NS). Total Revenues with Load-Based Cost Recovery Adjustment Clause (TREVw/LBC) is the sum of REVw/LBC(S) and REVw/LBC(NS).

5.7.5.4 Calculating the Load-Based Cost Recovery Adjustment Clause Percent. This calculation is only performed before the beginning of the upcoming six-month period. It is not performed as a part of the after-the-fact calculations of a six-month period. The LB CRAC percent is determined by spreading the NAC across the total LB CRAC revenue received from all loads subject to the LB CRAC during the six-month period, where this revenue is determined using the rate from the May Proposal, and the forecasted loads for the six-month period (TREVw/oLBC). As a result, the LB CRAC percent represents the percent increase in revenues above the revenues BPA anticipates without the LB CRAC (or FB CRAC) that is expected to be required to meet NAC.

5.7.5.4.1 Calculating the Adjustment for Slice and Non-Slice Adjusted Rates [REVRATE(S) and REVRATE(NS)]. To determine the charge to be placed on Slice and non-Slice bills to recover augmentation costs, the NAC is first apportioned between Slice and non-Slice purchasers. Then, the resulting apportionment is converted into a charge.

The LB CRAC percent represents the percent change in revenues required to cover the expected value of NAC (*see* section 5.7.5.3.4). The increment in revenues required to cover NAC for Slice is the LB CRAC percent times the revenue expected from Slice purchasers for the upcoming six-month period, where revenue expected from Slice is calculated using expected sales for that upcoming period and the rate in the May Proposal. The revenue estimate used in this calculation excludes C&R Discount and LDD. The expected revenues from Slice sales at the Slice rate from the May Proposal is then added to this increment in revenue and the result is the forecasted amount of total revenue required from Slice to cover the Slice portion of the expected NAC for the upcoming six-month period. This amount is then divided by 6, then divided by 100, and the result is the new monthly Slice rate in dollars per 1 percent Slice.

The non-Slice calculation is similar. First, the LB CRAC percent is multiplied by the revenue expected from non-Slice purchasers for the upcoming six-month period calculated using expected sales for that upcoming period and the rates in the May Proposal. The revenue estimate used in this calculation excludes C&R Discount and any LDD. Next, the forecasted revenues from non-Slice sales, including C&R Discount and any LDD, are added to the increment in revenue from non-Slice sales. This sum is the forecast of the new amount of revenues required from non-Slice for the six-month period. This new revenue amount is then divided by the forecast of non-Slice revenues for the six-month period using forecasted loads and rates from the May Proposal but including C&R Discount and LDD. This ratio results in a percentage multiplier that is applied to the rates in the May Proposal. The product of this percentage multiplier to the rates in the May Proposal results in new rates to be applied to non-Slice loads subject to the LB CRAC in the upcoming six-month period.

5.7.5.4.2 Adjusting a Purchaser's Bill. For both Slice and non-Slice, the adjusted rates replace the rates from the May Proposal that would have otherwise appeared on the purchaser's bill for loads subject to the LB CRAC.

5.7.6 Calculating the Amount of Over- or Under-Recovery of Augmentation Costs through the Load-Based Cost Recovery Adjustment Clause. The calculation in this section is performed only once for each six-month period, after the end of the period, and the result is the amount of money that is to be either refunded to or collected from individual Slice and non-Slice purchasers. Determining the amount of over- or under-collection and adjusting the purchaser's bill is a four-step process. Each step is discussed below.

5.7.6.1 Calculating the Load-Based Cost Recovery Adjustment Clause revenues that were actually collected during the six-month period separately for Slice and Non-Slice. The result of this step is the actual amount of LB CRAC revenue collected from purchasers for the recently completed six-month period. This is done separately for Slice as a group and non-Slice as a group. For example, the actual amount of LB CRAC revenue received by BPA for Slice is the difference between the revenue received on loads during the six-month period with the LB CRAC applied, and the revenue that would have been received, using the actual loads subject to LB CRAC for the six-month period and the rates without the LB CRAC applied. For purposes of this calculation, the load amounts do not vary between the with-LB CRAC case and the without-LB CRAC case. Keeping the load amounts the same, BPA is able to identify the amount of revenue received from Slice purchasers that is attributable to the LB CRAC, referred to as Revenues Actually Received by BPA from the LB CRAC (Slice) (LBCREVREC(S)). This same procedure is performed for non-Slice to determine Revenues Actually Received by BPA from the LB CRAC (non-Slice) (LBCREVREC(NS)).

5.7.6.2 Calculating the Load-Based Cost Recovery Adjustment Clause revenues that are needed to cover the actual augmentation costs, divided between Slice and Non-Slice based on actual Load-Based Cost Recovery Adjustment Clause Revenues. It is likely that the amount of revenue actually collected from the LB CRAC (determined in the previous step) will not equal the amount of LB CRAC revenue that is required to cover actual NAC for the six-month period. Before this determination can be made, it is necessary to calculate how much LB CRAC revenue is required to cover the actual NAC for the most recently completed six-month period. This calculation will be performed separately for Slice and non-Slice purchasers of loads subject to the LB CRAC.

Since BPA will, by the time this step is reached, have determined the actual NAC as part of the calculations for the most recently completed six-month period, it is this value of NAC that is then apportioned between Slice and non-Slice purchasers. This step performs this apportionment.

To determine the amount of actual NAC to apportion to Slice, actual NAC is multiplied by the ratio of: (a) revenue received from Slice purchasers using actual loads for the six-month period and Slice rate with the LB CRAC applied divided by total revenue received from load subject to the LB CRAC from both Slice and non-Slice using actual loads for the six-month period; and (b) rates with the LB CRAC applied. The result of this calculation is referred to in the General Rate Schedule Provisions (GRSPs) as Actual LB CRAC Revenue Required (Slice) (ACTUALLBCREVREQ(S)). This same calculation is performed separately for non-Slice and the result is referred to as Actual LB CRAC Revenue Required (non-Slice) (ACTUALLBCREVREQ(NS)).

After these calculations are performed, one additional adjustment is made to the value of ACTUALLBCREVREQ(NS). This is the calculation referred to in section 5.7.5.3.4 where ,after the close of a six-month period, one NAC is determined using the 120-day rule and a separate NAC is determined using the five-day rule. The difference between these two calculations, referred to in the GRSPs as NACDIFF, is added to the value for ACTUALLBCREVREQ(NS). With the completion of these calculations, the amount of revenue actually required from Slice purchasers as a group and non-Slice purchasers as a group has been determined.

5.7.6.3 Calculating the difference between the actual Load-Based Cost Recovery Adjustment Clause revenue received and the actual Load-Based Cost Recovery Adjustment Clause revenue required to cover actual augmentation costs. In this step, the difference between the LB CRAC revenue actually collected and the LB CRAC revenue that is actually required to cover NAC for the six-month period just ended are compared. If the actual LB CRAC revenue collected exceeds what is required, purchasers of products subject to the LB CRAC will receive a refund. If the actual LB CRAC revenue collected is less than the revenue required, purchasers of products subject to the LB CRAC will face additional charges. This over- or under-collection of LB CRAC revenues will be apportioned to individual purchasers to determine the actual adjustment to each purchaser's bill.

5.7.6.4 Adjusting a Purchaser's Bill. There will be a separate line item on the bill for a refund or additional charges to cover actual augmentation costs. The same method is applied to both Slice and non-Slice when determining the amount of any refund or charge.

In section 5.7.6.3, the amount of any over- or under-recovery was apportioned between Slice purchasers as a group, and non-Slice purchasers as a group. These separate revenue over- or under-collection amounts for Slice and non-Slice must now be apportioned to individual purchasers of Slice and non-Slice. The "apportionment factor" that will be used is the ratio of the revenues actually collected from a specific Slice purchaser and the LB CRAC revenues received from all Slice purchasers. In this calculation, the revenues collected from a specific purchaser are determined using the purchaser's actual loads subject to the LB CRAC for the six-month period and the rates with the LB CRAC, and subtracting out any C&R Discount or LDD credits. The LB CRAC revenues received from all Slice purchasers are simply the sum of the revenues collected from individual purchasers, as defined in this section. This same calculation is also performed for each non-Slice purchaser.

Any over- or under-collection adjustments to an individual customer's bill will appear as a separate line item in the month following finalization of these calculations by BPA, which will occur on or about 90 days after the close of the six-month period for which these calculations are performed.

5.8 Slice Cost-Shift Analysis

An important design criterion of the Slice product is that the availability and purchase of Slice products must not shift costs or risks to non-Slice customers or to the Treasury. To ensure that BPA's Supplemental Proposal has not increased the costs or risks for other customers or for Treasury in light of the changed power market outlook, BPA compared several statistics for six pairs of cases in the Amended Proposal (*see* WP-02-E-BPA-61, at 4-1 to 4-8) and again in the initial Supplemental Proposal (*see* WP-02-E-BPA-69, at 5-17). The results demonstrated that offering the Slice product did not shift costs or risks to non-Slice Customers or to the Treasury, and therefore the Slice product design passed the Cost Shift Test. The test is not repeated here.

CHAPTER 6: INVESTOR-OWNED UTILITY RESIDENTIAL EXCHANGE PROGRAM SETTLEMENT

6.1 Introduction

The purpose of this chapter is to present BPA's changes to the May Proposal for calculating the financial aspect of the Investor-Owned Utility Residential Exchange Program Settlements (REP Settlement). Chapter 6.2 presents the background of BPA's May Proposal regarding the REP Settlement. Chapter 6.3 presents BPA's revisions to the May Proposal for the REP Settlement.

6.2 BPA's May Proposal for the Monetary Portion of Investor-Owned Utility Residential Exchange Program Settlements

BPA's Subscription Strategy proposed that REP Settlements with the Investor-Owned Utilities (IOUs) would be comprised of two types of benefits: power sales at the Residential Load (RL) or Priority Firm Power (PF) Exchange Subscription rate, and monetary benefits. Any monetary benefits would reflect the difference between the market price of power forecasted in BPA's rate case and the rate used to make such Subscription sales to the IOUs. BPA's May Proposal addressed the issue of the market forecast that would be used in calculating monetary benefits.

In the May Proposal, BPA developed price forecasts to be used in: (1) designing rates; (2) determining surplus revenue; (3) calculating the cash component of the proposed settlement of the REP with regional IOUs; (4) estimating the cost of augmenting the Federal Base System (FBS) with five-year flat block purchases; and (5) developing BPA's Cost Recovery Adjustment Clause (CRAC) analyses. For designing rates, BPA relied on the Marginal Cost Analysis (MCA), which uses the AURORA model. The MCA is described in detail in the testimony of Anderson, *et al*., WP-02-E-BPA-16. The testimony of Keep, *et al*., WP-02-E-BPA-17, describes how the MCA is used in rate design. For determining surplus revenue, BPA used a forecast of prices based on the MCA but with adjustments. Oliver, *et al*., WP-02-E-BPA-20, at 2. This forecast is described in greater detail in the testimony of Conger, *et al.*, WP-02-E-BPA-15. BPA developed a five-year flat block price forecast for calculating the cash component of the proposed settlement of the REP and for estimating the cost of augmenting the FBS with five-year flat block purchases. Oliver, *et al*., WP-02-E-BPA-20, at 2.

As noted above, BPA developed a five-year flat block price forecast for two purposes. *Id*. The first purpose was for use in calculating the cash component of the proposed settlement of the REP with regional IOUs as described in BPA's Power Subscription Strategy. *Id*. The Power Subscription Strategy, at 8-9, states:

> BPA's strategy is that IOUs may agree to a settlement of the Residential Exchange Program in which they would be able to purchase a specified amount of power under subscription for their residential and small farm consumers at a rate approximately equivalent to the PF Preference rate. . .
>
> In Subscription, BPA proposes a settlement in which residential and small farm loads of the IOUs will be assured access to the equivalent of 1,800 aMW of Federal power for the 2002–2006 period. Of this amount, at least 1,000 aMW will be met with actual BPA power deliveries. The remainder may be provided through either a financial arrangement or additional power deliveries, depending on which approach is most cost-effective for BPA.
>
> . . . Any cash payment will reflect the difference between the market price of power forecast in the rate case and the rate used to make such Subscription sales. The actual power deliveries for these loads will be in equal hourly amounts over the period . . .

Id. at 2-3. The other forecasts developed in BPA's May Proposal were not appropriate for estimating advance purchases of five-year flat block energy. *Id*. at 3. Therefore, a separate forecast was developed for this purpose. *Id*.

The second purpose for this forecast was to estimate the purchase price for power for five-year flat blocks of energy to meet BPA's firm obligations. *Id*. BPA's firm obligations and firm resources are described in the Loads and Resources Study, WP-02-FS-BPA-01. Some of BPA's firm obligations are met by making purchases during the rate period on an as-needed basis, depending on generation levels, hydro conditions, and weather conditions. Oliver, *et al*., WP-02-E-BPA-20, at 3. In addition, BPA anticipated making substantial purchases prior to the rate period for terms longer than one year to augment the FBS. *Id*. A forecast of the five-year price of the flat block power acquired in the 1999-2000 market timeframe was considered a more accurate reflection of the costs and structure of these augmentation purchases than the other price estimates (*e.g*., AURORA price forecast). *Id*.

BPA used a combination of qualitative and quantitative assessments as well as professional judgment to arrive at a price estimate of five-year flat block purchases. *Id*. BPA used actual market experience to derive a price estimate of five-year flat block purchases and confirmed this estimate by using a derivation of BPA's MCA, market quotes for forward transactions in the five-year period, and a reasonable extrapolation of current market prices. *Id*.

6.3 Supplemental Proposal for Market Price Forecast for Investor-Owned Utility Residential Exchange Program Settlements

BPA proposes to amend its May Proposal to reflect more current estimates of BPA's load obligations as well as its expectation of higher power market prices. The higher estimate of BPA's load obligations has increased BPA's forecasted amount of system augmentation purchases. BPA also believes that these greater amounts of power purchases are likely to be made at a higher average price than was initially estimated in BPA's May Proposal. These facts caused BPA to review the appropriateness of its rate case market price forecast for use in the calculation of the monetary benefits of the REP Settlement, and caused BPA to review whether BPA's Subscription policy goals were still being satisfied. In BPA's Amended Proposal, BPA proposed a $34.1/megawatthour (MWh) forecast. BPA now proposes to use a $38/MWh market price forecast for the Fiscal Year (FY) 2002-2006 rate period as its five-year forward flat block price forecast.

The Subscription Strategy states that BPA would use a rate case market price forecast as one of the elements in the calculation of monetary benefits for the REP Settlement. A fixed price forecast was used to limit BPA's risk and to establish a known benefit amount. In BPA's May Proposal, BPA previously identified a market price forecast that averaged $28.1/MWh for FY 2002 to 2006. While not used in BPA's May Proposal for the determination of monetary benefits, BPA also developed other market price forecasts in its May Proposal. One such forecast is the risk-adjusted average market price forecast. The risk-adjusted average market price forecast is the average spot market price for all hours of the year estimated by AURORA to quantify BPA's operating risk in RiskMod for the Risk Analysis Study. This forecast is $34.1/MWh. In BPA's Amended Proposal, BPA proposed using of this forecast for the calculation of the financial benefits in the IOUs' REP Settlements. Upon further review, however, BPA now proposes to adjust its $34.1/MWh five-year flat block forecast to $38/MWh. There is currently a broad range of market forecasts in a volatile and changing market and $38/MWh, which is reflected in the Partial Stipulation and Settlement Agreement, represents a reasonable forecast to be used in the determination of financial benefits under the REP settlements. BPA believes, given the total settlement package, that this $38/MWh price forecast is more appropriate for use as the five-year flat block price forecast than the $28.1/MWh forecast or the $34.1/MWh forecast.

Use of the $38/MWh market price forecast recognizes that BPA faces increased amounts of augmentation purchases and will not make all of the purchases prior to the start of the five-year rate period. BPA proposes that the RL and PF Exchange Subscription rates, only when used for the calculation of monetary benefits under the REP Settlements, should be exempt from the

Load-Based (LB) and Financial-Based (FB) CRACs. BPA chose to protect the monetary benefits from current price volatility by exempting the RL and PF Exchange Subscription rates from the proposed LB and FB CRACs.