BP-18 Rate Proceeding

Initial Proposal

Power and Transmission Risk Study

BP-18-E-BPA-05

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COMMONLY USED ACRONYMS AND SHORT FORMS

ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DD	Dividend Distribution
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EE	Energy Efficiency
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
ESA	Endangered Species Act
ESS	Energy Shaping Service
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System

FELCC	firm energy load carrying capability
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GMS	Grandfathered Generation Management Service
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IM	Montana Intertie
inc	increase, increment, or incremental
IOU	investor owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review
IR	Integration of Resources
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IS	Southern Intertie
kcfs	thousand cubic feet per second
kW	kilowatt
kWh	kilowatthour
LDD	Low Density Discount
LLH	Light Load Hour(s)
LPP	Large Project Program
LPTAC	Large Project Targeted Adjustment Charge
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries

NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
Peak	Peak Reliability (assessment/charge)
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POR	Point of Receipt
Project Act	Bonneville Project Act
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point to Point
PUD	public or people's utility district
PW	WECC and Peak Service
RAM	Rate Analysis Model (computer model)
RCD	Regional Cooperation Debt
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
RDC	Reserves Distribution Clause
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark

ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
SCD	Scheduling, System Control, and Dispatch rate
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TGT	Townsend-Garrison Transmission
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish & Wildlife Service
VERBS	Variable Energy Resources Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

1. INTRODUCTION

The Bonneville Power Administration's (BPA) business environment is replete with uncertainty that a rigorous ratesetting process must consider. The objectives of the Power and Transmission Risk Study are to identify, model, and analyze the impacts that key risks and risk mitigation tools have on BPA's net revenue (total revenue less total expenses) and cash flow. The Risk Study ensures that power and transmission rates are set high enough that the probability BPA can meet its cash obligations is at least as high as required by BPA's Treasury Payment Probability (TPP) standard. This evaluation is carried out in two distinct steps: a risk assessment step, in which the distributions, or profiles, of operating and non-operating risks are defined, and a risk mitigation step, in which risk mitigation tools are assessed with respect to their ability to recover costs given these uncertainties. The risk assessment estimates both the central tendency of risks and the potential variability of those risks. Both of these elements are used in the ratemaking process.

In this Study the words "risk" and "uncertainty" are used in similar ways. Generally, each can have both up-side and down-side possibilities, that is, both beneficial and harmful impacts on BPA objectives. The BPA objectives that may be affected by the risks considered in this Study are generally BPA's financial objectives.

1.1 Purpose of the Power and Transmission Risk Study

The Power and Transmission Risk Study demonstrates that BPA's proposed rates and risk mitigation tools together meet BPA's standard for financial risk tolerance, the TPP standard. This Study includes quantitative and qualitative analyses of risks to net revenue and tools for mitigating those risks. It also establishes the adequacy of those tools for meeting BPA's TPP standard.

In addition to mitigating the risks that reserves and other liquidity are insufficient to repay the Treasury, this Study also addresses the risk that reserves are insufficient to maintain BPA's credit rating. Maintaining a high credit rating is important to BPA's operations and access to capital. To maintain BPA's credit rating and mitigate the risk of BPA's credit rating being downgraded, the Risk Study implements the terms of BPA's Financial Reserves Policy, which is designed to provide stability and transparency to the accumulation and use of financial reserves. As described more fully in Chapter 6, the Financial Reserves Policy establishes a target level for financial reserves for each business line and for BPA as an agency, and establishes lower and upper thresholds for reserves.

2. FINANCIAL RISK POLICIES AND OBJECTIVES

2.1 Risk Mitigation Policy Objectives

The following policy objectives guide the development of the risk mitigation package:

- Create a rate design and risk mitigation package that meets BPA financial standards, particularly achieving a 95 percent two-year Treasury Payment Probability.
- Produce the lowest possible rates, consistent with sound business principles and statutory obligations, including BPA's long-term responsibility to invest in and maintain the Federal Columbia River Power System (FCRPS) and Federal Columbia River Transmission System (FCRTS).
- Maintain sufficient financial reserves levels to support BPA's credit rating.
- Include in the risk mitigation package only those elements that can be relied upon.
- Do not let financial reserve levels build up to unnecessarily high levels.
- Allocate costs and risks of products to the rates for those products to the fullest extent possible; in particular, for Power rates, prevent any risks arising from Tier 2 service from imposing costs on Tier 1 or requiring stronger Tier 1 risk mitigation.
- Rely prudently on liquidity tools, and create means to replenish them when they are used in order to maintain long-term availability.

These objectives are not completely independent and may sometimes conflict with each other. Thus, BPA must create a balance among these objectives when developing its overall risk mitigation strategy.

2.2 How Risk Results Are Used

The main result from the risk assessment and mitigation process is the TPP calculation. If this number is 95 percent or higher, then the rates and risk mitigation tools meet BPA's TPP standard. The calculations also take into account the thresholds and caps for the Cost Recovery Adjustment Clause (CRAC) and the Reserves Distribution Clause (RDC). These values are incorporated in the Power and Transmission General Rate Schedule Provisions (GRSPs) and will be applied in later calculations outside the ratesetting process for determining whether a CRAC or RDC will be applied to certain power and transmission rates for FY 2018 or FY 2019.

2.3 BPA's Treasury Payment Probability Standard

In the WP-93 rate proceeding, BPA adopted and implemented its 10-Year Financial Plan, which included a policy requiring that BPA set rates to achieve a high probability of meeting its payment obligations to the U.S. Treasury (Treasury). *See* 1993 Final Rate Proposal Administrator's Record of Decision (ROD), WP-93-A-02, at 72. The specific standard set in the 10-Year Financial Plan was a 95 percent probability of making both of the annual Treasury payments in the two-year rate period on time and in full. This TPP standard was established as a rate period standard; that is, it focuses upon the probability that BPA can successfully make all of its payments to Treasury over the multi-year rate period rather than the probability for a single year. The 10-Year Financial Plan was updated July 31, 2008, and renamed the "Financial Plan." *See* http://www.bpa.gov/Finance/FinancialInformation/FinancialPlan/Pages/default.aspx.

The Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act) states that BPA's payments to Treasury are the lowest priority for revenue application, meaning that payments to Treasury are the first to be missed if financial reserves are insufficient to pay all bills on time. 16 U.S.C. § 839e(a)(2)(A). Therefore, TPP is a prospective measure of BPA's overall ability to meet its financial obligations.

BPA's Treasury payments are an obligation of the agency. Since 2002, TPP has been independently measured for the Power Services (PS) and Transmission Services (TS) business lines. This Study tests the ability of PS and TS to make their portions of the Treasury payments over the rate period.

The following items (explained in more detail in Chapter 4 below) are included in the calculation of TPP:

- *Starting Reserves (Starting Financial Reserves Available for Risk Attributed to PS or TS).* Financial reserves comprise (1) cash and investment instruments held in the BPA Fund and (2) the deferred borrowing balance. Financial reserves available for risk do not include funds held for others. For example, amounts in the BPA Fund that were provided by customers as collateral for creditworthiness are excluded. Deferred borrowing amounts exist when planned borrowing has not yet been completed. When the borrowing is completed, cash in the BPA Fund is increased and the deferred borrowing balance is reduced by the same amount, leaving financial reserves unchanged.
- *Planned Net Revenues for Risk (PNRR).* PNRR is the final component of the revenue requirement that may be added to annual expenses. PNRR is needed only when the risk mitigation provided by starting financial reserves and other risk mitigation tools is insufficient to meet the TPP standard.
- *BPA's Treasury Facility.* The Treasury Facility is an arrangement BPA has with the U.S. Treasury that allows BPA to borrow up to $750 million on a short-term basis. For ratemaking purposes, this facility is allocated in each rate case so as to provide the greatest quantitative benefit to BPA rates. The full $750 million in the Treasury Facility is considered to be available for the liquidity needs associated with PS; reserves for risk attributed to TS are sufficient for the liquidity needed to mitigate TS financial risk. The Treasury Facility functions similarly to additional financial reserves.
- *Within-year Liquidity Need.* The within-year liquidity need is an amount of cash or short-term borrowing capability that must be set aside for meeting within-year liquidity

needs (or risks). In the BP-18 rate period, the within-year liquidity need is $320 million for PS and $100 million for TS. The methodologies for calculating these amounts and the resulting amounts remain unchanged from BP-16 rates.

- *Liquidity Reserves Level.* The liquidity reserves level is the amount of financial reserves that is allocated for meeting the within-year liquidity need. For this Study, the liquidity reserves level is $0 for PS and $100 million for TS.
- *Liquidity Borrowing Level.* The liquidity borrowing level is the amount of the Treasury Facility set aside to meet the within-year liquidity need. For this Study, the liquidity borrowing level is $320 million for PS. This leaves $430 million of the $750 million Treasury Facility available for year-to-year liquidity needs for PS (*i.e.*, TPP needs). Within-year liquidity needs for TS are handled through the liquidity allocation of liquidity reserves; the TS liquidity borrowing level is $0.
- *Cost Recovery Adjustment Clause.* The CRAC is an upward adjustment to applicable power and transmission rates. The adjustment is applied to rates charged for service beginning in October following a fiscal year in which PS or TS Accumulated Calibrated Net Revenue (ACNR) falls below the Power or Transmission CRAC threshold. The Power CRAC threshold will be updated in July 2017, as specified in the Financial Reserves Policy, Power GRSP II.O, and Transmission GRSP II.H. For the Initial Proposal, the PS threshold is set at the ACNR equivalent of $0 in PS financial reserves available for risk, which is the minimum allowed by the Financial Reserves Policy. The TS threshold is set at the ACNR equivalent of $99 million in TS financial reserves available for risk; this equals the Transmission lower financial reserves threshold in the Financial Reserves Policy.
- *Reserves Distribution Clause.* The RDC allows the Administrator to put reserves for risk that are above the level necessary for TPP and credit support to higher-value purposes, such as retirement of debt, incremental capital investment, or a dividend distribution

(DD). A DD is a downward adjustment to the applicable power or transmission rates. The adjustment is applied to rates charged for service beginning in October following a fiscal year in which ACNR is above the RDC threshold. A reserves distribution may be made if (1) reserves for risk attributed to a business line exceed the RDC threshold for that business line and (2) BPA reserves for risk exceed the BPA RDC threshold. *See* Power GRSP II.P and Transmission GRSP II.I.

2.4 Quantitative versus Qualitative Risk Assessment and Mitigation

This study distinguishes between quantitative and qualitative perspectives of risk. The quantitative risk assessment is a set of risk simulations that are modeled using a Monte Carlo approach, a statistical technique in which deterministic analysis is performed on a distribution of inputs, resulting in a distribution of outputs suitable for analysis. The output from the quantitative risk assessment is a set of 3,200 possible financial results (net revenues) for each of the two years in the rate period (FY 2018–2019) and for the year preceding the rate period (FY 2017). The models used in the quantitative risk assessment are described in Chapter 3. Quantitative risk modeling for Power is described in section 4.1 and for Transmission in section 5.1.

BPA's primary tool for risk mitigation is financial reserves. BPA also uses the Power CRAC and Transmission CRAC to manage financial risk. The CRACs add additional risk mitigation to that provided by financial reserves and liquidity. When financial reserves available for risk plus the additional revenue earned through the CRAC do not provide sufficient risk mitigation to meet the 95 percent TPP standard, PNRR is added to the revenue requirement. This increases rates, which generates additional reserves, which increases TPP. The models used in the quantitative risk mitigation are described in Chapter 3. Modeling of quantitative risk mitigation is described in sections 4.2 for Power and 5.2 for Transmission.

Some financial risks are unsuitable for quantitative modeling but are significant enough that they need to be accounted for. These risks usually fit into one of two general categories that make them unsuitable for modeling. The first type is risks for which there is no basis for estimating the probabilities of future outcomes: relevant historical data is unavailable and subject matter experts are unable to provide estimates of probabilities. The second type is risks for which modeling may adversely influence the future actions of human beings, including possible impact on legal proceedings.

For the most part, the qualitative risk assessment is a logical assessment of possible events that could have significant financial consequences for BPA. The qualitative risk mitigation describes measures BPA has put in place, or responses BPA would make to these events, and then presents logical analyses of whether any significant residual financial risk remains for BPA after taking into account the mitigation measures. Qualitative Power risks and associated mitigation are described in section 4.3. There have been no qualitative risks identified for Transmission rates.

2.5 BPA's Financial Reserves Policy

The Financial Reserves Policy is intended to provide a consistent, transparent, and financially prudent method for determining target financial reserves levels and upper and lower financial reserves thresholds for Power Services, Transmission Services, and BPA as a whole. The policy also describes the actions BPA may take in response to financial reserves levels that either fall below a lower threshold or exceed an upper threshold. The main components of the Financial Reserves Policy and its proposed implementation for the BP-18 rate period are described in Chapter 6. The Financial Reserves Policy is attached to the testimony of Harris *et al.*, BP-18-E-BPA-17.

3. TOOLS AND SIMULATORS USED IN QUANTITATIVE RISK MODELING

This chapter provides an overview of BPA's general approach to quantitative risk assessment and mitigation. More detailed descriptions of how this approach is implemented for Power and Transmission rates are provided below in Chapters 4 and 5.

The approach BPA takes to quantify risks and assess whether BPA's proposed risk mitigation packages for PS and TS rates are sufficient is based on Monte Carlo simulation. In this technique, risks and the relationships between risks are defined using probabilistic models. A large number of games, or iterations, are run. In each game, a random value is drawn for each probabilistic model and the results are recorded. The entire set of gamed results is examined to verify that BPA's risk mitigation objectives have been achieved.

The 3,200 games from the quantitative risk assessment are used in the quantitative risk mitigation step to determine if BPA's financial risk standard, the 95 percent TPP standard, has been met. *See* §§ 2.3 and 3.1.5.

3.1 Modeling Process to Calculate TPP

3.1.1 Study Models

BPA traditionally models risks using Monte Carlo simulation. Accordingly, models including AURORAxmp®, the Revenue Simulation Model (RevSim), the Non-Operating Risk Models (P-NORM and T-NORM), and ToolKit each run 3,200 iterations, or games. AURORAxmp® estimates electricity prices, which serve as inputs to numerous other studies, including the Power portions of this Study. RevSim (*see* § 3.1.2.1 below) combines deterministic load, resource, revenue, and expense values with the uncertainty in spot market electricity prices, loads and resources, PS transmission and ancillary services expenses, and Northwest Power Act section 4(h)(10)(C) credits to produce 3,200 values for PS annual net revenue for each year of the BP-18 rate period, FY 2018 and FY 2019. The output of this process is combined with the distribution of output from P-NORM and provided to the ToolKit to calculate PS TPP. Similarly, TS revenue uncertainty is modeled for the TS Sales and Revenue Forecasts. *See* Transmission Rates Study and Documentation, BP-18-E-BPA-08, § 2. The Transmission revenue uncertainty is combined with the distribution of output from T-NORM and provided to ToolKit to calculate TS TPP.

3.1.2 Revenue Simulation Models

3.1.2.1 Power—RevSim

RevSim calculates secondary energy revenues, firm surplus energy revenues, balancing power purchase expenses, and system augmentation purchase expenses. Two financial operating risks are modeled externally and input to RevSim: 4(h)(10)(C) credits and PS transmission and ancillary services expenses. The results from RevSim and these two financial operating risks are provided for input into the Rate Analysis Model (RAM2018). RevSim also simulates PS operating net revenue for use in ToolKit. Inputs to RevSim include the output of certain risk models discussed in the Power Market Price Study (to the extent that they affect generation and loads) and prices from AURORAxmp®. *See* Power Market Price Study and Documentation, BP-18-E-BPA-04, § 2.3. RevSim also uses deterministic monthly load and resource data; revenues, expenses, and rates from RAM2018; and non-varying revenues and expenses from the Power Revenue Requirement Study, BP-18-E-BPA-02, and Chapter 2 of the Power Rates Study, BP-18-E-BPA-01.

3.1.2.1.1 Operating Risk Models

Uncertainty in each of the following variables is modeled as independent:

- WECC Loads

- Natural Gas Price
- Regional Hydroelectric Generation
- Pacific Northwest (PNW) Hourly Wind Generation
- CGS Generation
- PNW Hourly Intertie Availability

Each model uses historical data to calibrate a statistical model. The model can then, by Monte Carlo simulation, generate a distribution of outcomes. Each realization from the joint distribution of these models constitutes one game and serves as input to AURORAxmp®. Where applicable, the results for that game also serve as input to RevSim. The prices from AURORAxmp®, combined with the deterministic and variable values used in RevSim, constitute one net revenue game. Each risk model may not generate 3,200 games, and where necessary a bootstrap approach is used to produce a full distribution of 3,200 games. Each of the 3,200 draws from the joint distribution is identified uniquely, which guarantees coordination between AURORAxmp® prices and RevSim inventory levels.

Expenses associated with the purchase of system augmentation are estimated in RevSim using variable electricity prices calculated under 1937 "critical water" conditions. These results are used by RAM2018 when calculating rates and calculating net revenues provided for input into the ToolKit model. *See* § 3.1.5.

Revenues associated with the firm surplus energy sales are estimated in RevSim using variable electricity prices calculated under 80 water year conditions. These results are used by RAM2018 when calculating rates and calculating net revenues provided for input into the ToolKit model.

The monthly flat electricity prices calculated by AURORAxmp® under 80 water year conditions for all 3,200 games for each fiscal year are inputs into the 4(h)(10)(C) Credits Risk Model, which calculates the average 4(h)(10)(C) credits included in the Power Revenue Requirement Study, BP-18-E-BPA-02. The 4(h)(10)(C) credits calculated by the 4(h)(10)(C) Credits Risk Model for 3,200 games for each fiscal year are input into RevSim for use in calculating net revenue risk.

The monthly flat secondary energy values calculated by RevSim for all 3,200 games for each fiscal year are inputs into the PS Transmission and Ancillary Services Expense Risk Model, which calculates the average PS transmission and ancillary services expenses included in the Power Revenue Requirement Study, BP-18-E-BPA-02. The transmission and ancillary services expenses calculated by the PS Transmission and Ancillary Services Expense Risk Model for 3,200 games for each fiscal year are input into RevSim for use in calculating net revenue risk.

3.1.2.2 Transmission—RevRAM

Transmission revenue is a key input to the income statement and to T-NORM. The Transmission Revenue Risk Assessment Model (RevRAM) models the revenue uncertainty in BPA's transmission products and services. RevRAM uses Microsoft Excel®-based models and @Risk® to generate 3,200 iterations with Monte Carlo simulation. Transmission products and services that are modeled for revenue uncertainty include:

- Network Load Service (NT), which has risk based on load variability.
- Long-Term Point-to-Point (PTP) Service on the Network and Southern Intertie (PTP LT and IS LT), which has risk based on probability of customers taking the contractual service.
- Short-Term Service on the Network and Intertie (PTP ST and IS ST), which has risk based on variability of market conditions that include hydro and prices.

- Legacy Products (Formula Power Transmission (FPT) and Integration of Resources (IR)), which are not modeled for risk as their conversion probability is accounted for in PTP LT.
- Scheduling, System Control and Dispatch (SCD), which has variability dependent on sales of Network and Intertie transmission service.
- Other revenues, including Delivery, Fiber and PCS Wireless, and other miscellaneous revenues, which have differing inputs but are modeled using historical variability.
- Generation Inputs risk is modeled for products that have variability in revenues but a fixed expense payment to BPA Power Services (Regulation and Frequency Response (RFR), Variable Energy Resource Balancing Service (VERBS), and Dispatchable Energy Resource Balancing Service (DERBS)). Products with offsetting revenue and expense are not modeled for risk (Energy Imbalance/Generation Imbalance (EI/GI), and Operating Reserve (OR)).

These transmission products and services are modeled individually in Microsoft Excel®. A separate spreadsheet tab in RevRAM adds all individual revenue products to generate the total transmission revenue forecast (excludes reimbursable revenues).

3.1.3 Expense Variability Simulator

NORM is an analytical risk tool that quantifies the impacts of non-operating risks in the ratesetting process. NORM follows BPA's traditional approach to modeling risks, which uses Monte Carlo simulation. In this technique, a model runs through a number of games or iterations. In each game, each modeled uncertainty is randomly assigned a value from its probability distribution based on input specifications for that uncertainty. After all of the games are run, the results can be analyzed and summarized or passed to other tools.

New risks for inclusion in NORM are identified based on review of historical results and querying of subject matter experts. If a financial risk has a significant range of financial uncertainty and is suitable for quantitative modeling, it is included in the model. If a risk has a significant range of financial uncertainty but is not suitable for modeling, it is evaluated in the qualitative risk analysis. *See* § 4.3.

To obtain the data used to develop the probability distributions used by NORM, subject matter experts were interviewed for each capital and expense item modeled. The subject matter experts were asked to assess the risks concerning their cost estimates, including the possible range of outcomes and the associated probabilities of occurrence. In some instances, the subject matter experts provided a complete probability distribution.

After data is gathered, risks are modeled using Excel® and @RISK®. Risks are generally modeled using continuous or discrete probability distributions selected to best match the available data on the risk. Serial correlation (correlation over time) and correlation between different risks are included in the modeling when relevant and assessable.

3.1.3.1 Power—P-NORM

P-NORM models PS risks that are not incorporated into RevSim, such as risks around corporate costs covered by power rates and debt service-related risks. P-NORM also models some changes in revenue and some changes in cash flow. While the operating risk models and RevSim are used to quantify operating risks, such as variability in economic conditions, load, and generating resource capability, P-NORM is used to model risks surrounding projections of non-operations-related revenue or expense levels in the PS revenue requirement. P-NORM models the accrual impacts of the included risks, as well as Net Revenue-to-Cash (NRTC) adjustments, which translate the net revenue impacts into cash flow impacts. P-NORM supplies 3,200 games (or iterations) of net revenue and cash flow impacts of the risks that it models. The outputs from P-NORM, along with the outputs from RevSim, are passed to the ToolKit model to assess Power TPP.

3.1.3.2 Transmission—T-NORM

Similar to P-NORM, T-NORM models TS risks that are not incorporated into RevRam, as well as some changes in revenue and some changes in cash flow. T-NORM models the accrual impacts of the included risks, as well as NRTC adjustments, which translate the net revenue impacts into cash flow impacts. T-NORM supplies 3,200 games (or iterations) of net revenue and cash flow impacts of the risks that it models. The outputs from T-NORM, along with the outputs from RevRam, are passed to the ToolKit model to assess TS TPP.

3.1.4 Net Revenue-to-Cash Adjustments

One of the inputs to the ToolKit (through NORM) is the NRTC Adjustment. Most of BPA's probabilistic modeling is based on impacts of various factors on net revenue. BPA's TPP standard is a measure of the probability of having enough cash to make payments to the Treasury. While cash flow and net revenue generally track each other closely, there can be significant differences in any year. For instance, the requirement to repay Federal borrowing over time is reflected in the accrual arena as depreciation of assets. Depreciation is an expense that reduces net revenue, but there is no cash inflow or outflow associated with depreciation. The same repayment requirement is reflected in the cash arena as cash payments to the Treasury to reduce the principal balance on Federal bonds and appropriations. These cash payments are not reflected on income statements. Therefore, in translating a net revenue result to a cash flow result, the impact of depreciation must be removed and the impact of cash principal payments must be added. P-NORM and T-NORM calculate 3,200 NRTC adjustments to make the necessary changes to convert accrual results (net revenue results) into the equivalent cash flows so the ToolKit can calculate reserves values in each game and thus calculate TPP.

The NRTC Adjustment is modeled probabilistically in NORM using a table of adjustments as its starting point and includes 3,200 gamed adjustments based on deviations in revenue and expense items. *See* §§ 4.1.3 and 5.1.3.

3.1.4.1 @RISK$^{®}$ Computer Software

P-NORM and T-NORM are maintained in Microsoft Excel$^{®}$ with the add-in risk simulation computer package @RISK$^{®}$, a product of Palisade Corporation, Ithaca, NY. @RISK$^{®}$ allows analysts to develop models incorporating uncertainty in a spreadsheet environment. Uncertainty is incorporated by specifying the probability distribution that reflects the specific risk, providing the necessary parameters that describe the probability distribution, and letting @RISK$^{®}$ sample values from the probability distributions based on the parameters provided. The values sampled from the probability distributions reflect their relative likelihood of occurrence. The parameters required for appropriately quantifying risk are not developed in @RISK$^{®}$ but in analyses external to @RISK$^{®}$.

3.1.5 Overview of the ToolKit

The ToolKit is a model that is used to evaluate the ability of PS to meet BPA's TPP standard given the net revenue variability embodied in the distributions of operating and non-operating risks. The ToolKit is modeled in the programming language R and uses a Web-based interface for users to interact with the model.

The ToolKit contains several parameters *(e.g.,* Starting Reserves and CRAC and RDC settings) defined within the ToolKit file itself. The ToolKit reads in data from two external files. For

Power, ToolKit reads in a file from RevSim and a file from P-NORM. For Transmission, ToolKit reads in a file from RevRam and a file from T-NORM. Most of the modeling of risks is performed by the input risk models, as described in Chapters 4 and 5.

The ToolKit is used to assess the effects of various policies, assumptions, changes in data, and risk mitigation measures on the level of year-end reserves and liquidity attributable to Power Services, and thus on TPP. It registers a deferral of a Treasury payment when reserves and all sources of liquidity are exhausted in any given year. The ToolKit is run for 3,200 games (or iterations). TPP is calculated by dividing the number of games where a deferral did not occur in either year of the rate period by 3,200. The ToolKit calculates the TPP and other risk statistics and reports results. The ToolKit also allows analysts to calculate how much PNRR is needed in rates, if any, to meet the TPP standard.

If TPP is below the 95 percent standard required by BPA's Financial Plan, then one of several risk mitigation tools may be adjusted in the ToolKit until the standard is met. These options include (1) raising the CRAC threshold, which makes it more likely that the CRAC will trigger; (2) increasing the cap on the annual revenue the CRAC can collect; and/or (3) adding PNRR to the revenue requirement.

3.1.5.1 R Statistical Software

ToolKit was developed in R (www.r-project.org). R is an open-source statistical software environment that compiles on several platforms. It is released under the GNU GPL (GNU General Public License) and is free software. R supports the development of risk models through an object-oriented, functional scripting environment; that is, it provides an interface for managing proprietary risk models and has a native random number generator useful for sampling distributions from any kernel.

4. POWER RISK

4.1 Power Quantitative Risk Assessment

This chapter describes the uncertainties pertaining to Power Services finances in the context of setting power rates. Section 4.2 describes how BPA determines whether its risk mitigation measures are sufficient to meet the TPP standard given the risks detailed in this chapter.

Variability in PS net revenue, largely a product of uncertainty in both Federal hydro generation and market prices, is substantial. BPA also considers uncertainty in (1) customer load; (2) Columbia Generating Station (CGS) output; (3) wind generation; (4) system augmentation costs; (5) PS transmission and ancillary services expenses; and (6) Northwest Power Act section 4(h)(10)(C) credits. The effects of these risk factors on PS net revenue are quantified in this Study.

PS also faces risks not directly related to the operation of the power system. These non-operating risks are modeled in the Power Non-Operating Risk Model (P-NORM). These risks include the potential for CGS, Corps of Engineers (USACE), and U.S. Bureau of Reclamation (USBR) operations and maintenance (O&M) spending to differ from their forecasts. P-NORM also accounts for variability in interest rate expense. P-NORM models variability in net revenues, including uncertainty in the length of the CGS refueling outages in FY 2017 and FY 2019.

4.1.1 RevSim

As described in section 3.1.2, RevSim calculates secondary energy revenues, firm surplus energy revenues, balancing power purchase expenses, and system augmentation purchase expenses. Two financial operating risks are modeled externally and input into RevSim: 4(h)(10)(C) credits and PS transmission and ancillary services expenses. The results from RevSim and these two financial operating risks are provided for input into the Rate Analysis Model (RAM2018). RevSim also determines, by simulation, PS operating net revenue risk for use in the ToolKit Model. *See* § 3.1.5 above.

4.1.1.1 Inputs to RevSim

Inputs to RevSim include risk data simulated by various risk models and market prices calculated by AURORAxmp®. *See* Power Market Price Study, BP-18-E-BPA-04, section 2.1, regarding AURORAxmp®. Other inputs include deterministic monthly data from other rate development studies.

4.1.1.1.1 Deterministic Data

Deterministic data are data provided as single forecast values, as opposed to data presented as a distribution of many values.

4.1.1.1.2 Loads and Resources

Monthly HLH and LLH load and resource data are provided by the Power Loads and Resources Study, BP-18-E-BPA-03. A summary of these load and resource data in the form of monthly energy for FY 2018–2019 is provided in the Power Loads and Resources Study Documentation, BP-18-E-BPA-03A, section 9.1.

4.1.1.1.3 Miscellaneous Revenues

Miscellaneous revenues represent estimated revenues that are not subject to change through BPA's ratesetting process. *See* Power Rates Study, BP-18-E-BPA-01, section 9.2, for a discussion of miscellaneous revenues.

4.1.1.1.4 Composite, Non-Slice, Load Shaping, and Demand Revenues

Composite, Non-Slice, Load Shaping, and Demand revenues are provided by RAM2018. Consistent with the Tiered Rate Methodology (TRM), Composite and Non-Slice revenues do not vary in the RevSim revenue simulation, but Load Shaping and Demand revenues do vary. The Load Shaping billing determinants and Load Shaping rates from RAM2018 are input into RevSim to facilitate the calculation of changes in Load Shaping revenue. Demand billing determinants and rates from RAM2018 are input into RevSim to facilitate the calculation of changes in Demand revenue. *See* Power Rates Study Documentation, BP-18-E-BPA-01A, Table 3.1.5.

4.1.1.1.5 Risk Data

Uncertainty around the deterministic data provided to RevSim must be considered in the determination of TPP in ToolKit. Specifically, the uncertainty considered in RevSim is called operational uncertainty, as opposed to the non-operational uncertainty considered in P-NORM. Uncertainty in the deterministic data is represented by risk data; *i.e.,* a distribution of many values.

Input data to RevSim for operational uncertainty include Federal hydro generation risk, PS load risk, CGS generation risk, PS wind generation risk, PS transmission and ancillary services expense risk, 4(h)(10)(C) credit risk, and electricity price risk. The load, resource, and price risk inputs are reflected in the risk distributions for secondary energy revenues, firm surplus energy revenues, balancing power purchases expenses, and system augmentation expenses. These risks, along with the 4(h)(10)(C) credit risk and PS transmission and ancillary services expense risk, are reflected in the PS operating net revenues calculated by RevSim and provided for input into ToolKit.

4.1.1.1.5.1. Federal Hydro Generation Risk

The Federal hydro generation risk factor reflects the uncertain impacts that streamflow timing and volume have on monthly Federal hydro generation under specified hydro operation requirements. Federal hydro generation risk is accounted for in RevSim by inputting hydro generation estimates from the HYDSIM model and adjusting these results to account for efficiency losses associated with BPA standing ready to provide balancing reserve capacity, which is discussed below.

For FY 2018–2019, average monthly hydro generation risk is accounted for based on hydro generation estimates from the HYDSIM model for monthly streamflow patterns experienced from October 1928 through September 2008 (also referred to as the 80 water years). These monthly hydro generation data are developed by simulating hydro operations sequentially over all 960 months of the 80 water years. This analysis by HYDSIM is referred to as a continuous study. *See* Power Loads and Resources Study, BP-18-E-BPA-03, section 3.1.2.1.1, regarding HYDSIM, continuous study, and 80 water years.

For each of the 80 water years, monthly Heavy Load Hour (HLH) and Light Load Hour (LLH) energy splits for the Federal system hydro generation are developed for each fiscal year of the rate period based on analyses by the Hourly Operating and Scheduling Simulator (HOSS) Model, which incorporate results from HYDSIM hydro regulation studies. *See* Power Loads and Resources Study, BP-18-E-BPA-03, § 3.1.2.1.4. These monthly HLH and LLH regulated hydro generation estimates are combined with monthly HLH and LLH independent hydro generation estimates developed from historical data to yield total monthly Federal HLH and LLH hydro generation.

Monthly values for Federal hydro generation for each of the 80 historical water years are provided in Documentation Table 1 for FY 2018 and Table 2 for FY 2019. Monthly values for Federal hydro HLH generation ratios for each of the 80 historical water years are provided in Documentation Table 3 for FY 2018 and Table 4 for FY 2019.

Adjustments are made to the average monthly hydro generation in the 80 water year data to represent efficiency losses associated with standing ready to provide balancing reserve capacity for load and wind variability. A significant factor in these adjustments is the shift of hydro generation from HLH to LLH. The generation adjustments are reported in terms of HLH, LLH, and flat energy adjustments in Documentation Tables 5–7 for FY 2018 and Tables 8–10 for FY 2019. These generation data are added to the values presented in Documentation Tables 1–2 to yield the final monthly Federal hydro generation for each of the 80 water years.

The monthly Federal hydro generation data are input into RevSim to quantify the impact that Federal hydro generation variability has on PS secondary energy sales and revenues, balancing power purchases and expenses, and net revenues for 3,200 two-year simulations (FY 2018–2019). The PS secondary energy sales data are input into the PS Transmission and Ancillary Services Expense Risk Model to calculate these expenses for 3,200 two-year simulations. *See* section 4.1.1.1.2.5 below regarding the PS Transmission and Ancillary Services Expense Risk Model.

The water year sequences developed for each game for PNW hydro generation are also used for Federal hydro generation, resulting in a consistent set of PNW and Federal hydro generation being used for each game in AURORAxmp® and RevSim. *See* Power Market Price Study and Documentation, BP-18-E-BPA-04, section 2.3.3.1, regarding the development of water year sequences for PNW hydro generation.

4.1.1.1.5.2. BPA Load Risk

The BPA load risk factor represents the impacts that variability in the economy and temperature can have on PS revenues and expenses. Under the TRM, fluctuations in customer loads and revenues are considered as changes in Tier 1 loads, specifically through the Load Shaping and Demand charges. Load fluctuations are also reflected as changes in secondary energy revenues and balancing power purchase expenses. The level of regional economic activity affects the annual amount of load placed on BPA. Weather and climate conditions cause real-time and monthly variations in loads, especially during the winter and summer when heating and cooling loads are highest. BPA annual load growth variability and monthly load variability due to weather are derived from PNW load variability simulated in the load risk model for the WECC. *Id.* § 2.3.2.1. BPA load variability is derived such that the same percentage changes in PNW loads are used to quantify BPA load variability.

While the load risk model considers WECC-wide loads for AURORAxmp®, only the PNW component of the load risk is applied to BPA loads for the revenue simulation.

4.1.1.1.5.3. CGS Generation Risk

The CGS generation risk factor reflects the impact that variability in the output of CGS has on the amount of PS secondary energy sales and balancing power purchases estimated by RevSim. The source of the CGS generation risk data input into RevSim is AURORAxmp®, which simulates these data when calculating electricity prices. *See id.* section 2.3.5.1 regarding the methodology used in quantifying CGS generation risk.

4.1.1.1.5.4. PS Wind Generation Risk

The PS wind generation risk factor reflects the uncertainty in the amount and value of the energy generated by the portions of the Condon, Klondike I and III, Stateline, and Foote Creek I and IV wind projects that are under contract to BPA.

The uncertainty in the amount of energy generated by BPA's portions of these wind projects is simulated in the PNW Hourly Wind Generation Risk Model, which is described in the Power Market Price Study and Documentation, BP-18-E-BPA-04, section 2.3.4.1. Since the PNW Hourly Wind Generation Risk Model includes the output of wind projects that do not serve BPA loads, the results from this model are scaled such that the average wind generation output is equal to the forecast wind generation in the Power Loads and Resources Study, BP-18-E-BPA-03.

The simulated monthly wind generation results are specified in terms of flat energy. Results shown in Documentation Figure 1 are the monthly flat energy output for all wind projects during FY 2018–2019 at the 5th, 50th, and 95th percentiles. These monthly flat energy values are input into RevSim, where they are converted into monthly HLH and LLH energy values by applying HLH and LLH shaping factors that are associated with these wind projects. The source of these HLH and LLH shaping factors is the data used to compute the monthly HLH and LLH wind generation values included under Other Federal Generation in the Power Loads and Resources Study, BP-18-E-BPA-03, section 3.1.3.

The uncertainty in the value of the wind generation output is calculated in RevSim based on the differences between (1) the monthly weighted average purchase prices for all the output contracts between wind generators and BPA and (2) the wholesale electricity prices at which BPA can sell the amount of variable energy produced. The output contracts specify that BPA pays for only the amount of energy produced. The risk of the value of the wind generation output is computed in RevSim in the following manner: (1) subtract from expenses the expected monthly payments for the expected output from all the wind projects; (2) on a game-by-game basis, compute the monthly payments for the output from all the wind projects; and (3) on a game-by-game basis, compute the revenues associated with the wind generation from all the projects.

Results shown in Documentation Tables 11–12 report information from which the value of wind generation during FY 2018–2019 can be observed at expected monthly flat energy output levels and variable monthly electricity prices. Total deterministic wind generation purchase costs and total revenues earned from the sale of all wind generation at average, 50th percentile, 5th percentile, and 95th percentile electricity prices estimated by AURORAxmp® are provided, with the value of the wind generation being the difference between the revenues earned and purchase costs paid.

4.1.1.1.5.5. PS Transmission and Ancillary Services Expense Risk

The PS transmission and ancillary services expense risk factor represents the uncertainty in PS transmission and ancillary services expenses relative to the expected values of these expenses included in the power revenue requirement. Those expected values are $106.1 million during FY 2018 and $102.6 million during FY 2019. *See* Power Revenue Requirement Study Documentation, BP-18-E-BPA-02A, Table 3A. This risk is modeled in the PS Transmission and Ancillary Services Expense Risk Model.

The modeling of this risk is based on comparisons between monthly firm PTP Network transmission capacity that PS has under contract, the amount of existing firm contract sales, and the variability in secondary energy sales estimated by RevSim. Expense risk computations reflect how transmission and ancillary services expenses vary from the cost of the fixed, take-or-pay firm PTP Network transmission capacity that PS has under contract. Because PS has more firm PTP Network transmission capacity under contract than it has firm contract sales, the probability distribution for these expenses is asymmetrical. This asymmetry occurs because PS does not incur the costs of purchasing additional transmission capacity until the amount of secondary energy sales exceeds the amount of residual firm transmission capacity after serving all firm sales.

Transmission and ancillary services expenses will increase under conditions in which PS sells more energy than it has firm PTP Network transmission rights. Alternatively, transmission and ancillary services expenses will remain unchanged under conditions in which PS sells less energy than it has firm PTP Network transmission rights.

Results shown in Documentation Figures 2 and 3 indicate how FY 2018–2019 transmission and ancillary service expenses vary depending on the amount of secondary energy sales. In these figures, the PS transmission and ancillary services expenses do not fall below $75 million in FY 2018 and $75 million in FY 2019, regardless of the amount of secondary energy sales. This result is because PS must pay for the take-or-pay firm transmission capacity it has under contract. Included in these expenses are deterministic costs for the take-or-pay firm transmission capacity the PS has under contract on the Southern (AC and DC) Interties.

Results shown in Documentation Figures 4 and 5 reflect the probability distributions for transmission and ancillary service expenses during FY 2018–2019. These figures indicate how often transmission and ancillary service expenses fall within various expense ranges.

4.1.1.1.5.6. 4(h)(10)(C) Credits

The 4(h)(10)(C) credit risk results are quantified in an external risk model and input into RevSim. These results reflect the uncertainty in the amount of 4(h)(10)(C) credits BPA receives from the U.S. Treasury. Section 4(h)(10)(C) of the Northwest Power Act allows BPA to allocate its expenditures for systemwide fish and wildlife mitigation activities to various purposes. The credit reimburses BPA for its expenditures allocated to the non-power purposes of the Federal hydro projects, and BPA reduces its annual Treasury payment by the amount of the credit. The 4(h)(10(C) credit risk analysis performed in this study estimates the amount of 4(h)(10)(C) credits available for each of the 80 water years for FY 2018–2019 by first summing the costs of the operating impacts on the hydro system (*i.e.*, power purchase expenses), direct program expenses, and capital costs associated with BPA's fish and wildlife mitigation measures. The resulting total cost is multiplied by 0.223 (22.3 percent is the percentage of the FCRPS attributed to non-power purposes) to yield the amount of 4(h)(10)(C) credits available for each of the 80 water years.

Operating impact costs are calculated for each of the 80 water years for FY 2018–2019 by multiplying spot market electricity prices from AURORAxmp® by the amount of power purchases (aMW) qualifying for 4(h)(10)(C) credits. The amount of power purchases qualifying for 4(h)(10)(C) credits is derived outside of RevSim and is used to calculate the dollar amount of the 4(h)(10)(C) credits. A description of the methodology used to derive the amount of power purchases associated with the 4(h)(10)(C) credits is contained in the Power Loads and Resources Study, BP-18-E-BPA-03, section 3.3. The 4(h)(10)(C) credit power purchase amount for FY 2018 is reported in Table 6.1.1 and for FY 2019 in Table 6.1.2 in the Power Loads and Resources Documentation, BP-18-E-BPA-03A.

The direct program expenses and capital costs for FY 2018–2019 do not vary by water volume or flow timing and are documented in the Power Revenue Requirement Study Documentation, BP-18-E-BPA-02A, sections 3 and 4. A summary of the costs included in the 4(h)(10)(C) calculation and the resulting credit for each fiscal year are shown in Table 13 of this Study's documentation.

Results shown in Documentation Figures 6 and 7 reflect the probability distributions for the 4(h)(10)(C) credit during FY 2018–2019. The average 4(h)(10)(C) credit for the 3,200 games is \$96.6 million for FY 2018 and \$97.5 million for FY 2019. These values are included in the revenue forecast component of the Power Rates Study, BP-18-E-BPA-01, section 9.4.1.
The 4(h)(10)(C) credit for each of the 3,200 games is included in the net revenue provided to the ToolKit.

4.1.1.1.5.7. Electricity Price Risk (Market Price and Critical Water AURORAxmp® Runs)

Results from two runs of the AURORAxmp® model are used in this Study. One run, which uses hydro generation for all 80 water years, is referred to as the "market price run." The other run, which uses hydro generation for only the critical water year, 1937, is referred to as the "critical water run." *See also* Power Market Price Study and Documentation, BP-18-E-BPA-04, § 2.4. Both runs produce 3,200 games of monthly HLH and LLH prices for FY 2018–2019. Figures 1 and 2 of this Study provide a summary of the average monthly HLH and LLH prices for each of these AURORAxmp® runs.

Prices from the market price run are used by RevSim to develop secondary energy revenues, firm surplus energy revenues, balancing power purchase expenses, and system augmentation for FY 2018–2019. They are also used to compute 4(h)(10)(C) credits that are computed external to, but input into, RevSim. These values are provided to RAM2018 to develop rates for FY 2018–

2019. Prices from the market price run are also used to incorporate risk in the operating net revenues calculated by RevSim and provided to the ToolKit. *See* section 4.1.1.2.3 below for a description of this process.

Prices from the critical water run are used to compute the system augmentation costs provided to RAM2018 for ratesetting purposes. Prices from the critical water run are also used to incorporate system augmentation expense risk in the operating net revenues calculated by RevSim and provided to the ToolKit. *See* section 4.1.1.2.2 below for a description of this process.

4.1.1.2 RevSim Model Outputs

RevSim model outputs are provided to RAM2018, the ToolKit model, and the revenue forecast component of the Power Rates Study, BP-18-E-BPA-01, Chapter 9.

4.1.1.2.1 System Augmentation Costs and Firm Surplus Energy Revenues

For the rate period, the deterministic values for system augmentation costs provided for input into RAM2018 are calculated by multiplying the system augmentation amount (aMW) by the average AURORAxmp® price from the critical water run. The source of the system augmentation amounts is the Power Loads and Resources Study, BP-18-E-BPA-03, section 4.2. A summary of the system augmentation costs calculation in this Study is shown in Documentation Table 14.

The system augmentation costs included in the net revenues provided for input into ToolKit represent the uncertainty in the cost of system augmentation purchases not made prior to setting rates. The uncertainty in the cost of system augmentation considers electricity price risk associated with meeting system augmentation needs. RevSim calculates the system augmentation cost risk associated with each of the 3,200 games for each fiscal year. These variable cost values replace the deterministic values for system augmentation costs provided to RAM2018.

Firm surplus energy revenues are treated in a manner similar to system augmentation costs. The deterministic values for firm surplus energy revenues provided to RAM2018 are calculated by multiplying the firm surplus energy amount (aMW) by the average AURORAxmp® price from the market price run. The source of the firm surplus energy amounts is the Power Loads and Resources Study, BP-18-E-BPA-03, section 4.3. The inclusion of the firm surplus energy revenues in RAM2018 reduces rates, since it is a revenue credit. This inclusion in RAM2018 as a firm sale also reduces the total amount of surplus energy (aMW) such that loads and resources are in balance on a firm energy basis. Thus, the net secondary energy revenue analysis in RevSim reflects only secondary energy values. A summary of the firm surplus energy revenues calculation is shown in Documentation Table 15.

4.1.1.2.2 Secondary Energy Sales/Revenues and Balancing Power Purchases/Expenses

RevSim calculates secondary energy sales and revenues under various load, resource, and market price conditions. A key attribute of RevSim is that each month is divided into two time periods: Heavy Load Hours and Light Load Hours. For each simulation, RevSim calculates Power Services' HLH and LLH load and resource conditions and determines HLH and LLH secondary energy sales and balancing power purchases.

Included in this calculation are the additional amounts of secondary energy revenues that result from the forward power purchases of 100 aMW in FY 2018 and 100 aMW in FY 2019, which were acquired to provide Southeast Idaho Load Service (SILS) upon termination of the BPA-PacifiCorp Exchange Agreement. Although the SILS loads are included in the loads and in the calculation of system augmentation within the Power Loads and Resources Study, BP-18-E-BPA-03, the amounts of these forward power purchases are not included. Once the amounts of these forward power purchases are used to serve the SILS loads, the amounts of secondary energy marketable at Mid-C increase due to the reductions in firm load obligations associated with SILS. *See* Power Loads and Resources Study, BP-18-E-BPA-03, section 3.1.4, regarding the treatment of SILS forward power purchases, and Power Loads and Resources Study Documentation, BP-18-E-BPA-03A, Tables 1.2.1, 1.2.2, and 1.2.3, where the SILS loads are embedded in the total load values.

Losses on BPA's transmission system, which reduce the amount of resource output that can be delivered and sold beyond the busbar, are incorporated into RevSim by reducing by 2.97 percent the Federal hydro generation, CGS output, and wind generation that BPA has under contract. Additional incremental loss percentages (above the 2.97 percent) are applied to the Green Springs, Lost Creek, and Cowlitz Falls independent hydro projects. These losses are 4.45 percent for Green Springs, 4.45 percent for Lost Creek, and 0.5 percent for Cowlitz Falls. *See* Power Loads and Resources Study, BP-18-E-BPA-03, §3.1.5.

Electricity prices estimated by AURORAxmp® from the market price run are applied to the secondary energy sales and balancing power purchase amounts to determine secondary energy revenues and balancing power purchases expenses. These HLH and LLH revenues and expenses are then combined with other revenues and expenses to calculate PS operating net revenues.

4.1.1.2.3 Valuing Extraregional Marketing in RevSim

Given that BPA has access to extraregional markets (*e.g.*, California-Oregon Border (COB), Nevada-Oregon Border (NOB) and other points of delivery contiguous to the California Independent System Operator (CAISO)), BPA can reasonably expect to participate in these markets and receive a premium for corresponding sales. For the BP-18 rate period, BPA has incorporated a modeling extension into RevSim that models the value that can be obtained from making extraregional sales. Extraregional sales include CAISO transactions as well as bilateral transactions at COB and NOB, where BPA realizes a premium for the latter on the presumption that such energy will be remarketed into California. RevSim allocates surplus energy sales between Mid-C, COB, and NOB such that it maximizes surplus energy revenues. This allocation takes into consideration the relative price spreads between COB, NOB, and Mid-C; the amount of available transmission capacity on the interties; and the amount of excess available firm transmission capacity on the Southern Interties that PS has under contract. The source of the available excess transmission capacity and the price spreads is AURORAxmp®. *See* Power Market Price Study and Documentation, BP-18-E-BPA-04, § 2.3.8.1 and § 2.1, respectively.

The excess available firm transmission capacities that PS has under contract on the Southern Interties are represented by deterministic data that are input into RevSim. Results from the WECC-wide dispatch process in AURORAxmp® provide a distribution of modeled transmission capacity constraints. Therefore, for a given game, RevSim is able to determine whether all or only a portion of PS excess firm transmission capacity on the Southern Interties is available for export sales.

BPA recognizes that extraregional sales incur incremental transaction costs that are not observed at Mid-C. Such transaction costs include contractual fees associated with third-party contracts that BPA uses to market power into the CAISO. The transaction costs also include liquidity concerns in the bilateral market. To model these costs, BPA establishes a coefficient α that discounts the price spread between the relevant California hub (*i.e.,* COB or NOB) and Mid-C, both calculated by AURORAxmp®. The coefficient is a constant parameter calculated by taking the weighted average share of the California – Mid-C price spread that BPA is expected to realize, suggested by historical FERC Electric Quarterly Reports (EQR) data. Staff analyzed EQR data for the period Q3 2013 through Q1 2016 and determined that 29 percent of the observations were direct CAISO transactions, while 71 percent were bilateral transactions.

Currently, in order to sell into the CAISO, BPA uses third-party contracts, which include a contract fee. Thus, for this class of extraregional transactions BPA constructed the model in a manner that would expect $|\alpha| < 1$, which accounts for the transaction cost of the contract fee. BPA expects that bilateral transactions realize the full California – Mid-C price spread, because the third-party contracts are not required to participate in this market.

BPA's third-party contracts expire on an annual basis (because California recalculates BPA's emissions rate each year). Therefore, BPA currently does not have contracts in place to continue marketing surplus power inventories directly in the CAISO during the BP-18 rate period. BPA assumes that the absence of third-party contracts during the rate period implies that these inventories will be marketed at Mid-C, given the uncertainty of whether the bilateral market has enough liquidity to accommodate inventories that otherwise would have been marketed directly into the CAISO. Because α is zero for Mid-C transactions, the weighted average α parameter used to discount the value of extraregional transactions reduces to the proportion of bilateral transactions in the EQR data, which is 71 percent.

This modeling extension adds $14.4 million in FY 2018 and $19.7 million in FY 2019 to the net secondary energy revenue credits as compared to modeling sales being made only at Mid-C.

4.1.1.2.4 Median Net Secondary Revenue Computations

Secondary energy revenues and balancing power purchases expenses for FY 2018–2019 are provided to RAM2018. These revenues and expenses are based on the median net secondary revenues (secondary energy revenues less balancing power purchases expenses) from the 3,200 games. The secondary energy sales and balancing power purchases passed to RAM2018, both measured in annual average megawatts, are the arithmetic means of these quantities over the 3,200 games for each fiscal year.

In a data set with an even number of values, the median value is the mean of the two middle values. Because these two middle games have specific qualities (*e.g.,* loads, resources, prices, and monthly shape) that may not be representative of the study as a whole, the mean of more than two middle games was used to smooth out any particular features of individual games. To avoid specific games distorting the results, the mean of 320 games was used. The values for secondary energy revenues and balancing power purchases expenses passed to RAM2018 are the arithmetic means of the secondary energy revenues and balancing power purchases expenses (calculated and reported separately to RAM2018) for the 320 middle games as measured by net secondary revenue (160 above the median net secondary revenue and 160 below).

Documentation Tables 16 and 17 provide summary calculations of the secondary energy sales revenues and balancing power purchase expenses provided to RAM2018 for FY 2018–2019. Documentation Tables 18 and 19 provide monthly values for the secondary energy sales/revenues and total power purchases/expenses provided to RAM2018 for FY 2018–2019. Annual secondary energy sales/revenues and total power purchases/expenses for FY 2018–2019 (based on the median approach described above) are reported in Documentation Table 20. The secondary energy revenues are $348.0 million for FY 2018 and $374.8 million for FY 2019. The total power purchases expenses are $56.9 million for FY 2018 and $50.7 million for FY 2019.

4.1.1.2.5 Net Revenue

RevSim results are used in an iterative process with ToolKit and RAM2018 to calculate PNRR and, ultimately, rates that provide BPA with a 95 percent TPP for the two-year rate period. The PS net revenue simulated in each RevSim run depends on the revenue components developed by RAM2018, which in turn depend on the level of PNRR assumed when RAM2018 is run. RevSim simulates intermediate sets of net revenue during this iterative process. The final set of PS net revenue from RevSim is the set that yields a 95 percent TPP without requiring additional PNRR.

Using 3,200 games of net revenue risk data simulated by RevSim and P-NORM and mathematical descriptions of the CRAC and RDC, the ToolKit produces 3,200 games of cash flow and annual ending reserves levels. The ToolKit calculates TPP from these games, and then analysts change the amounts of PNRR to achieve TPP targets.

A statistical summary of the annual net revenue for FY 2018–2019 simulated by RevSim using rates with $0 million in PNRR is reported in Table 1. PS net revenue over the rate period averages $30.6 million per year. This amount represents only the operating net revenues calculated in RevSim. It does not reflect additional net revenue adjustments in the ToolKit model caused by the output from P-NORM, interest earned on financial reserves, or impacts of the CRAC and RDC. The average net revenue in Table 1 of this Study will differ from the net revenue shown in the Power Revenue Requirement Study, BP-18-E-BPA-02, Table 1, which shows the results of a deterministic forecast that does not account for system augmentation risk and uses median, rather than average, net secondary energy revenues.

4.1.2 P-NORM

4.1.2.1 Inputs to P-NORM

The primary source of risk estimates in P-NORM is the judgment of subject matter experts who understand how the expenses, and occasionally the revenue, associated with the sources of uncertainty might vary from the forecasts embedded in the baseline assumptions used in rate development. When available, historical data are used in the modeling of risks in P-NORM. Table 2 shows the 5th percentile, mean, and 95th percentile results from each of the risk models described below, along with the deterministic amount that is assumed in the revenue requirement for that risk. *See* Power Revenue Requirement Study Documentation, BP-18-E-BPA-02A, Table 3A.

4.1.2.1.1 CGS Operations and Maintenance (O&M)

CGS O&M uncertainty is modeled for Base O&M and Nuclear Electric Insurance Limited (NEIL) insurance premiums. P-NORM captures uncertainty around Base O&M and NEIL insurance costs. For Base O&M, P-NORM distributes the minimum- and maximum-based subject matter expert estimation of deviations from the expected value. For FY 2017, P-NORM models the maximum O&M expense as 2.5 percent greater than forecast and the minimum as 2.5 percent less than forecast. For FY 2018 and FY 2019, the maximums are 6 percent greater than forecast and the minimums are 4 percent less than forecast.

For NEIL insurance premiums, risk is modeled around forecast gross premiums and distributions based on the level of earnings on the NEIL fund. Historically, member utilities have received annual distributions based on the level of these earnings, and the net premiums they pay are lower as a result. NEIL premiums are modeled using a Program Evaluation and Review Technique (PERT) distribution. A PERT distribution is a type of beta distribution for which minimum, most likely, and maximum values are specified. For FY 2017, FY 2018, and FY 2019 the most likely is set to the base NEIL premium amount. For FY 2017, the maximum is set 2.5 percent higher than the most likely and the minimum is set to 2.5 percent lower than the most likely, less an annual distribution amount of $0.3 million. For FY 2018 and FY 2019, the maximum is set 5 percent higher than the most likely and the minimum is set to 5 percent lower, less an annual distribution amount of $0.3 million.

The distributions for CGS O&M are shown in Documentation Figure 8.

4.1.2.1.2 U.S. Army Corps of Engineers (Corps) and Bureau of Reclamation (Reclamation) O&M

For Corps and Reclamation O&M, P-NORM models uncertainty around the following:

- Additional costs if a security event occurs or if the security threat level increases
- Additional costs if a fish event occurs
- Additional extraordinary hydro system maintenance
- Additional costs due to a catastrophic event
- Additional costs due to new system requirements

For additional security costs, P-NORM assumes for FY 2017 through FY 2019 that there is a 2 percent probability that an event will occur that leads to a requirement for additional security at the Corps and Reclamation facilities. The additional annual cost if an event were to occur is the same for both the Corps and Reclamation at $3 million each.

Additional fish environmental costs are modeled similarly, with a 2 percent probability that an event that requires additional annual expenditures of $2 million each for both the Corps and Reclamation will occur in FY 2017 through FY 2019.

For additional extraordinary hydro system maintenance needs, P-NORM models the uncertainty that additional repair and maintenance costs at the Federal hydro projects could be incurred and the probability that an outage event could occur. For FY 2017 through FY 2019, this risk is modeled with a 2.5 percent probability that an event will occur that leads to an additional $5 million expense. This risk is modeled in the same way for both the Corps and Reclamation.

P-NORM models the expense cost of a catastrophic, systemwide event. This risk is modeled for FY 2017 through FY 2019 with a $30 million cost and an annual probability of 1 percent. This risk is modeled in the same way for both the Corps and Reclamation.

P-NORM models the expense cost related to increased compliance or regulatory requirements. This risk is modeled for FY 2017 through FY 2019 with a $5 million cost and an annual probability of 10 percent. This risk is modeled in the same way for both the Corps and Reclamation.

The distributions for total Corps and Reclamation O&M are shown in Documentation Figure 9.

4.1.2.1.3 Conservation Expense

For this expense item, P-NORM models uncertainty around Conservation Acquisition and Low-Income and Tribal Weatherization. Conservation Acquisition expense is modeled for each year from FY 2017 through FY 2019 using a PERT distribution. Conservation Acquisition expense is modeled with a minimum value of 90 percent of the amount in the revenue requirement, a most likely value equal to the amount, and a maximum value of 105 percent of the amount. *See* Power Revenue Requirement Study Documentation, BP-18-E-BPA-02A, Table 3A.

Low-Income and Tribal Weatherization expense variability is modeled using a PERT distribution for FY 2017 through FY 2019. These expenses are modeled with a minimum value of 95 percent of the amount in the revenue requirement, a most likely value equal to the amount, and a maximum value of 105 percent of the amount. *Id*. The distributions for Conservation Acquisition and Low-Income and Tribal Weatherization are shown in Documentation Figure 10.

4.1.2.1.4 Spokane Settlement

Within the BP-18 rate period, legislation could pass enacting a settlement with the Spokane Tribe similar to the settlement with the Colville Tribes. *See* Confederated Tribes of the Colville Reservation Grand Coulee Settlement Act, Pub. L. No. 103-436, 108 Stat. 4577 (Nov. 2, 1994) (as amended). For FY 2018 and FY 2019, the payments to the Spokane Tribe would equal 25 percent of the payments made to the Colville Tribes. *See* Power Revenue Requirement Study Documentation, BP-18-E-BPA-02A, Table 3A.

P-NORM includes an assumption of a 20 percent probability that the legislation will pass during the rate period, with an equal probability that payments would begin in FY 2018 or in FY 2019. The distributions for Spokane Settlement payments are shown in Documentation Figure 11.

4.1.2.1.5 Power Services Transmission Acquisition and Ancillary Services

For this cost item, P-NORM models uncertainty around expenses for Third-Party Transfer Service Wheeling and Third-Party Transmission and Ancillary Services. P-NORM models Third-Party Transfer Service Wheeling cost for each year from FY 2017 through FY 2019 with PERT distributions. For FY 2017, the minimum is set to 98 percent of the revenue requirement amount; the most likely value is set to the revenue requirement amount; and the maximum is set to 101 percent of the revenue requirement amount. For FY 2018, the minimum, most likely, and maximum are set to 96 percent, 100 percent, and 102 percent of the revenue requirement amounts. For FY 2019, the minimum, most likely, and maximum are set to 94 percent, 100 percent, and 103 percent of the revenue requirement amounts. Documentation Figure 12 shows the distribution for Third-Party Transfer Service Wheeling.

The cost of Third-Party Transmission and Ancillary Services is modeled for FY 2017 through FY 2019 using a PERT distribution with minimum and most likely values set to the revenue requirement amount. For FY 2017, FY 2018, and FY 2019, the maximums are set to 105 percent, 110 percent, and 116 percent of the revenue requirement amount. The distributions for Third-Party Transmission and Ancillary Services expense are shown in Documentation Figure 13.

4.1.2.1.6 Power Services Internal Operations Expenses

For Power Services Internal Operations Expenses, P-NORM models uncertainty around the following expenses:

- PS System Operations
- PS Scheduling
- PS Marketing and Business Support
- PS allocation of corporate general and administrative (G&A) costs

PS Internal Operations Expenses are modeled in P-NORM for FY 2017 through FY 2019. The costs in the PS Internal Operations Expense categories consist primarily of salaries. Risk in these categories is modeled based on the difference between staffing levels at the start of FY 2017 and the assumed staffing levels in the revenue requirement expense amounts for FY 2017, FY 2018, and FY 2019. Growth in staffing levels from the start of FY 2017 through FY 2019 is modeled in P-NORM. The difference between the modeled staffing level and the revenue requirement staffing level is multiplied by $108,000 per employee per fiscal year.

Documentation Figure 14 shows the distributions for total Internal Operations Costs, including Power Services' share of corporate G&A.

4.1.2.1.7 Fish & Wildlife Expenses

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

4.1.2.1.7.1. BPA Direct Program Costs for Fish and Wildlife Expenses

The costs of BPA's fish and wildlife program are uncertain, in large part because the actual pace of implementation cannot be known ahead of time and there is a chance that program components will not be implemented as planned. This does not reflect any uncertainty in BPA's commitment to the plans; instead, it reflects the reality that it can take time to plan and implement programs, and the expenses of the programs may not be incurred in the fiscal years in which BPA plans for them to be incurred. The uncertainty in fish and wildlife expenses is modeled using PERT distributions. For FY 2017, the minimum expense amount is set to 7.5 percent lower than the forecast amount; the most likely is set to 5 percent less than the forecast amount; and the maximum is set equal to the forecast amount. For FY 2018 and FY 2019, the minimums are set to 5 percent lower than the revenue requirement amount; the most likely values are set to 2.5 percent lower than the revenue requirement amount; and the maximums are set equal to the revenue requirement amounts. Documentation Figure 15 shows the distributions for the BPA Direct Program expense.

4.1.2.1.7.2. U.S. Fish and Wildlife Service (USFWS) Lower Snake River Hatcheries Expenses

Uncertainty in the expenses for the USFWS Lower Snake River Hatcheries is modeled as a PERT distribution with a minimum value set to 10 percent less than the forecast value, a most likely value 5 percent less than the forecast value, and a maximum equal to the forecast value. Documentation Figure 16 shows the distributions for risk over the Lower Snake River Hatcheries expense.

4.1.2.1.7.3. Bureau of Reclamation Leavenworth Complex O&M Expenses

P-NORM models uncertainty of the O&M expense of Reclamation's Leavenworth Complex using a discrete risk model. A discrete risk is defined using a set of specified values, with probabilities assigned to each value. In a discrete distribution, only the specified values can be drawn, as opposed to a continuous distribution, in which the set of possible values is not specified and any value between the minimum and maximum can be drawn. Leavenworth Complex O&M risk is modeled with a 1 percent probability of incurring an additional $1 million expense in each year. The revenue requirement amounts for Bureau of Reclamation Leavenworth Complex O&M for FY 2017, FY 2018, and FY 2019 are included in the Bureau's O&M budget, which is discussed in section 4.1.2.1.2 above. Documentation Figure 17 shows the distributions for Leavenworth Complex O&M expense.

4.1.2.1.7.4. Corps of Engineers Fish Passage Facilities Expenses

P-NORM models uncertainty of the cost of the fish passage facilities for the Corps using a discrete risk model, with a 1 percent probability of incurring an additional $1 million expense in each year. The revenue requirement amounts for Corps of Engineers Fish Passage Facilities Expenses for FY 2017, FY 2018, and FY 2019 are included in the Corps' O&M budget, which is discussed in section 4.1.2.1.2 above. Documentation Figure 18 shows the distributions for Fish Passage Facilities expense.

4.1.2.1.8 Interest Expense Risk

P-NORM models the impact of interest rate uncertainty associated with new debt issuances during the forecast period and the resulting interest expense impact. For FY 2017 through FY 2019, the amount of planned new borrowing is $897 million, $601 million, and $387 million respectively. The planned borrowings (Power Revenue Requirement Study Documentation, BP-18-E-BPA-02A, Tables 7A and 8A) are used to calculate expected interest expense on long-term debt and appropriations for the revenue requirement. This analysis assesses the potential difference in interest expense on long-term debt and appropriations from the amount rates are set to recover in the revenue requirement.

In each fiscal year, planned new borrowings occur on a monthly basis for different amounts each month, with different term lengths. *See* Power Revenue Requirement Study Documentation, BP-18-E-BPA-02A, Table 7A. P-NORM models uncertainty in the interest rate BPA will eventually receive when these borrowings occur. The analysis does not model uncertainty in the amount borrowed, term length of the borrowing, or timing of the borrowing.

P-NORM uses a historical database of interest rates as the basis to forecast future uncertainty in interest rates. The database was generated from 20 years of historical daily data from 1994 to 2014 that includes each interest rate term (for example one year, two year, …thirty year). This historical data is captured for U.S. Agency interest rates, which are the rates BPA pays for Federal borrowings and which are also used for modeling uncertainty in the rates for appropriations paid by BPA. The data source for these rates is Bloomberg Curve CO843. Historical data is also captured for taxable and tax-exempt interest rate indexes for AA-rated utilities. These are used as proxy rates for third-party financing related to Energy Northwest new capital and refinancing of existing Energy Northwest Debt. The data sources for these taxable and tax-exempt rates are Bloomberg Curve 903M and Bloomberg Curve 520M, respectively.

To model the interest expense uncertainty in P-NORM, for each game a starting date from the historical data set is selected and, for that date, the interest rate for each term length on the yield curve is captured. Then, the interest rates are captured for each term length on the yield curve 30 days later. This process is repeated for three years plus one month following the starting date, so that 37 interest rate data points for each term length are captured. This process is performed for Agency interest rates, AA Utility Taxable rates, and AA Utility Tax-Exempt interest rates.

The monthly returns are measured by taking the log return, also known as geometric return, which is the natural logarithm of the interest rate from one month less the natural logarithm of the interest rate of the prior month. This is similar to taking the percentage change, known as the simple return. The log return approach is preferred because it is more accurate at calculating small returns, which are more common when the time difference between returns is shorter (for example when the time difference is monthly, as in this analysis, versus annually). Also, the log returns possess the convenient mathematical property that they are additive through time; simple returns are not. Monthly returns are calculated for each interest rate product (Agency and AA Taxable), for each term length of that product and for each 30-day period for a full three years from the sample starting date. The 3,200 calculated monthly returns are used to create three-year projections of interest rates for each term length and for each interest rate product, all of which start from BPA's official starting interest rates in FY 2017.

For example, assume the sample starting date for Game 1 is June 5, 2001. The interest rate for the Agency product with a 10-year term in the first month of the 36-month projection is equal to the FY 2017 Agency 10-year interest rate from the official forecast multiplied by the calculated return from June 5, 2001, to July 5, 2001. The Agency 10-year interest rate is 3.70 percent. The June 5, 2001, 10-year Agency interest rate is 6.02 percent. The July 5, 2001, 10-year Agency interest rate is 6.19 percent. The log return of the two 10-year Agency interest rates equals

1.2094 percent (log(6.19) less log(6.02)). Taking the exponent of the log return yields 1.012168. Multiplying that factor by the Agency 10-year interest rate (1.012168 * 3.70 percent) yields 3.745 percent. That is the 10-year Agency interest rate for Game 1.

Continuing the example, to generate the Month 2 projection of the 10-year Agency interest rate for Game 1, the calculated rate from Month 1, 3.745 percent, is multiplied by the sampled return from July 5, 2001, to August 5, 2001. For the full projection, the process is repeated for all 36 months, for each term length on the yield curve, and for each interest rate product. In the second game, a new sample starting date is selected from the 20-year dataset, and the process is repeated for this new three-year historical window within the dataset.

Using this methodology, 3,200 games are run, generating interest rate projections of each term length for each interest rate product. Once all 3,200 projections are generated, they are adjusted so that the average interest rate for all 3,200 runs aligns with the expected interest rate in BPA's official FY 2019 interest rate forecast. Thus, this analysis captures the possible uncertainty around the expected interest expense in the revenue requirement and does not assess the expected value itself. The generated interest rates are then combined with the corresponding timing and term length of anticipated monthly borrowings in the repayment study to generate 3,200 projections of interest expense and appropriations expense. The difference between the deterministic forecast and the gamed amount is calculated for each issuance. The distribution of variation in Federal debt service expense, non-Federal debt service expense, and appropriations expense is shown in Documentation Figure 19.

4.1.2.1.9 CGS Refueling Outage Risk

In the spring of 2017, Energy Northwest will take CGS out of service for refueling and maintenance. The same will occur in the spring of 2019. There is uncertainty in the duration of these outages and thus uncertainty in the amount of replacement power BPA must purchase from the market, the amount of secondary energy available to be sold in the market, and the price of secondary energy at the time of any particular purchase or sale.

CGS outage duration risk is modeled as deviations from expected net revenue due to variability in the duration of the planned maintenance outages. Increases or decreases in downtime of the CGS plant result in changes in megawatthours generated, which results in decreased or increased net revenue for Power Services in FY 2017 and FY 2019. This revenue variability is a function of plant outage duration, monthly flat AURORAxmp® market prices, and monthly flat CGS energy amounts from RevSim.

The outage duration for FY 2017 was modeled with a minimum of 40 days, a maximum of 75 days, and a median of 54 days. For FY 2019, the minimum is 40 days, the maximum is 75 days, and the median is 54 days. The probability distribution of the outage durations is shown in Documentation Figure 20.

To calculate the impact of the outages on net revenue, 3,200 outage durations are simulated. The difference between the simulated duration from P-NORM and the deterministic duration assumed in RevSim is used to determine the number of additional days the plant is in or out of service in each month. These additional days in or out of service are then applied to the gamed CGS energy amounts from RevSim to calculate monthly megawatthour deviations. Monthly, flat AURORAxmp® prices (*see* Power Market Price Study and Documentation, BP-18-E-BPA-04, § 2.4) are then multiplied by the gamed generation deviations, resulting in a net revenue deviation. The distributions of revenue changes for FY 2017 and FY 2019 are shown in Documentation Figure 21.

4.1.2.1.10 Undistributed Reduction Risk

Based on the comments received in the 2016 IPR/CIR workshops (*see* Power Revenue Requirement Study, BP-18-E-BPA-02, § 2.1), spending increases for Power Services were reduced by $10 million in both FY 2018 and FY 2019. These expense reductions are reflected in the revenue requirement as undistributed reductions, meaning that the reduction has not been applied to any specific expense categories. *See* Power Revenue Requirement Study Documentation, BP-18-E-BPA-02A, Table 3A, Power Services Program Spending Levels Table.

P-NORM models uncertainty in achieving the undistributed reduction amount. The undistributed reduction model is dependent on the aggregate expense uncertainty modeled in P-NORM, described above. In each of the 3,200 games in P-NORM, the total of the expense deviations for each fiscal year is compared to the undistributed reduction amount. If the expense deviation is negative (that is, modeled expenses underrun the amount in the revenue requirement), then that expense underrun is treated as satisfying part of the needed undistributed reduction, up to the full amount of the undistributed reduction. For example, if in a given game the expense underrun is $5 million, then that underrun is treated as satisfying $5 million of the $10 million undistributed reduction. In that case, $5 million of the undistributed reduction remains to be handled. If the expense underrun were $25 million, then the full $10 million of the undistributed reduction would be met by the expense underrun. In that case the expense underrun is decreased by $10 million to $15 million, and $0 of the undistributed reduction remains to be handled.

BPA monitors expenses throughout the rate period and actively manages expenses to achieve the targeted undistributed reduction amount. In the event the undistributed reduction has not been fully achieved through random variation (as described above), active management of budgets will assist in achieving any remaining undistributed reduction amount. This mitigation is modeled in P-NORM by randomly drawing an undistributed reduction risk mitigation percentage between 0 and 100 percent. The unmitigated percent (1 less the drawn percentage) multiplied by the remaining undistributed reduction amount results in the unrealized portion of the undistributed reduction, increasing expenses by that amount. For example, if the remaining undistributed reduction amount is $5 million, and the risk mitigation percent drawn is 25 percent, then the additional expense is (1 - 0.25)*5 = $3.75 million.

4.1.2.2 P-NORM Results

The output of P-NORM is an Excel® file containing (1) the aggregate total net revenue deltas for all of the individual risks that are modeled and (2) the associated Net Revenue-to-Cash adjustments for each game for FY 2017, FY 2018, and FY 2019. Each run has 3,200 games. The ToolKit uses this file in its calculations of TPP. Summary statistics and distributions for each fiscal year are shown in Documentation Figure 22.

4.1.3 Net Revenue-to-Cash Adjustment

One of the inputs to the ToolKit (through P-NORM) is the NRTC Adjustment. Most of BPA's probabilistic modeling is based on impacts of various factors on net revenue. BPA's TPP standard is a measure of the probability of having enough cash to make payments to the Treasury. While cash flow and net revenue generally track each other closely, there can be significant differences in any year. For instance, the requirement to repay Federal borrowing over time is reflected in the accrual arena as depreciation of assets. Depreciation is an expense that reduces net revenue, but there is no cash inflow or outflow associated with depreciation. The same repayment requirement is reflected in the cash arena as cash payments to the Treasury to reduce the principal balance on Federal bonds and appropriations. These cash payments are not reflected on income statements. Therefore, in translating a net revenue result to a cash flow result, the impact of depreciation must be removed and the impact of cash principal payments must be added. The 3,200 NRTC adjustments calculated in P-NORM make the necessary changes to convert RevSim and P-NORM accrual results (net revenue results) into the equivalent cash flows so ToolKit can calculate reserves values in each game and thus calculate TPP.

The NRTC Adjustment is modeled probabilistically in P-NORM. P-NORM uses the deterministic NRTC Table as its starting point and includes 3,200 gamed adjustments for the Slice True-Up (*see* Power Rates Study, BP-18-E-BPA-01, Chapter 7, and Power GRSP II.R.), based on the calculated deviations in those revenue and expense items in P-NORM that are subject to the true-up. The NRTC table is shown in Documentation Table 21.

4.2 Power Quantitative Risk Mitigation

The preceding sections of this chapter describe the Power risks that are modeled explicitly, with the output of P-NORM and RevSim quantitatively portraying the financial uncertainty faced by PS in each fiscal year. This section describes the tools used to mitigate these risks—PS Reserves, the Treasury Facility, PNRR, the CRAC, and the RDC—and how BPA evaluates the adequacy of this mitigation.

The risk that is the primary subject of this study is the possibility that BPA might not have sufficient cash on September 30, the last day of a fiscal year, to fully meet its obligation to the U.S. Treasury for that fiscal year. BPA's TPP standard, described in section 2.3 above, defines a way to measure this risk (TPP) and a standard that reflects BPA's tolerance for this risk (no more than a five percent probability of any deferrals of BPA's Treasury payment in a two-year rate period). TPP and the ability of the rates to meet the TPP standard are measured in the ToolKit by applying the risk mitigation tools described in this section to the modeled financial risks described in the previous sections.

A second risk addressed in this study is within-year liquidity risk—the risk that at some time within a fiscal year BPA will not have sufficient cash to meet its immediate financial obligations (whether to the Treasury or to other creditors) even if BPA might have enough cash later in that year. In each recent rate proceeding, a need for reserves for within-year liquidity ("liquidity reserves") has been defined. This level is based on a determination of BPA's total need for liquidity and a subsequent determination of how much of that need is properly attributed to Power Services.

4.2.1 Power Risk Mitigation Tools

4.2.1.1 Liquidity

Cash and cash equivalents provide liquidity, which means they are available to meet immediate and short-term obligations. For the BP-18 rate period, Power Services has two sources of liquidity: (1) Financial Reserves Available for Risk Attributed to PS (PS Reserves) and (2) the Treasury Facility. These liquidity sources mitigate financial risk by serving as a temporary source of cash for meeting financial obligations during years in which net revenue and the corresponding cash flow are lower than anticipated. In years of above-expected net revenue and cash flow, financial reserves can be replenished so they will be available in later years.

4.2.1.1.1 PS Reserves

PS Reserves are not held in a PS-specific account. BPA has only one account, the Bonneville Fund, in which it maintains financial reserves. Staff in the BPA Chief Financial Officer's (CFO's) organization "attributes" part of the BPA Fund balance to the power generation function and part to the transmission function. Reserves attributed to Power do not belong to Power Services; they belong to BPA.

Financial reserves available to the generation function (Power Services) include cash and investments ("Treasury Specials") held in the BPA Fund at the Treasury plus any deferred borrowing. Deferred borrowing refers to amounts of capital expenditures BPA has made that authorize borrowing from the Treasury when BPA has not yet completed the borrowing. Deferred borrowing amounts can be converted to cash at any time by completing the borrowing.

As $49 million of PS reserves are considered not to be available for risk, that amount is not included in the starting financial reserves or any other part of the TPP calculation. These "Reserves Not For Risk" are made up of three categories:

1. $20 million of funds collected from customers under contracts that obligate BPA to perform energy efficiency-related upgrades to the customers' facilities.
2. $25 million in customer deposits for credit worthiness. These deposits are held in the BPA Fund as collateral for open trades.
3. $5 million for deposits received from third parties for cost-sharing of fish and wildlife project expenses.

4.2.1.1.2 The Treasury Facility

In FY 2008, BPA reached an agreement with the U.S. Treasury that made a $300 million short-term note available to BPA for up to two years to pay expenses. BPA has concluded that this note can be prudently relied on as a source of liquidity. In FY 2009, BPA and the Treasury agreed to expand this facility to $750 million.

The Treasury Facility is an agency liquidity tool, managed by Corporate Finance. For actual use, the Treasury Facility is not allocated or earmarked for specific business lines or purposes. For the purpose of modeling risk for the BP-18 rate period, all $750 million of the Treasury Facility is modeled to be available for PS risk. This allocation is made for TPP modeling purposes only.

4.2.1.1.3 Within-Year Liquidity Need

BPA needs to maintain access to short-term liquidity for responding to within-year needs, such as uncertainty due to the unpredictable timing of cash receipts or cash payments, or known timing mismatches. An illustrative timing mismatch is the large Energy Northwest bond payment due in the spring. Priority Firm Power rates are set to recover the entire amount of this payment, but by spring BPA will have received only about half of the PF revenue that will fully recover this cost by the end of the fiscal year. The PS within-year liquidity need of $320 million was determined in the BP-14 rate proceeding, and that amount continues to be used for ratesetting risk mitigation purposes.

4.2.1.1.4 Liquidity Reserves Level

No PS Reserves need to be set aside for within-year liquidity; *i.e.,* the Liquidity Reserves Level is $0. Instead, all PS Reserves are considered to be available for the year-to-year liquidity needed to support TPP.

4.2.1.1.5 Liquidity Borrowing Level

For this study, $320 million of the short-term borrowing capability provided by the Treasury Facility is considered to be available only for within-year liquidity needs, fully meeting the need for short-term liquidity. Thus, $430 million of the $750 million Treasury Facility is considered to be available for year-to-year liquidity for TPP.

4.2.1.1.6 Net Reserves

The concept of "Net Reserves" is used in this study. The concept of Net Reserves simplifies the discussion of the above sources of liquidity by combining the two discrete sources into a single measure. Net Reserves is the amount of PS Reserves above zero, less any balance on the Treasury Facility. In each individual Monte Carlo game in the ToolKit, either PS Reserves are

$0 or higher and the balance on the Treasury Facility is $0, or PS Reserves are $0 and the balance on the Treasury Facility is $0 or higher. Thus, in a single game, PS Reserves and the balance on the Treasury Facility will not both be above $0. This is because the ToolKit models a positive outstanding balance on the Treasury Facility if and only if PS Reserves are depleted. This clear-cut relationship does not hold for expected values calculated from a set of multiple games. That is, it is mathematically possible for the expected value of ending reserves attributed to PS to be above zero and for the expected value of the outstanding balance on the Treasury Facility to be above zero. Net Reserves, which represent balances on the Treasury Facility as a negative reserves balance, provides a more intuitive representation of the interaction between the PS Reserves and Treasury Facility Borrowing statistics.

4.2.1.2 Planned Net Revenues for Risk

Analyses of BPA's TPP are conducted during rate development using current projections of PS Reserves and other sources of liquidity. If the TPP is below the 95 percent two-year standard established in BPA's Financial Plan, then the projected reserves, along with whatever other risk mitigation is considered in the risk study, are not sufficient to reach the TPP standard. This may be corrected by adding PNRR to the revenue requirement as a cost needing to be recovered by rates. This addition has the effect of increasing rates, which will increase net cash flow, which will increase the available PS Reserves and therefore increase TPP. No PNRR is needed to meet the TPP standard for the BP-18 rates, so PNRR is $0 for both FY 2018 and FY 2019.

PNRR is calculated in the ToolKit, described in section 3.1.5 above. If the ToolKit calculates TPP below 95 percent, PNRR can be iteratively added to the model in one or both years of the rate period (typically, PNRR is added evenly to both years). PNRR is added in $1 million increments until a 95 percent TPP is achieved. The calculated PNRR amounts are then provided to the Power Revenue Requirement Study, which calculates a new revenue requirement. This adjusted revenue requirement is then iterated through the rate models and tested again in ToolKit. If ToolKit reports TPP below 95 percent or TPP above 95 percent by more than the equivalent of $1 million in PNRR, PNRR adjustments are calculated again and reiterated through the rate models.

4.2.1.3 The Cost Recovery Adjustment Clause

In most power rates in effect since 1993, BPA has employed CRACs or Interim Rate Adjustments (IRAs) as upward rate adjustment mechanisms that can respond to the financial circumstances BPA experiences before the next opportunity to adjust rates in a rate proceeding. The Power CRAC explained here could increase rates for FY 2018 based on financial results for FY 2017. It also could increase rates for FY 2019 based on the accumulation of financial results for FY 2017 and FY 2018 (taking into account any Power CRAC applying to FY 2018 rates). The Power rates subject to the Power CRAC (and eligible for the Power RDC, section 4.2.1.4 below) are the Non-Slice Customer rate, the PF Melded rate, the Industrial Firm Power rate, and the New Resource rate. Additionally, some reserves-based Ancillary and Control Area Services rates, which are levied by Transmission Services, are subject to the Power CRAC. These rates are Regulating and Frequency Response Service, Operating Reserve – Spinning, and Operating Reserve – Supplemental. *See* Power GRSPs II.O–P and Transmission GRSP II.G.

4.2.1.3.1 Calibrated Net Revenue (CNR)

CNR is net revenue adjusted for certain debt management and contract-related transactions that affect the relationship between accruals and cash. The method for calculating Power CNR is described in Power GRSP II.O. Examples of the application of this method, including actions that change Federal depreciation, debt transactions that affect net revenue but not cash, and cash contract settlements, are described in Documentation Example 1.

4.2.1.3.2 Description of the Power CRAC

As described in the introduction to section 4.2 above and Power GRSP II.O, the CRAC for FY 2018 and FY 2019 is a potential annual upward adjustment in various power and transmission rates. The threshold for triggering the CRAC is an amount of Power Services' CNR accumulated since the end of FY 2016.

The Accumulated Calibrated Net Revenue (ACNR) threshold values will be set in July 2017, based on the terms specified in the Financial Reserves Policy. *See* Chapter 6. In this Initial Proposal, the ACNR threshold is set at the equivalent of $0 in PS Net Reserves, which is the minimum threshold allowed by the Policy. The ACNR threshold for each year is calculated by taking the difference between average ACNR and average Net Reserves across all 3,200 games in the ToolKit and adding that difference to the target Power CRAC threshold in terms of reserves.

As an example, assume that a given fiscal year's Power CRAC threshold in terms of reserves is supposed to be $0. If the average ACNR at the start of that fiscal year is $200 million and the average Net Reserves at the start of that fiscal year is $50 million, then the CRAC threshold in terms of ACNR for that year is $150 million ($0 + $200 – $50 = $150 million).

The Power CRAC will recover 100 percent of the first $100 million that ACNR is below the threshold. Any amount beyond $100 million will be collected at 50 percent up to the CRAC annual limit on total collection, or cap, of $300 million. For example, at an equivalent of negative $100 million in reserves at the end of the fiscal year, $100 million will be collected in the next year. At the equivalent of negative $150 million, $125 million will be collected ($100 million plus one-half of the next $50 million). The Power CRAC will be implemented only if the amount of the CRAC is greater than or equal to $5 million.

Calculations for the CRAC that could apply to FY 2018 rates will be made in July 2017; the corresponding calculations for possible adjustments to FY 2019 rates will be made in September 2018. A forecast of the year-end Power Services ACNR will be made based on the results of the Third Quarter Review and then compared to the thresholds for the CRAC and the RDC. *See* § 4.2.1.4 below. If the ACNR forecast is below the CRAC threshold, an upward rate adjustment will be calculated for the duration of the upcoming fiscal year. *See* Power GRSP II.O.

4.2.1.4 Reserves Distribution Clause (RDC)

One of BPA's financial policy objectives is to ensure that reserves do not accumulate to excessive levels. *See* § 2.1 above. The Power RDC is triggered if both BPA ACNR *and* Power Services' ACNR are above a threshold and provides a downward adjustment to the same power and transmission rates that are subject to the Power CRAC. In the same way that a CRAC passes costs of bad financial outcomes to BPA's customers, an RDC may pass benefits of good financial outcomes to BPA's customers. The total distribution is capped at $500 million per fiscal year. The RDC will be implemented only if the amount of the RDC is greater than or equal to $5 million. *See* Chapter 6 and Power GRSP II.P.

4.2.1.5 The NFB Adjustment

NFB (*N*MFS [National Marine Fisheries Service] *F*CRPS [Federal Columbia River Power System] *B*iOp [Biological Opinion]) risks arise from litigation over the FCRPS BiOp. NFB risks and mitigation are addressed through qualitative risk assessment and mitigation. *See* § 4.3.1 below.

4.2.2 ToolKit (VPP)

The ToolKit model is described in section 3.1.5, above. The inputs to the ToolKit for Power are shown in Documentation Figure 23.

4.2.2.1 ToolKit Inputs and Assumptions for Power

4.2.2.1.1 RevSim Results

The ToolKit reads in risk distributions generated by RevSim that are created for the current year, FY 2017, and the rate period, FY 2018–2019. TPP is measured for only the two-year rate period, but the starting Reserves Available for Risk for FY 2018 depend on events yet to unfold in FY 2017; these runs reflect that FY 2017 uncertainty. *See* section 4.1.1 for more detail on operating risk models.

4.2.2.1.2 Non-Operating Risk Model

The ToolKit reads in P-NORM distributions that are created for FY 2017–2019 and that reflect the uncertainty around non-operating expenses. *See* section 4.1.2 of this study for more detail on P-NORM.

4.2.2.1.3 Treatment of Treasury Deferrals

In the event that ToolKit forecasts a deferral of payment of principal to the Treasury, the ToolKit assumes that BPA will track the balance of payments that have been deferred and will repay this balance to the Treasury at its first opportunity. "First opportunity" is defined for TPP calculations as the first time Power Services ends a fiscal year with more than $100 million in net reserves. The same applies to subsequent fiscal years if the repayment cannot be completed in the first year after the deferral. This is referred to as "hybrid" logic on the ToolKit main page.

4.2.2.1.4 Starting PS Reserves

The FY 2017 starting PS reserves have a known value of $158.7 million based upon the FY 2016 Fourth Quarter Review. Each of the 3,200 games starts with this value. *See* section 4.2.1.1.1 above for a description of PS Reserves.

4.2.2.1.5 Starting ACNR

The FY 2017 starting ACNR value of $0 million is known from the definition of ANCR as being accumulated PS net revenue since the end of FY 2016. Each of the 3,200 games starts with this value.

4.2.2.1.6 PS Liquidity Reserves Level

The PS Liquidity Reserves Level is an amount of PS Reserves set aside (*i.e.*, not available for TPP use) to provide liquidity for within-year cash flow needs. This amount is set to $0. *See* § 4.2.1.1.4.

4.2.2.1.7 Treasury Facility

This study relies on all $750 million of BPA's Treasury Facility: $320 million for within-year liquidity needs, as described in section 4.2.1.1.2 above, and the remaining $430 million to support PS TPP.

4.2.2.1.8 Interest Rate Earned on Reserves

Interest earned on the both the cash component and the Treasury Specials component of PS Reserves, as well as interest paid on the Treasury Facility, is assumed to be 0.32 percent in FY 2017, 0.62 percent in FY 2018, and 0.84 percent in FY 2019.

4.2.2.1.9 Interest Credit Assumed in Net Revenue

An important feature of the ToolKit is the ability to calculate interest earned on PS reserves separately for each game. The net revenue games the ToolKit reads in from RevSim include deterministic assumptions of interest earned on reserves for each fiscal year; that is, the interest earned does not vary from game to game. To capture the risk impacts of variability in interest earned induced by variability in the level of reserves, in the TPP calculations the values embedded in the RevSim results for interest earned on reserves are backed out of all ToolKit games and replaced with game-specific calculations of interest credit. The interest credit assumptions embedded in RevSim results that are backed out are \$3.9 million for FY 2017, \$4.5 million for FY 2018, and \$5.4 million for FY 2019. *See* Power Revenue Requirement Study Documentation, BP-18-E-BPA-02A, Table 3A.

4.2.2.1.10 The Cash Timing Adjustment

The cash timing adjustment reflects the impact on earned interest of the non-linear shape of PS reserves throughout a fiscal year as well as the interest earned on reserves attributed to PS that are not available for risk and are not modeled in the ToolKit. The ToolKit calculates interest earned on reserves by making the simplifying assumption that reserves change linearly from the beginning of the year to the end. ToolKit takes the average of the starting reserves and the ending reserves and multiplies that figure by the interest rate for that year. Because PS cash payments to the Treasury are not evenly spread throughout the year but instead are heaviest in September, PS will typically earn more interest in BPA's monthly calculations than the straight-line method yields. Additionally, the ToolKit does not model Reserves Not For Risk (*see* § 4.2.1.1.1) or the interest earned from these. The cash timing adjustment is a number from the repayment study that approximates this additional interest credit earned on reserves throughout the fiscal year along with the interest earned on reserves attributed to PS that are not available for risk. The cash timing adjustments for this study are $4.3 million for FY 2017, $2.3 million for FY 2018, and $2.1 million for FY 2019.

4.2.2.1.11 Cash Lag for PNRR

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

4.2.3 Quantitative Risk Mitigation Results

Summary statistics are shown in Table 3.

4.2.3.1 Ending PS Reserves

Known starting PS Reserves for FY 2017 are $158.6 million. The expected values of ending net reserves are $90 million for FY 2017, $120 million for FY 2018, and $164 million for FY 2019. Over 3,200 games, the range of ending FY 2019 net reserves is from negative $430 million to positive $1,074 million. The rate adjustment mechanisms would produce a CRAC of $265 million or an RDC of $456 million (if Agency ANR is also high enough) in these extreme cases if the FY 2020 rates include mechanisms comparable to those included in the FY 2018–2019 rates. The 50 percent confidence interval for ending net reserves for FY 2019 is negative

$86 million to $279 million. ToolKit summary statistics for reserves and liquidity are in Documentation Figure 24 and Table 22.

4.2.3.2 TPP

The two-year TPP is 99.9 percent. In 3,200 games, there are no deferrals for FY 2017 or FY 2018. There are deferrals for FY 2019 in 0.1 percent of games, with an expected value over all games of less than $1 million.

4.2.3.3 CRAC and RDC

The Power CRAC triggers at the end of FY 2017, modifying rates for FY 2018, in 35 percent of games. The average Power CRAC amount is $31 million for FY 2018 (measured as the average amount across all 3,200 games). The Power CRAC also triggers at the end of FY 2018, modifying rates for FY 2019, in 37 percent of games. The average Power CRAC amount is $38 million for FY 2018.

The Power RDC does not trigger in any of the 3,200 games for FY 2018. The Power RDC triggers in 0.5 percent of games for FY 2019, yielding an average of $0.5 million.

Power CRAC and Power RDC statistics are shown in Table 3.

The thresholds and caps for the Power CRAC and Power RDC applicable to rates for FY 2018 and FY 2019 are shown in Tables 4 and 5. The BPA RDC Thresholds are shown in Table 6.

4.3 Power Qualitative Risk Assessment and Mitigation

The qualitative risk assessment described here is a logical analysis of the potential impacts of risks that have been identified but not included in the quantitative risk assessment. The qualitative analysis considers the risk mitigation measures that have been created, which are largely terms and conditions that define how possible risk events would be treated. If this logical analysis indicates that significant financial risk remains in spite of the risk mitigation measures, additional risk treatment might be necessary. The three categories of risk analyzed here are (1) financial risks to BPA arising from legislation over the FCRPS Biological Opinion; (2) financial risks to BPA or to Tier 1 costs arising from BPA's provision of service at Tier 2 rates; and (3) financial risks to BPA or to Tier 1 costs arising from BPA's provision of Resource Support Services.

4.3.1 FCRPS Biological Opinion Risks

Certainty that BPA can cover its fish and wildlife program costs is an important objective. Because of pending and possible litigation over BPA's FCRPS fish and wildlife obligations, it is impossible to determine now the approach to fish recovery and the associated costs that BPA will be required to implement during the rate period, FY 2018–2019.

The possibilities for FY 2018–2019 are many and mostly unknowable at this time and, as a result, probabilities cannot be estimated for any particular scenario that might be created. Because the uncertainty is open-ended, it is necessary to have an equally open-ended adjustment mechanism to ensure that BPA can fund its fish and wildlife obligations despite the uncertainty. This study includes two related features that help to mitigate the financial risk to BPA and its stakeholders caused by uncertainty over future fish and wildlife obligations under FCRPS BiOps and their financial impacts. These are the NFB Adjustment and the Emergency NFB Surcharge, collectively referred to as the NFB Mechanisms. Implementation details for the NFB Mechanisms are provided in Power GRSP II.Q.

The NFB Mechanisms will take effect should certain events, called trigger events, occur. An NFB Trigger Event is one of the following events that results in changes to BPA's FCRPS Endangered Species Act (ESA) obligations compared to those in the most recent BPA Final Proposal, as modified, prior to this Trigger Event:

- A court order in *National Wildlife Federation vs. National Marine Fisheries Service*, CV 01-640-RE, or any other case filed regarding an FCRPS BiOp issued by NMFS (also known as NOAA Fisheries Service) or the U.S. Fish and Wildlife Service, or any appeal thereof ("Litigation").
- An agreement (whether or not approved by the Court) that results in the resolution of issues in, or the withdrawal of parties from, Litigation.
- A new FCRPS BiOp including unplanned or unexpected implementation measures.
- A BPA commitment to implement Recovery Plans under the ESA that results in the resolution of issues in, or the withdrawal of parties from, Litigation.
- Actions needed for meeting obligations for the development of the Columbia River System Operations Environmental Impact Statement.

The fish and wildlife operation or fish and wildlife program (or both) that BPA implements in a fiscal year may not be the same as that assumed in the rate proposal. The "as modified" term used in the description of the NFB mechanisms means that BPA will first adjust for changes in operations due to non-trigger event reasons, as well as changes in operations due to prior NFB events to determine the baseline for calculating the financial effects of an NFB event.

The NFB Mechanisms protect the financial viability of BPA and its financial resources from the potentially large impact of changes in the operation of the Columbia River hydro system or in fish and wildlife program costs that are directly related to FCRPS BiOps and litigation over BiOps (as specified above).

4.3.1.1 The NFB Adjustment

The NFB Adjustment adjusts the Power CRAC for any year in the rate period if one or more NFB Trigger Events with financial effects occurred in the previous year (unless one or more Emergency NFB Surcharges, *see* § 4.3.1.2, in the previous year collected additional revenue equal to the financial effects). The adjustment allows the CRAC to collect more revenue under specific conditions. The NFB Adjustment could modify the CRAC Cap applicable to rates for FY 2018 or FY 2019. While the NFB Adjustment increases the revenue the CRAC can collect, it does not necessarily result in higher revenue collected. If the NFB Adjustment triggers but Power Services' ACNR is above the CRAC threshold specified in the Power GRSPs, there will be no adjustment to rates, because the CRAC will not trigger. It is possible to have a trigger event that does not reduce net revenue; these events do not trigger NFB Adjustments or Emergency NFB Surcharges.

4.3.1.2 The Emergency NFB Surcharge

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

The Emergency NFB Surcharge addresses the fact that the CRAC does not produce revenue until the year following the fiscal year in which financial effects of a Trigger Event are experienced. Thus, the financial benefit of the NFB Adjustment may be too late if BPA is in a Cash Crunch when a Trigger Event occurs. The surcharge may be implemented in FY 2018 if the events required to impose the surcharge occur in that fiscal year, or in FY 2019 if the requisite events occur in that year.

4.3.1.3 Multiple NFB Trigger Events

There can be multiple NFB Trigger Events in one year. If BPA is not in a Cash Crunch in such a year, then there will be only one final analysis near the end of the year that calculates the NFB Adjustment to the cap on the Power CRAC applicable to the next fiscal year. If BPA is in a Cash Crunch in such a year, there may be more than one Emergency NFB Surcharge calculated and applied during that year. For example, there could be more than one court order in FY 2018 that increases the financial impacts of operations in FY 2018. If BPA was in a Cash Crunch, there could be an Emergency NFB Surcharge calculated for each of the Trigger Events and applied during FY 2018. If BPA was not in a Cash Crunch in FY 2018, all of these triggering events would be included in the calculation of the single NFB Adjustment that would increase the cap on the Power CRAC applicable to FY 2019.

Each NFB Adjustment affects only one year. However, because the comparison used to calculate the NFB Adjustment is between the actual operation for fish and the operation assumed in the most recent Final Proposal (as modified prior by previously responded-to NFB Events), it is possible for a Trigger Event to affect operations for more than one year of the rate period. For example, a decision in FY 2017 may affect operations in both FY 2017 and FY 2018. The analysis of the total financial impact during FY 2017 for adjusting the cap on the CRAC applying to FY 2018 would be separate from the analysis of the total financial impact during FY 2018 for adjusting the cap on the CRAC applying to FY 2019 (or for implementing an Emergency NFB Surcharge during FY 2018). Increases in the financial impacts during FY 2019 are not covered by the NFB Adjustment, because incorporating those increases through an NFB Adjustment would require a CRAC during FY 2020, and the rates for FY 2020 are not covered by this Study. However, financial impacts during FY 2019 are covered by the Emergency NFB Surcharge provisions applicable to FY 2019.

4.3.2 Risks Associated with Tier 2 Rate Design

For the FY 2018–2019 rate period, there are four Tier 2 rate alternatives: the Tier 2 Short-Term, Tier 2 Load Growth, Tier 2 VR1-2014, and Tier 2 VR1-2016 rates. *See* Power Rates Study, BP-18-E-BPA-01, § 3.2.2. BPA has made most of the necessary power purchases to meet its load obligations at the Tier 2 rate for the rate period. BPA purchased three flat annual blocks of power from the market for delivery to BPA at Mid-C. *Id.*, § 3.2.2.1. BPA expects it will need to make an additional market purchase to meet its load obligation for Tier 2 in FY 2019 and expects to serve Tier 2 load in FY 2018 out of firm surplus energy. *See* Power Rates Study, BP-18-E-BPA-01, § 3.2.2.1. For this Initial Proposal, the additional obligation is valued at the augmentation price. *Id.,* § 3.2.2.4. Preventing risks associated with Tier 2 from increasing costs for Tier 1 or requiring increased mitigation for Tier 1 is one of the objectives guiding the development of the risk mitigation for the FY 2018–2019 rate period. *See* § 2.1 above.

4.3.2.1 Identification and Analysis of Risks

The qualitative assessment of risks associated with Tier 2 cost recovery identified several possible events that could pose a financial risk to either BPA or Tier 1 costs:

- The contracted-for power is not delivered to BPA.
- A customer's Above-Rate Period High Water Mark (Above-RHWM) load is lower than the amount forecast.
- A customer's Above-RHWM load is higher than the amount forecast.
- A customer does not pay for its Tier 2 service.
- A customer's Above-RHWM load is lower than its take-or-pay VR1-2016 rate amounts.

- The cost of BPA power purchases to meet Tier 2 obligations is higher than the cost allocated to the Tier 2 pool.

The following sections describe the analysis of these risks, which determines whether there is any significant financial risk to BPA or Tier 1 costs.

4.3.2.1.1 Risk: The Contracted-for Power Is Not Delivered to BPA

BPA has executed three standard Western Systems Power Pool (WSPP) Schedule C contracts for purchases made to meet its load obligations under Tier 2 rates for the rate period. Under the WSPP Schedule C contracts, if a supplier fails to deliver power at Mid-C, the contract provides for liquidated damages to be paid by the supplier. The liquidated damages cover the cost of any replacement power purchased by BPA to the extent the cost of the replacement power exceeds the original purchase price.

If there is a disruption in the delivery from Mid-C to the BPA point of delivery due to a transmission event, BPA will supply replacement power and pass through the cost of the replacement power to the Tier 2 purchasers by means of a Transmission Curtailment Management Service (TCMS) calculation. The Power Rates Study, BP-18-E-BPA-01, sections 5.4.5 and 5.6.1.5, explains how the TCMS calculation is performed for service at Tier 2 rates. BPA will base the TCMS cost on the amount of megawatthours that was curtailed and the Powerdex (or its replacement) Mid-C hourly index for the hour the event occurred. Based upon BPA's past experiences, it is not anticipated that such disruptions would affect a substantial number of hours in a year. The market index is a fair, unbiased estimate of the cost of replacement power; therefore, there is no reason to believe that if such events occur in a fiscal year BPA or Tier 1 would incur a net cost.

4.3.2.1.2 Risk: A Tier 2 Customer's Load is Lower than the Amount Forecast

Each customer provided BPA an election regarding its intention to meet none, some, or all of its Above-RHWM Load with Tier 2-priced power from BPA. Elections were made by September 30, 2011, for FY 2018 and FY 2019. Using the Above-RHWM Loads that were computed in the RHWM Process, which concluded in September 2016, and the customers' elections, BPA has determined each customer's Above-RHWM Load served at a Tier 2 rate for the BP-18 rate period. As noted in section 4.3.2.1 above, BPA has made or will make contractual commitments to purchase power sufficient to supply the necessary quantity of power at Tier 2 rates.

Even if the customer's actual load is lower than the BPA forecast, the terms of the customer's Contract High Water Mark (CHWM) contract obligate the customer to continue to pay the full cost of its purchases at the Tier 2 rates. This approach protects BPA and Tier 1 purchasers from financial impacts of this event. The customer's load reduction would free up some of the power BPA has contracted for, and BPA would remarket this power. BPA would return the value of the remarketed power to the customer by charging it less through the Load Shaping rate than it would otherwise have been charged. BPA would effectively credit the customer for the unneeded power at the Load Shaping rate, which is an unbiased estimate of the market value of the power; thus, there would be no net cost to BPA or Tier 1.

4.3.2.1.3 Risk: A Tier 2 Customer's Load is Higher than the Amount Forecast

This risk is the inverse of the previous risk. If a customer's load is higher than forecast by BPA and the customer's sources of power (the sum of the quantity of power at Tier 2 rates the customer committed to purchase, its Tier 1 power, and the amount of non-BPA power the customer committed to its load) are inadequate to meet its total retail load, BPA would obtain additional power from the market and charge the customer for this power at the Load Shaping rate. The Load Shaping rate is an unbiased estimate of the market cost of the power. The customer retains the primary obligation to pay for the additional power, and there would be no net cost to BPA or Tier 1.

4.3.2.1.4 Risk: A Customer Does Not Pay for its Service at the Tier 2 Rate

It is not possible for a customer to be in default on its Tier 2 charges and remain in good standing for its Tier 1 service. If a customer does not pay for its service at the Tier 2 rate, it will be in arrears for its BPA bill and will be subject to late payment charges. BPA may require additional forms of payment assurance if (1) BPA determines that the customer's retail rates and charges may not be adequate to provide revenue sufficient to enable the customer to make the payments required under the contract, or (2) BPA identifies in a letter to the customer that BPA has other reasonable grounds to conclude that the customer may not be able to make the payments required under the contract. If the customer does not provide payment assurance satisfactory to BPA, then BPA may terminate the CHWM contract.

4.3.2.1.5 Risk: A Customer's Above-RHWM Load is Lower than its Take-or-Pay Tier 2 Amounts

When customers subscribed to the Tier 2 VR1-2014 and VR1-2016 rates, they requested specific amounts of load to be served at these rates on a take-or-pay basis for the term of the rate alternative's application. Customers were eligible for amounts that were capped at levels based on BPA load forecasts completed the previous spring. Once customers requested an amount and BPA was successful purchasing that amount, then the customers became contractually committed to that purchase amount. Some customers elected, in accordance with section 10 of the CHWM contract, to have BPA remarket amounts of their purchases that are in excess of their Above-RHWM Load. These customers will continue to pay the full cost of the purchases they elected. BPA will allocate some of this power to the Tier 2 Short-Term cost pool at a market price. The remainder will be purchased to meet a portion of BPA's system augmentation need, if any, at the forecast system augmentation prices. Because BPA is selling the excess power at fixed prices to Short-Term customers and at fixed prices for augmentation needs, the revenues that will be received from Short-Term customers will equal the remarketing credits paid to Tier 2 customers, and there is no risk to BPA or Tier 1.

4.3.2.1.6 Risk: The Cost of BPA Power Purchases to Meet Tier 2 Obligations is Higher than the Cost Allocated to the Tier 2 Pool

In the event that BPA must make additional power purchases to meet its Tier 2 obligations, there is a risk that the cost of the purchase is greater (or less) than the cost applied to the Tier 2 cost pool. If the purchase cost is greater, then the Power net revenue will be reduced by the amount of the difference. As of this Initial Proposal, BPA expects it will need to make a purchase to meet the Tier 2 obligation in FY 2019 and expects to serve Tier 2 load in FY 2018 out of firm surplus energy. *See* Power Rates Study, BPA-18-E-BPA-01, § 3.2.2.1. The cost of the power purchase is forecast at the augmentation price; the cost applied to the Tier 2 pool is the same amount. For FY 2019, if the actual purchase price is greater than the augmentation price, the cost difference will be known by the time of the Final Proposal, and the Tier 2 rate will be reset accordingly. For FY 2018, the augmentation price is assumed to be high enough to cover any risk to Tier 1 of a cost shift, should observed actual market prices exceed forecast market prices upon which this Tier 2 rate is based. This purchase is anticipated to occur prior to the publication of BPA's BP-18 Final Proposal in the summer of 2017. At that point, the actual purchase price will be known and the cost of the purchase will be applied to the Tier 2 cost pool, resulting in no risk to BPA or Tier 1.

4.3.3 Risks Associated with Resource Support Services Rate Design

Resource Support Services (RSS) are resource-following services that help financially convert the variable, non-dispatchable output from non-Federal generating resources to a known, guaranteed shape. Operationally, BPA serves the net load placed on it after taking into consideration the variability of the customer's loads and resources. RSS include Secondary Crediting Service (SCS), Diurnal Flattening Service (DFS), and Forced Outage Reserve Service (FORS). The customers that have elected to purchase RSS and their elections are listed in the Power Rates Study Documentation, BP-18-E-BPA-01A, Table 3.13.

4.3.3.1 Identification and Analysis of Risks

The RSS pricing methodology is a value-based methodology that relies on a combination of forecast market prices and costs associated with new capacity resources rather than aiming to capture the actual cost of providing these services. Therefore, the primary risk for BPA is that the "true" value of providing these services will be more or less than the established rate. This pricing approach makes the sale of RSS no different from that of any other service or product BPA sells into the open market. Moreover, there is currently no transparent and/or liquid market for such services, which makes after-the-fact measurements of the "true" value and the price paid to BPA difficult. BPA does not intend to quantify the cost of each operational decision, which means that BPA is not able to measure the cost of following a customer's load separately from the cost of following its resources when a customer is taking some combination of RSS. Therefore, in addition to the difficulty in quantifying the after-the-fact value difference between the price paid and the "true" value, it would be extremely challenging, if not impossible, to measure the difference between the price received by BPA and the cost incurred by BPA.

The total forecast cost of RSS is about $4 million annually. *See* Power Rates Study, BP-18-E-BPA-01, § 5.6. The magnitude of the risk of miscalculation of these RSS costs is not large enough to affect TPP calculations.

4.3.4 Qualitative Risk Assessment Results

4.3.4.1 Biological Opinion Risks

The financial risks deriving from possible changes to Biological Opinions are adequately mitigated by the NFB mechanisms. *See* § 4.3.1.1 above and Power GRSP II.Q.

4.3.4.2 Risks Associated with Tier 2 Rate Design

Tier 2 risks are adequately mitigated by the terms and conditions of service at the Tier 2 rate and BPA's credit risk policies, and no residual Tier 2 risk is borne by BPA or Tier 1.

4.3.4.3 Risks Associated with Resource Support Services Rate Design

BPA uses a pricing construct that does not lead to prices for RSS that are systematically too high or systematically too low. There is not a significant financial risk that the cost would affect the Composite or Non-Slice cost pools or BPA generally, and as a consequence, there is no quantification or mitigation of RSS risks in this study.

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5. TRANSMISSION RISK

5.1 Transmission Quantitative Risk Assessment

This chapter describes the uncertainties pertaining to Transmission Services' finances in the context of setting transmission rates. Section 5.2 describes how BPA determines whether its risk mitigation measures are sufficient to meet the Treasury Payment Probability (TPP) standard given the risks detailed in this chapter.

Variability in Transmission revenues is modeled in RevRam, as described in section 5.1.2. Variability in Transmission expenses and Net Revenue-to-Cash (NRTC) adjustments is modeled in T-NORM, as described in section 5.1.3. The results of these quantitative risk models are provided to ToolKit, which performs quantitative risk mitigation, as described in section 5.2.

5.1.1 RevRAM – Revenue Risk

See section 3.1.2.2 for an overview of RevRAM. The following sections describe the uncertainties modeled in RevRAM.

5.1.1.1 Network Integration Service Revenue Risk

Risks in the NT revenue forecast arise from uncertainty in the load forecast, which is the basis for the NT sales and revenue forecast. The load forecast is based on predicted year-to-year NT load growth. Actual loads can vary from the forecast because economic conditions may be different from those forecast and load center temperatures may differ from the normalized temperatures on which the forecast is based.

Risk in the growth rate is modeled with a triangular risk distribution defined by a high value, a low value, and a most likely value, or mode. The most likely value is the forecast rate of year-to-year load growth. The high value is an optimistic load growth rate that serves as the 80th percentile of the triangular distribution, and the low value is a pessimistic load growth rate that serves as the 20th percentile of the distribution.

The optimistic load growth rate is determined by adding the predicted year-to-year NT load growth rate to an optimistic forecast of Gross Domestic Product (GDP) obtained from IHS Markit (formally known as Global Insights), an economic forecasting and analysis firm. Similarly, the pessimistic load growth rate is determined by adding the predicted year-to-year NT load growth rate to a pessimistic GDP forecast obtained from IHS Markit. The resulting distribution around growth rate serves as the first component of NT revenue risk.

The impact of temperature variability on the load is also modeled. The load forecast is based on normalized temperature, so the risk arises from the variability of load center temperatures. Variability in these temperatures induces variability in the load. The distribution of temperatures in a 30-year period follows a normal distribution (a bell curve symmetrical around the mean) calculated from historical temperatures.

The NT revenue risk distributions have standard deviations of $2.4 million for FY 2018 and $3.2 million for FY 2019.

5.1.1.2 Long-Term Network Point-to-Point Service Revenue Risk

Risks in revenue from long-term PTP service are related to assumptions about new service and potential deferrals of the service commencement date, exercise of renewals under BPA's Open Access Transmission Tariff (OATT), conversions of Formula Power Transmission (FPT) and

Integration of Resources (IR) service to PTP service, and possible customer default. BPA also models revenue risk related to service that has not been granted yet but that might be granted during the rate period.

BPA models risk for forecast revenue from new transmission service (that is, service that has been offered to customers but has not yet begun) because the customer has a right to defer the service commencement date for up to five years. A deferral delays the revenue from that service for the period of the deferral. The revenue risk associated with deferrals is based on a comparison of the service commencement date on the service reservation to the probable service commencement date after deferrals.

BPA identifies possible deferrals by determining whether the service appears to be related to a Large Generator Interconnection Agreement (LGIA). If the generation in-service date has been forecast, then risk around the forecast LGIA generation in-service date is modeled using a triangular distribution defined by maximum, most likely, and minimum values. The transmission service commencement date is assumed to match the risk-adjusted generation in-service date (that is, the analysis assumes the customer would defer its transmission service commencement date to match the generation in-service date). If the generation in-service date has not been forecast, the risk of deferral is identified based on information from BPA's account executive for the customer. The likelihood of deferral is based on the account executive's level of confidence that the request will begin on its current service commencement date.

BPA also models risk associated with revenue from new service to be offered as a result of new transmission infrastructure that BPA will energize in the rate period. A PERT distribution (a distribution in which the user defines the maximum, most likely, and minimum values) is used to model possible delays to the in-service date for these projects (and resulting delays in the start of service and receipt of revenue). There are no sales associated with new infrastructure that BPA will energize in the BP-18 rate period.

Risk is also modeled for service that is eligible to be renewed during the rate period. Historical data was gathered on the frequency of renewal of long-term PTP service for service reservations that have been eligible for renewal over the past five years. A normal distribution was identified using the historical frequency of renewals for service requests that are eligible for renewal. That distribution is applied to the service requests that are eligible for renewal during the rate period to identify the probability of the service being renewed.

Risk is modeled for service that is eligible to convert from FPT or IR service to PTP service by gathering information from BPA's account executives for the customers on the likelihood that individual requests will convert either after the expiration or prior to the expiration of the FPT or IR contract. The likelihood of conversion is based on the account executive's level of confidence that the request will be converted to PTP service during the rate period.

Risk of default is modeled for all current and anticipated service. The probability of default for each customer is modeled using information from Standard & Poor's. BPA applies Standard & Poor's credit rating for each entity and refers to Standard & Poor's Global Corporate Average Default Rate for the level of default risk associated with that credit rating. Standard & Poor's conducts its default studies on the basis of groupings called static pools. Static pools are formed by grouping issuers by rating category at the beginning of each year covered by the study. Annual default rates were calculated for each static pool, first in units and later as percentages with respect to the number of issuers in each rating category. Finally, these percentages were combined to obtain cumulative default rates for the 30 years covered by the study. If a default occurs in the model, the capacity held by the defaulting customer is assumed to return to inventory and be resold for a portion of the remaining months of the fiscal year. Assuming the capacity is resold for only a portion of the year accounts for the time it takes to process and offer the new contract for the service.

Risk associated with additional sales of service that have not yet been requested (the possibility that revenues will be higher than forecast due to these sales) is modeled based on three different sources: (1) new sales associated with new generation that is included in the LGIA forecast but for which long-term service has not yet been requested; (2) new sales from transmission inventory that becomes available due to customer default, as described above; and (3) new sales as a result of competitions performed in accordance with section 17.7 of the OATT (deferral competitions). Sales due to new generation are modeled using a PERT distribution and information from TS's customer service engineering organization on expected in-service dates. Modeling of sales from inventory that becomes available due to customer default is described above. To model sales that occur after competitions, it is assumed that zero to six competitions will be performed a year. For each competition performed there is a 50 percent chance that the competition will be successful and result in additional revenue.

The long-term PTP revenue risk distribution results in standard deviations of $10.5 million for FY 2018 and $17.3 million for FY 2019.

5.1.1.3 Short-Term Network Point-to-Point Service Revenue Risk

The short-term PTP revenue forecast carries significant risk due to the nature of the product. This service is not reserved far in advance with an existing contract but instead is requested on an hourly, daily, weekly, or monthly basis. Short-term PTP service is sensitive to market conditions and streamflow, so we model the risks around the price spread between the North of Path 15 (NP-15) hub and the Mid-C hub, as well as streamflow. Modeling of risk around the

Mid-C and NP-15 prices incorporates variability around natural gas prices and streamflow. Natural gas volatility is important because natural gas-fired electricity generation is often the marginal resource in western power markets and therefore plays an important role in setting the market price of power. Fluctuations in natural gas prices lead to fluctuations in power prices.

Streamflow variability is important for two reasons. First, the Mid-C and NP-15 price spread is positively correlated with streamflow. As streamflow increases, Mid-C prices decrease and the price spread widens. Second, streamflow has a high correlation with short-term transmission reservations made by PS. The short-term PTP forecast is developed using a regression analysis, so risk of errors is incorporated in the relationships identified between historical sales, streamflow, and price spread. For a more in-depth discussion on the short-term PTP forecast and risk assessment process, *see* the Transmission Rates Study and Documentation, BP-18-E-BPA-08, section 2.2.2.2. The short-term PTP risk distribution resulting from the methodology outlined above results in standard deviations of $8.7 million for FY 2018 and $8.7 million for FY 2019.

5.1.1.4 Long-Term Southern Intertie Service Revenue Risk

Long-term capacity on the Southern Intertie is almost fully subscribed in the north to south direction. This means that BPA cannot make additional sales unless existing agreements terminate or are not renewed, or until reliability upgrades on the Pacific DC Intertie (PDCI) increase transfer capability. In addition, there is a queue of transmission service requests that are seeking long-term IS service but that have not been granted service because no long-term IS capacity is available for sale. Requests in the queue are expected to replace any contracts that expire. Thus, BPA identified a high service commencement probability, with a normal distribution, for these requests. In addition, default risk for service on the Southern Intertie is modeled using the same method described for long-term PTP service. The long-term IS risk distribution results in standard deviations of $1.5 million for FY 2018 and $1.8 million for FY 2019.

5.1.1.4.1 Short-Term Southern Intertie Service Revenue Risk

The revenue forecast for short-term Southern Intertie service carries significant risk due to the nature of the product. This service is not reserved far in advance with an existing contract but instead is requested on an hourly, daily, weekly, or monthly basis. Short-term Southern Intertie service is sensitive to market conditions and streamflow, so BPA models the risks around the NP-15 minus Mid-C price spread, South of Path 15 (SP-15) minus Mid-C spread, and streamflow. The forecast is developed using a regression analysis, so BPA also models risk of errors in correlations identified between historical sales, streamflow, and price spread. For a more in-depth discussion on the short-term IS forecast and risk assessment process, *see id.* § 2.3.1.2. The short-term IS revenue risk distribution results in standard deviations of $0.6 million for FY 2018 and $0.5 million for FY 2019.

5.1.1.5 Other Transmission Revenue Risk

The risk related to other transmission revenues arises from variability in Utility Delivery and DSI Delivery revenues, revenues from fiber and wireless contracts, and revenues from other fixed-price contracts. This risk is modeled based on the historical variance between rate case revenue forecasts for these products and actual revenue. Data from FY 2011 through FY 2015 is used and the mean average deviation is applied, resulting in a deviation of $0.2 million per year for Utility and DSI Delivery revenue, $0.9 million per year for fiber and wireless contract revenue, and $1.8 million per year for other fixed-price contract revenue.

5.1.1.6 Ancillary and Control Area Services Revenue Risk

BPA models the revenue risk associated with the ancillary service Scheduling, System Control, and Dispatch, which applies to customers taking both firm and non-firm transmission service. SCD revenue is based on sales of NT, long-term PTP, short-term PTP, long-term IS, and short-term IS. As such, the revenue variability for SCD follows the risk associated with those services, and SCD revenue risk is not modeled individually. Instead, variations in SCD revenues are assumed to be directly proportional to variations in the revenue from those services.

BPA does not model revenue risk associated with the Ancillary Service Reactive Supply and Voltage Control from Generation Sources (GSR), because that rate is a formula rate that is currently set at zero. As a result, it generates no revenue. The formula rate for GSR is calculated for each quarter but has been calculated to be zero in every quarter since 2009.

Generation Inputs services comprise Regulation & Frequency Response, Dispatchable Energy Resource Balancing Service, Variable Energy Resource Balancing Service, Energy & Generation Imbalance, and Operating Reserve – Spinning & Supplemental (OR). We sorted these sources of revenue into two categories based on their characteristics and their impact on TS net revenue: (1) variable revenue but fixed expense, and (2) variable revenue with variable expense.

TS expects to pay PS a fixed amount for RFR, VERBS, and DERBS during the rate period. The revenue that TS charges to its customers is variable, however, so the contribution to TS net revenue is variable. For RFR the billing factor is customers' loads in the BPA balancing area, which vary due to factors that include weather variation from normal and changes in economic conditions. The standard deviation of historical billed RFR loads from FY 2008 through FY 2014 is used in the simulation of the load and associated revenue during the rate period. The resulting variability on revenues for RFR is $0.1 million per year. The VERBS billing factor is the installed capacity of the plant for specified schedule elections. In the BP-18 rate period 2,607 MW of wind installed capacity is expected to leave the BPA balancing authority area, and 300 MW of new wind generation is expected to be connected to the BPA balancing authority area. Any departure from the forecast time period when generation leaves or interconnects to the BPA balancing authority presents variability to VERBS revenues. The resulting variability on revenues for VERBS is $0.3 million per year.

The DERBS billing factor is based on the station control error of non-Federal thermal plants. Station control error is the deviation of a generator from its basepoint, which is the generation level to which the plant is planned to operate. The historical standard deviation of the station control area for DERBS plants for *inc* and *dec* reserves is used in simulating DERBS revenue. The resulting variability on revenues for DERBS is $0.1 million per year.

Generation inputs whose revenues and expenses have generally equivalent variability and are correlated—that is, any potential change in TS revenue is matched by an offsetting change in TS expense—also create insignificant uncertainty in TS net revenue. This category comprises EI/GI and OR. No uncertainty in revenue from EI/GI and OR is modeled.

5.1.1.7 Total Transmission Revenue Risk

The Transmission Revenue Risk worksheets compute the revenue risk and the resulting expected value for transmission revenues from these products. The revenue uncertainty from all transmission services is aggregated. The variability of the total transmission revenues (as measured by the standard deviation) is less than the sum of the variabilities (standard deviations) of the individual services. The standard deviation of the distribution of total transmission revenue for the FY 2018 is $17.2 million and for FY 2019 is $24.5 million. In each game, the total transmission revenue is linked into the income statement in T-NORM.

5.1.2 T-NORM Inputs

5.1.2.1 Inputs to T-NORM

To obtain the data used to develop the probability distributions used by T-NORM, BPA analyzed historical data and consulted with subject matter experts for their assessment of the risks concerning their cost estimates, including the possible range of outcomes and the associated probabilities of occurrence.

Table 7 shows the 5th percentile, mean, and 95th percentile results from each of the risk models described below, along with the deterministic amount that is assumed in the revenue requirement for that risk. *See* Transmission Revenue Requirement Study Documentation, BP-18-E-BPA-09A, Table 1-1.

5.1.2.1.1 Transmission Operations

T-NORM models variability in transmission operations expense using PERT distributions for FY 2017 and for each of the two fiscal years in the rate period, FY 2018 and FY 2019. For FY 2017, the most likely value comes from the start-of-year budget. For the rate period years, the most likely values come from the revenue requirement. The minimum and maximum values of the distribution come from the historically observed minimum and maximum actual values (FY 2009–2016) compared to rate case projections. The minimum value is 8.4 percent lower and the maximum value is 15.9 percent higher than the expected level of expense in the revenue requirement.

See Table 7 for the expected, 5th percentile, and 95th percentile values for this risk.

5.1.2.1.2 Transmission Maintenance

To model variability in transmission maintenance expense, PERT distributions are used for FY 2017 and for each of the two fiscal years in the rate period. For FY 2017, the most likely value comes from the start-of-year budget. For the rate period years, the most likely values come from the revenue requirement. The minimum and maximum values of the distribution come from the historically observed minimum and maximum actual values (FY 2009–2016) compared to rate case projections. The minimum value is 9.7 percent lower and the maximum value is 27.1 percent higher than the expected level of expense in the revenue requirement.

See Table 7 for the expected, 5th percentile, and 95th percentile values for this risk.

5.1.2.1.3 Agency Services General & Administrative

To model variability in agency services general and administrative (G&A) costs, PERT distributions are used for FY 2017 and for each of the two fiscal years in the rate period. For FY 2017, the most likely value comes from the start-of-year budget. For the rate period years, the most likely values come from the revenue requirement. The minimum and maximum values come from the historically observed minimum and maximum actual values (FY 2009–2016) compared to rate case projections. The minimum value is 22.9 percent lower and the maximum value is 14.8 percent higher than the expected level of expense in the revenue requirement.

See Table 7 for the expected, 5th percentile, and 95th percentile values for this risk.

5.1.2.1.4 Interest on Long-Term Debt Issued to the U.S. Treasury

T-NORM models the impact of interest rate uncertainty associated with new debt issuances (borrowings) on interest expense and on TS Reserves. For FYs 2017, 2018, and 2019 the amounts of planned new borrowing are $473 million, $482 million, and $509 million respectively. These planned borrowings (Transmission Revenue Requirement Study Documentation, BP-18-E-BPA-09A, Tables 8-2 and 10-2) are used to calculate expected interest expense on long-term debt and appropriations for the revenue requirement. This analysis assesses the potential difference in interest expense on long-term debt and appropriations from the amount rates are set to recover in the revenue requirement. The method used for modeling interest rate uncertainty in T-NORM is identical to the method used in P-NORM. This method is described in section 4.1.2.1.8.

See Table 7 for the expected, 5th percentile, and 95th percentile values for this risk.

5.1.2.1.5 Transmission Engineering

To model variability in transmission engineering expense, PERT distributions are used for FY 2017 and for each of the two fiscal years in the rate period. For FY 2017, the most likely value comes from the start-of-year budget. For the rate period years, the most likely values come from the revenue requirement. The minimum and maximum values of the distribution come from the historically observed minimum and maximum actual values (FY 2009–2016) compared to rate case projections. The minimum value is 28.1 percent lower and the maximum value is 30.0 percent higher than the expected level of expense in the revenue requirement.

See Table 7 for the expected, 5th percentile, and 95th percentile values for this risk.

5.1.2.2 T-NORM Results

The output of T-NORM is an Excel® file containing (1) the aggregate total net revenue deltas for all of the individual risks that are modeled and (2) the associated NRTC adjustments for each game for FY 2017, FY 2018, and FY 2019. Each run has 3,200 games. The ToolKit uses this file in its calculations of TPP. Summary statistics and distributions for each fiscal year are shown in Documentation Figure 25.

5.1.3 Net Revenue-to-Cash Adjustment

One of the inputs to the ToolKit (through T-NORM) is the NRTC Adjustment. Most of BPA's probabilistic modeling is based on impacts of various factors on net revenue. BPA's TPP standard is a measure of the probability of having enough cash to make payments to the Treasury. While cash flow and net revenue generally track each other closely, there can be significant differences in any year. For instance, the requirement to repay Federal borrowing over time is reflected in the accrual arena as depreciation of assets. Depreciation is an expense that reduces net revenue, but there is no cash inflow or outflow associated with depreciation. The same repayment requirement is reflected in the cash arena as cash payments to the Treasury to reduce the principal balance on Federal bonds and appropriations. These cash payments are not reflected on income statements. Therefore, in translating a net revenue result to a cash flow result, the impact of depreciation must be removed and the impact of cash principal payments must be added. The 3,200 NRTC adjustments calculated in T-NORM make the necessary changes to convert RevRAM and T-NORM accrual results (net revenue results) into the equivalent cash flows so ToolKit can calculate reserves values in each game and thus calculate TPP.

The NRTC Adjustment is modeled probabilistically in T-NORM. As its starting point, T-NORM uses deterministic expected values for each fiscal year's cash adjustment and non-cash adjustment. It then adjusts NRTC results using the cash timing lag model described below. The NRTC table is shown in Documentation Table 23.

5.1.3.1 Cash Timing Lags

T-NORM uses projections of revenues and expenses to estimate possible changes in TS reserves. TS reserves are discussed in section 5.2.1.1.1 below. A projected revenue or expense is an assumption of when accounting will record that a service has been performed by BPA (revenue) or that a service has been received by BPA (expense). The projection of when accounting records a revenue or expense is typically within one month of when the cash is received or paid. For most revenues and expenses, BPA assumes that cash is received or paid in the same year as the revenue or expense is recorded, unless the revenue or expense has no cash associated with it (that is, it is a non-cash revenue or non-cash expense). These known non-cash revenues and non-cash expenses are removed from the forecast. As revenues and expenses are projected for each game in T-NORM, uncertainty in the timing of when the cash will be received or paid is modeled.

For revenues or expenses projected to be recorded by accounting near the end of a fiscal year, there is a potential for the cash transaction to lag sufficiently far behind the accounting transaction that the cash will be received or paid in the following year. If some cash receipts from revenue lag into the next year, TS reserves at the end of the year will be lower than indicated by accrual accounting records, and if some cash payments for recorded expenses lag into the next year, TS reserves at the end of the year will be higher than indicated by accrual accounting records. Timing differences of this kind can be observed in historical data by looking at the year-over-year changes to the accounts payable, accounts receivable, materials, and prepaid expense accounts. These accounts represent revenues or expenses BPA has recorded from an accounting standpoint but for which BPA has not yet received or paid cash.

To model this uncertainty required examination of the changes in BPA's accounts payable (both Power and Transmission), accounts receivable, materials, and prepaid expenses from FY 2009 to

FY 2014. BPA assumed that the percentage of each account that is attributed to Transmission Services equaled the percentage of BPA's total revenues that is earned by Transmission Services. Transmission revenue was 29 percent of total FCRPS revenue in every year of the historical period except one, when it was 28 percent. Thus, BPA assumed that 29 percent of these accounts was attributable to Transmission Services in all years but one, and 28 percent in the other year. For FY 2009 to FY 2014 the changes in accounts payable, accounts receivable, materials and prepaid expenses attributed to Transmission Services were –$32.1 million, $14.9 million, –$18.5 million, $7.4 million, $10.3 million, and $8.2 million respectively. The average over the period was –$5 million and the standard deviation was $18.3 million. Over many years the average will be very close to $0, because the changes to these accounts are merely timing differences between when revenue and expenses are accounted for and when the cash is received or paid. The historical data show that over time, increases in one year are offset by decreases in another.

For example, in FY 2014, the change in accounts payable, accounts receivable, materials, and prepaid expenses was $8.2 million; in FY 2013 it was –$10.3 million; and the trend continues through FY 2009. BPA modeled the variability in cash timing lags in T-NORM in FY 2017–2019 with a normal distribution (bell-shaped curve), average of $0 (theoretical long-run average), and standard deviation of $18.3 million (observed standard deviation). Thus, on average, the cash timing lag will be $0, but it has the potential to vary on either side of $0. Two-thirds of the time the cash lag will be within the range of positive and negative $18.3 million. Because the FY 2016 actual amount was positive, the Study assumes the FY 2017 amount will be negative, the FY 2018 amount will be positive, and the FY 2019 amount will be negative, reflecting the offsetting relationship of these amounts year over year. Each T-NORM game sampled three values from the earlier-described normal distribution for FY 2017, FY 2018, and FY 2019 and converted the sampled value to the appropriate positive or negative sign if it did not show the appropriate sign already. The analysis resulted in an average cash lag in FY 2018 and FY 2019 of $0.8 thousand, with a standard deviation of $11.0 million.

5.2 Transmission Quantitative Risk Mitigation

The preceding sections of this chapter describe the risks that are modeled explicitly, with the output of T-NORM and RevRAM quantitatively portraying the financial uncertainty faced by TS in each fiscal year. This section describes the tools used to mitigate these risks—TS Reserves, PNRR, CRAC, and RDC—and how BPA evaluates the adequacy of this mitigation.

The risk that is the primary subject of this Study is the possibility that BPA might not have sufficient cash on September 30, the last day of its fiscal year, to fully meet its obligation to the U.S. Treasury for that fiscal year. BPA's TPP standard, described in section 2.3 above, defines a way to measure this risk (TPP) and a standard that reflects BPA's tolerance for this risk (no more than a five percent probability of any deferrals of BPA's Treasury payment in a two-year rate period). TPP and the ability of the rates to meet the TPP standard are measured in the ToolKit by applying the risk mitigation tools described in this chapter to the modeled financial risks described in the previous chapters.

A second risk addressed in this Study is within-year liquidity risk—the risk that at some time within a fiscal year BPA will not have sufficient cash to meet its immediate financial obligations (whether to the Treasury or to other creditors) even if BPA might have enough cash later that year. In each recent rate proceeding, a need for reserves for within-year liquidity ("liquidity reserves") has been defined. This level is based on a determination of BPA's total need for liquidity and a subsequent determination of how much of that need is properly attributed to Transmission Services.

5.2.1 Transmission Risk Mitigation Tools

5.2.1.1 Liquidity

Cash and cash equivalents provide liquidity, which means they are available to meet immediate and short-term obligations. For the BP-18 rate period, Transmission Services has one source of liquidity: Financial Reserves Available for Risk Attributed to TS (TS Reserves). Liquidity mitigates financial risk by serving as a temporary source of cash for meeting financial obligations during years in which net revenue and the corresponding cash flow are lower than anticipated. In years of above-expected net revenue and cash flow, financial reserves can be replenished so they will be available in later years.

5.2.1.1.1 TS Reserves

TS Reserves are not held in a TS-specific account. BPA has only one account, the BPA Fund, in which it maintains financial reserves. Staff in the Chief Financial Officer's (CFO's) organization "attributes" part of the BPA Fund balance to the Transmission generation function and part to the transmission function. Reserves attributed to Transmission do not belong to Transmission Services; they belong to BPA.

Financial reserves available to the transmission function (Transmission Services) include cash and investments ("Treasury Specials") held in the BPA Fund at the Treasury plus any deferred borrowing. Deferred borrowing refers to amounts of capital expenditures BPA has made that authorize borrowing from the Treasury when BPA has not yet completed the borrowing. Deferred borrowing amounts can be converted to cash at any time by completing the borrowing.

Some financial reserves are considered to be not available for risk; such encumbered reserves are not considered in the risk analysis. Encumbered reserves include customer deposits for capital projects related to Large or Small Generator Interconnection Agreements, Network Open

Season, the Southern Intertie capital program, and Master Lease funds. These encumbered reserves are deposits from third parties to pay for specific facilities, security deposits from third parties, or advances through BPA's Master Lease program that are required by the lease agreement terms to be used only for specified projects. Encumbered reserves attributed to TS equaled $72.8 million at the start of FY 2017. Financial reserves available for risk attributed to TS (TS Reserves) were $443.8 million at the beginning of FY 2017.

5.2.1.1.2 Within-Year Liquidity Need

The within-year liquidity need is the amount of cash or other liquidity (the temporary availability of cash) BPA needs at the beginning of a fiscal year for dealing with cash flow deficits that result from payments being made before cash receipts. T-NORM records a Treasury payment miss (that is, T-NORM assumes that BPA is unable to make its Treasury payment) if TS reserves in a game are below the within-year liquidity need at the end of either year in the rate period. The transmission business line has over $900 million in annual expenses.

Transmission's within-year liquidity need was calculated to be $100 million in the BP-16 rate proceeding, based on an analysis of historical within-year cash flow variation. *See* BP-16 Transmission Revenue Requirement Study Documentation, BP-16-FS-BPA-08A, § 10.6. Transmission's within-year liquidity need remains unchanged for this study.

5.2.1.2 Planned Net Revenues for Risk

Analyses of BPA's TPP are conducted during rate development using current projections of TS reserves. If the TPP is below the 95 percent two-year standard established in BPA's Financial Plan, then the projected reserves, along with whatever other risk mitigation is considered in the risk study, are not sufficient to reach the TPP standard. This may be corrected by adding PNRR to the revenue requirement as a cost needing to be recovered by rates. This addition has the effect of increasing rates, which will increase net cash flow, which will increase the available TS reserves and therefore increase TPP. No PNRR is needed to meet the TPP standard for the BP-18 rates, so PNRR is $0 for both FY 2018 and FY 2019.

PNRR is calculated in the ToolKit, described in section 3.1.5 above. If the ToolKit calculates TPP below 95 percent, PNRR can be iteratively added to the model in one or both years of the rate period (typically, PNRR is evenly added to both years). PNRR is added in $1 million increments until a 95 percent TPP is achieved. The calculated PNRR amounts are then provided to the Transmission Revenue Requirement Study (BP-18-E-BPA-09), which calculates a new revenue requirement. This adjusted revenue requirement is then iterated through the rate models and tested again in ToolKit. If ToolKit reports TPP below 95 percent or TPP above 95 percent by more than the equivalent of $1 million in PNRR, PNRR adjustments are calculated again and reiterated through the rate models.

5.2.1.3 The Cost Recovery Adjustment Clause

As specified in the Financial Reserves Policy (*see* Chapter 6), the BP-18 Initial Proposal includes a CRAC and an RDC for Transmission. This is the first time that these rate adjustment mechanisms have been included in Transmission rates. The CRAC can be used to adjust rates upward to respond to the financial circumstances BPA experiences before the next opportunity to adjust rates in a rate proceeding. The Transmission CRAC could increase rates for FY 2018 based on financial results for FY 2017. It also could increase rates for FY 2019 based on the accumulation of financial results for FY 2017 and FY 2018 (taking into account any Transmission CRAC applying to FY 2018 rates). The Transmission rates subject to the Transmission CRAC (and eligible for the Transmission RDC; *see* § 5.2.1.4 below) are the Network Integration Rate (NT-18), the Point-to-Point Rate (PTP-18), the Formula Power Transmission Rate (FPT-18.1), the Southern Intertie Point-to-Point Rate (IS-18), the Utility

Delivery Rate (Transmission GRSP II.A.1.b.), the Scheduling, Control, and Dispatch Rate (ACS-18), the Integration of Resources Rate (IR-18), and the Montana Intertie Rate (IM-18). *See* Transmission GRSP II.H.

5.2.1.3.1 Calibrated Net Revenue

Calibrated Net Revenue (CNR) is Net Revenue adjusted for certain debt management and contract-related transactions that affect the relationship between accruals and cash. The method for calculating Transmission CNR is described in Transmission GRSP II.H. Examples of the application of this method, including actions that change Federal depreciation, debt transactions that affect net revenue but not cash, and cash contract settlements, are described in Documentation Appendix A.

5.2.1.3.2 Description of the Transmission CRAC

As described in the introduction to section 5.2 above and Transmission GRSP II.H, the CRAC for FY 2018 and FY 2019 is an annual upward adjustment in various Transmission rates. The threshold for triggering the CRAC is an amount of Transmission Services' CNR accumulated since the end of FY 2016.

The Accumulated Calibrated Net Revenue (ACNR) threshold values will be set in July 2017, based on the terms specified in the Financial Reserves Policy. *See* Chapter 6. In this Initial Proposal, the ACNR threshold is set at the equivalent of $99 million in TS Net Reserves, consistent with the Financial Reserves Policy. *Id.* The ACNR threshold for each year is calculated by taking the difference between average ACNR and average Net Reserves across all 3,200 games in the ToolKit and adding that difference to the target Transmission CRAC threshold in terms of reserves.

As an example, assume that a given fiscal year's Transmission CRAC threshold in terms of reserves is supposed to be $100 million. If the average ACNR at the start of that fiscal year is $200 million and the average Net Reserves at the start of that fiscal year is $50 million, then the CRAC threshold in terms of ACNR for that year is $150 million ($100 million + $200 million – $50 million = $250 million).

The Transmission CRAC will recover 100 percent of the amount that ACNR is below the threshold, up to a cap of $100 million. The Transmission CRAC will be implemented only if the amount of the CRAC is greater than or equal to $5 million.

Calculations for the CRAC that could apply to FY 2018 rates will be made in July 2017; the corresponding calculations for possible adjustments to FY 2019 rates will be made in September 2018. A forecast of the year-end Transmission Services ACNR will be made based on the results of the Third Quarter Review and then compared to the thresholds for the CRAC and the RDC. *See* § 5.2.1.4 below. If the ACNR forecast is below the CRAC threshold, an upward rate adjustment will be calculated for the duration of the upcoming fiscal year. *See* Transmission GRSP II.H.

5.2.1.4 Reserves Distribution Clause

One of BPA's financial policy objectives is to ensure that reserves do not accumulate to excessive levels. *See* § 2.1 above. The Transmission RDC is triggered if both BPA ACNR and Transmission Services' ACNR are above a threshold. The RCD provides a downward adjustment to the same Transmission rates that are subject to the Transmission CRAC. In the same way that a CRAC passes costs of bad financial outcomes to BPA's customers, an RDC passes benefits of good financial outcomes to BPA's customers. The total distribution is capped at $200 million per fiscal year. The RDC will be implemented only if the amount of the RDC is greater than or equal to $5 million. *See* Chapter 6 and Transmission GRSP II.I.

5.2.2 ToolKit

The ToolKit model is described in section 3.1.5, above. The inputs to the ToolKit for Transmission are shown in Documentation Figure 26.

5.2.2.1 ToolKit Inputs and Assumptions for Transmission

5.2.2.1.1 RevRAM Results

The ToolKit reads in risk distributions generated by RevRAM that are created for the current year, FY 2017, and the rate period, FY 2018–2019. TPP is measured for only the two-year rate period, but the starting Reserves Available for Risk for FY 2018 depend on events yet to unfold in FY 2017; these runs reflect that FY 2017 uncertainty. See section 5.1.1 for more detail on RevRAM.

5.2.2.1.2 Non-Operating Risk Model

The ToolKit reads in T-NORM distributions that are created for FY 2017–2019 and reflect the uncertainty around non-operating expenses. See section 5.1.2 for more detail on T-NORM.

5.2.2.1.3 Treatment of Treasury Deferrals

In the event that ToolKit forecasts a deferral of payment of principal to the Treasury, the ToolKit assumes that BPA will track the balance of payments that have been deferred and will repay this balance to the Treasury at its first opportunity. "First opportunity" is defined for TPP calculations as the first time Transmission Services ends a fiscal year with more than $100 million in net reserves. The same applies to subsequent fiscal years if the repayment cannot be completed in the first year after the deferral. This is referred to as “hybrid” logic on the ToolKit main page.

5.2.2.1.4 Starting TS Reserves

The FY 2017 starting TS reserves have a known value of $443.8 million based upon the FY 2016 Fourth Quarter Review. Each of the 3,200 games starts with this value. See section 5.2.1.1.1 above for a description of TS reserves.

5.2.2.1.5 Starting ACNR

The FY 2017 starting ACNR value of $0 million is known from the definition of ANCR as being accumulated TS net revenue since the end of FY 2016. Each of the 3,200 games starts with this value.

5.2.2.1.6 TS Liquidity Reserves Level

The TS Liquidity Reserves Level is an amount of TS reserves set aside (*i.e.*, not available for TPP use) to provide liquidity for within-year cash flow needs. This amount is set to $100 million. *See* § 5.2.1.1.2.

5.2.2.1.7 Interest Rate Earned on Reserves

Interest earned on the cash component and the Treasury Specials component of TS reserves and interest paid on the Treasury Facility is assumed to be 0.32 percent in FY 2017, 0.62 percent in FY 2018, and 0.84 percent in FY 2019.

5.2.2.1.8 Interest Credit Assumed in Net Revenue

An important feature of the ToolKit is the ability to calculate interest earned on TS reserves separately for each game. The net revenue games the ToolKit reads in from T-NORM include deterministic assumptions of interest earned on reserves for each fiscal year; that is, the interest earned does not vary from game to game. To capture the risk impacts of variability in interest earned induced by variability in the level of reserves, in the TPP calculations the values embedded in the T-NORM results for interest earned on reserves are backed out of all ToolKit games and replaced with game-specific calculations of interest credit. The interest credit assumptions embedded in T-NORM results that are backed out are $3.9 million for FY 2017, $4.5 million for FY 2018, and $5.4 million for FY 2019.

5.2.2.1.9 The Cash Timing Adjustment

The cash timing adjustment reflects the impact on earned interest of the non-linear shape of TS reserves throughout a fiscal year as well as the interest earned on reserves attributed to TS that are not available for risk and not modeled in the ToolKit. The ToolKit calculates interest earned on reserves by making the simplifying assumption that reserves change linearly from the beginning of the year to the end. It takes the average of the starting reserves and the ending reserves and multiplies that figure by the interest rate for that year. Because TS cash payments to the Treasury are not evenly spread throughout the year but instead are heaviest in September, TS will typically earn more interest in BPA's monthly calculations than the straight-line method yields. Additionally, the ToolKit does not model Reserves Not For Risk (*see* § 5.2.1.1.1) or the interest earned from these. The cash timing adjustment is a number from the repayment study that approximates this additional interest credit earned on reserves throughout the fiscal year along with the interest earned on reserves attributed to TS that are not available for risk. The cash timing adjustments for this study are $4.3 million for FY 2017, $2.3 million for FY 2018, and $2.1 million for FY 2019.

5.2.2.1.10 Cash Lag for PNRR

Although figures for cash lag for PNRR appear in the inputs section of the ToolKit's main page, they are calculated automatically. When the ToolKit calculates a change in PNRR (either a decrease, or more typically, an increase), it calculates how much of the cash generated by the increased rates would be received in the subsequent year, because September revenue is not received until October. In order to treat ToolKit-generated changes in the level of PNRR on the same basis as amounts of PNRR that have already been assumed in previous iterations of rate calculations and are already embedded in the RevSim results, the ToolKit calculates the same kind of lag for PNRR that is embedded in the RevSim output file the ToolKit reads. Because this study does not require PNRR, there are no cash adjustments for PNRR.

5.2.3 Quantitative Risk Mitigation Results

Summary statistics are shown in Table 8.

5.2.3.1 Ending TS Reserves

Known starting TS Reserves for FY 2017 are $443.8 million. The expected values of ending net reserves are $351 million for FY 2017, $346 million for FY 2018, and $297 million for FY 2019. Over 3,200 games, the range of ending FY 2019 net reserves is from $95 million to $635 million. The rate adjustment mechanisms would produce a CRAC of $5 million for FY 2020 in the game with the lowest resulting net reserves if the FY 2020 rates include mechanisms comparable to those included in the FY 2018–2019 rates. In the game with the highest resulting net reserves, an RDC of $200 million would occur (if Agency ANR is also high enough) for FY 2020 if the FY 2020 rates include mechanisms comparable to those included in the FY 2018–2019 rates. The 50 percent confidence interval for ending net reserves for FY 2019 is $217 million to $328 million. ToolKit summary statistics for reserves and liquidity are in Documentation Figure 27 and Table 24.

5.2.3.2 TPP

The two-year TPP is over 99.9 percent. In 3,200 games, there are no deferrals for FY 2017, FY 2018, or FY 2019.

5.2.3.3 CRAC and RDC

The Transmission CRAC does not trigger in any of the 3,200 games.

At the end of FY 2017, the Transmission RDC triggers less than 0.1 percent of the time (3 of the 3,200 games), yielding an expected value of $0.04 million in distributions for FY 2018. When a Transmission RDC occurs, the forecast average size of the distributions in FY 2018 is $41.9 million. For the end of FY 2018, Transmission RDC triggers 3.6 percent of the time (114 of the 3,200 games), yielding an expected value of $2.5 million in distributions in that year. When a Transmission RDC occurs, the forecast average size of the distributions in FY 2019 is $70 million. CRAC and Transmission RDC statistics are shown in Table 8.

The thresholds and caps for the Transmission CRAC and Transmission RDC applicable to rates for FY 2018 and FY 2019 are shown in Tables 9 and 10. The BPA RDC Thresholds are shown in Table 6.

6. FINANCIAL RESERVES POLICY IMPLEMENTATION

6.1 Overview of Financial Reserves Policy

BPA's Financial Reserves Policy (Policy) establishes a method for determining a target level of financial reserves for Power Services, Transmission Services, and BPA as a whole. The Financial Reserves Policy applies a consistent methodology to determine the lower financial reserves threshold and upper financial reserves threshold for each business line and upper financial reserves thresholds for BPA as a whole. The lower and upper thresholds are used to determine when certain rate mechanisms are triggered within a rate period to support the policy objectives stated in the Policy. The Policy's main components are as follows:

- Financial reserves targets for Power Services and Transmission Services are calculated independently for each rate period based on the higher of what is necessary to meet the 95 percent Treasury Payment Probability (TPP) Standard or 90 days' cash on hand (a common industry liquidity metric). *See* Harris *et al.,* BP-18-E-BPA-17, Appendix A, §§ 3.1–3.2.
- A lower financial reserves threshold is calculated independently for Power Services and Transmission Services on a rate period basis, based on the financial reserves equivalent of 30 days' cash on hand below the financial reserves target. For each business line, if financial reserves fall below the lower threshold, a CRAC specific to that business line shall trigger to recover the amount of the shortfall the following fiscal year. *Id.* § 3.3. Lower thresholds are also called CRAC thresholds.
- An upper financial reserves threshold is calculated independently for Power Services and Transmission Services on a rate period basis, based on the financial reserves equivalent of 30 days' cash on hand above the financial reserves target. As specified by the Policy, the agency upper threshold is the sum of the business line upper thresholds. If one business line's financial reserves and agency financial reserves both are above their

respective upper thresholds, an RDC shall trigger for that business line, and the above-threshold financial reserves will be considered for investment in other high-value purposes such as debt retirement, incremental capital investment, or rate reduction. *Id.* § 3.4. Upper thresholds are also called RDC thresholds.

The Policy includes a "phase-in" of the lower threshold over a period of 10 years. *Id.* § 4.2. Implementation of the phase-in for this rate period is described in section 6.8 below.

6.2 Power Services Financial Reserves Target and Upper and Lower Thresholds

The Financial Reserves Target and Upper and Lower Thresholds for Power called for by the Policy are based on 90, 120, and 60 days' cash respectively. The calculations of Power operating expenses and translations into days' cash dollar amounts are shown in Table 11.

6.3 Transmission Services Financial Reserves Target and Upper and Lower Thresholds

The Financial Reserves Target and Upper and Lower Thresholds for Transmission called for by the Policy also are based on 90, 120, and 60 days' cash. The calculations of Transmission operating expenses and translations into days' cash dollar amounts are shown in Table 12.

6.4 Agency Upper Threshold

The Agency (BPA) Upper Financial Reserves Threshold called for by the Policy is the sum of the Power and Transmission Upper Reserves Thresholds. The Agency Upper Financial Reserves Threshold is used for each of the two years of the BP-18 rate period.

The formula for the Agency Financial Reserves Upper Threshold and the calculation of that threshold for BP-18 are as follows:

BPA Upper Financial Reserves Threshold = Power Upper Financial Reserves Threshold + Transmission Upper Financial Reserves Threshold

BPA Upper Threshold = $618 million + $198 million = $816 million.

6.5 Reconciling Financial Reserves Policy and TPP Perspectives on CRAC Thresholds

BPA's Financial Reserves Policy and BPA's TPP framework (*see* § 2.3) both provide guidance on the proper level of CRAC thresholds. These perspectives will be reconciled by establishing tentative thresholds as the Policy requires and then evaluating whether the tentative values are high enough to satisfy the requirements of BPA's TPP standard. The CRAC Thresholds, measured in reserves for risk, are in whole numbers of millions of dollars.

6.5.1 Power CRAC Thresholds

The tentative Power CRAC Threshold derived as the Policy requires is $309 million. However, this amount is reduced to the level of the Power CRAC Threshold from the BP-16 Final Proposal, $0, as part of the phase-in of the Policy (*see* § 6.8 below). Power TPP is above 95 percent with that threshold. Because the TPP framework does not call for a higher threshold than the Policy, the tentative threshold of $0 becomes the Power CRAC Threshold for FY 2018 and FY 2019 in the BP-18 Initial Proposal. This figure may be modified by the Power CRAC Threshold modification process in July 2017.

6.5.2 Transmission CRAC Thresholds

The tentative Transmission CRAC Threshold derived as the Policy requires is $99 million. Transmission TPP is above 95 percent with that threshold. Because the TPP framework does not call for a higher threshold than the Policy, the tentative threshold of $99 million becomes the Transmission CRAC Threshold for FY 2018 and FY 2019 in the BP-18 Initial Proposal.

6.6 ACNR Values for CRAC and RDC Thresholds

The CRAC and RDC thresholds determined above have been translated into equivalent ACNR values for use in calculations of whether the CRAC or RDC for Power or Transmission will trigger. *See* Mandell *et al.*, BP-18-E-BPA-15, § 2. Output from the ToolKit was used to determine the ACNR thresholds for the CRACs and RDCs. Toolkit simultaneously calculates reserves and ACNR levels for each game. This data is used to identify the ACNR level that is equivalent to the reserves-based threshold.

The Power and Transmission CRAC thresholds are shown in Tables 4 and 9, respectively. The Power, Transmission, and BPA RDC thresholds are shown in Tables 5, 10, and 6, respectively.

6.7 Timing of the CRAC and RDC Calculations

Calculations to determine if the FY 2018 Power CRAC, Power RDC, Transmission CRAC, and Transmission RDC trigger will be made in July 2017. The data used in the calculations will be based on the FY 2017 3rd Quarter Review, updated with any significant changes available since that review.

Calculations to determine if the FY 2019 Power CRAC, Power RDC, Transmission CRAC, and Transmission RDC trigger will be made in September 2018. The data used in the calculations will be based on the FY 2018 3rd Quarter Review, updated with any significant changes available since that review.

6.8 Phase-in of the Power CRAC Threshold in July 2017

At the time the CRAC and RDC calculations for application to FY 2018 are made (July 2017), the following formula will phase in the long-term CRAC Threshold as Measured in Power Reserves for Risk goal as specified in the proposed Financial Reserves Policy.

In July 2017, the CRAC Threshold as Measured in Power Reserves for Risk for rates in both FY 2018 and FY 2019 will be modified. The thresholds for the two years will be the same. The Modified CRAC Threshold as Measured in Power Reserves for Risk (P_Res_Mod) will be increased to the highest whole million dollar amount not exceeding $300 million such that:

$$Incremental\ CRAC \leq maximum(0, IRPL - BRC - CRAC\_SQ)$$

Where:

Incremental CRAC is the amount of incremental rate pressure, as a percentage, that an increase in the CRAC Threshold as Measured in Power Reserves for Risk will add to the Non-Slice Tier 1 rate in the first year of the rate period.

IRPL, Incremental Rate Pressure Limiter, is a percentage determined by the Administrator as part of a limit on the rate impact that may be caused by the phasing in of the higher CRAC Threshold as Measured in Power Reserves for Risk called for by the Policy. This value is equal to 3 percent.

BRC, Base Rate Change, is the percentage change in the average Non-Slice Tier 1 rate from BP-16 to BP-18.

CRAC_SQ, Status Quo CRAC, is the Power CRAC percentage change to the FY 2018 average Non-Slice Tier 1 rate that would result from calculating the Power CRAC assuming the Modified CRAC Threshold as Measured in Power Reserves for Risk for FY 2018 is equal to that of the previous rate period. The

Modified CRAC Threshold as Measured in Power Reserves for Risk in the previous rate period, BP-16, was \$0.

After the CRAC Threshold as Measured in Power Reserves has been modified, the Power CRAC Thresholds Measured in ACNR applicable to FY 2018 and FY 2019 will be modified as follows:

$$P\_ACNR_{2018}Mod = \$X + (P\_Res\_Mod - \$0)$$

$$P\_ACNR_{2019}Mod = \$Y + (P\_Res\_Mod - \$0)$$

Where:

$P\_ACNR_{2018}Mod$, *2018 Modified Power CRAC Threshold Measured in ACNR,* is the Power CRAC Threshold Measured in ACNR, as modified by the above procedure, that will be used in July 2017 for calculating the Power CRAC applicable to rates for FY 2018.

P_Res_Mod, *Modified CRAC Threshold as Measured in Power Reserves for Risk,* is the CRAC Threshold as Measured in Power Reserves for Risk for both FY 2018 and FY 2019 as modified by the above procedure.

$P\_ACNR_{2019}Mod$, *2019 Modified Power CRAC Threshold Measured in ACNR,* is the Power CRAC Threshold Measured in ACNR, as modified by the above procedure, that will be used in September 2018 for calculating the Power CRAC applicable to rates for FY 2019.

TABLES AND FIGURES

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Table 1: RevSim Net Revenue Statistics (With PNRR of $0 million) for FY 2018 and FY 2019

	FY18	FY19
Average	$ (51,157)	$ 112,397
Median	$ (52,718)	$ 114,279
Standard Deviation	$ 160,459	$ 170,603
1%	$ (329,982)	$ (413,138)
2.50%	$ (319,940)	$ (377,229)
5%	$ (310,568)	$ (333,618)
10%	$ (280,860)	$ (278,069)
15%	$ (240,158)	$ (243,723)
20%	$ (196,565)	$ (211,083)
25%	$ (166,614)	$ (185,601)
30%	$ (144,279)	$ (164,440)
35%	$ (119,043)	$ (141,965)
40%	$ (95,284)	$ (123,147)
45%	$ (74,944)	$ (104,710)
50%	$ (52,718)	$ (84,235)
55%	$ (31,746)	$ (65,277)
60%	$ (5,518)	$ (46,198)
65%	$ 12,972	$ (25,925)
70%	$ 38,554	$ (3,913)
75%	$ 63,687	$ 20,934
80%	$ 86,829	$ 46,559
85%	$ 114,564	$ 74,433
90%	$ 157,691	$ 107,328
95%	$ 219,923	$ 156,216
97.50%	$ 261,078	$ 199,103
99%	$ 328,587	$ 242,160

Table 2: P-NORM Risk Summary

	A	B	C	D	E	F	G
	P-NORM Risk Summary ($000,000)						
	Study Section	**Risk Title**	**Fiscal Year**	**Pro Forma / Rev. Req.**	**5th Percentile**	**Mean**	**95th Percentile**
1	4.1.2.1.1	CGS Operations and Maintenance	2017	319.1	316.4	318.9	321.3
2			2018	270.2	263.1	271.0	279.5
3			2019	339.9	331.1	341.0	351.9
4	4.1.2.1.2	U.S. Army Corps of Engineers and Bureau of Reclamation O&M	2017	408.6	408.6	409.5	413.6
5			2018	420.1	420.1	421.9	426.1
6			2019	418.1	418.1	419.8	424.1
7	4.1.2.1.3	Conservation Expense	2017	76.3	74.1	76.0	77.6
8			2018	71.8	67.7	71.2	74.2
9			2019	71.8	67.7	71.2	74.2
10	4.1.2.1.4	Spokane Settlement	2017	22.2	22.2	22.2	22.2
11			2018	22.6	22.6	23.2	28.3
12			2019	23.0	23.0	24.1	28.7
13	4.1.2.1.5	Power Services Transmission Acquisition and Ancillary Services	2017	91.8	91.3	91.8	92.2
14			2018	91.9	89.9	91.6	93.2
15			2019	92.4	90.3	92.3	94.2
16	4.1.2.1.6	Power Services Internal Operations Expenses	2017	147.7	147.7	147.7	147.7
17			2018	154.9	154.9	154.9	154.9
18			2019	159.0	159.0	159.0	159.0
19	4.1.2.1.7	Fish & Wildlife Expenses	2017	306.9	296.9	299.9	303.2
20			2018	310.5	297.5	301.9	306.3
21			2019	310.5	297.5	301.9	306.3
22	4.1.2.1.8	Interest Expense Risk	2017	382.5	383.6	384.4	385.4
23			2018	815.6	815.8	817.5	819.6
24			2019	585.2	583.9	586.0	588.5
25	4.1.2.1.9	CGS Refueling Outage Risk	2017	N/A	-5.7	0.1	4.4
26			2018	N/A	0.0	0.0	0.0
27			2019	N/A	-5.7	0.0	4.2
34	4.1.2.1.12	Undistributed Reduction Risk	2017	0.0	0.0	0.0	0.0
35			2018	0.0	0.0	0.0	0.0
36			2019	0.0	0.0	0.0	0.0

Table 3: Power Risk Mitigation Summary Statistics
[Dollars in millions]

	A	B	C	D
1	Two-Year TPP		99.9%	
		FY 2017	**FY 2018**	**FY 2019**
2	PNRR	$0.0	$0.0	$0.0
3	CRAC Frequency	0%	35%	37%
4	Expected Value CRAC Revenue		$31	$38
5	RDC Frequency	0%	0%	0.1%
6	Expected Value RDC Payout	$0	$0	$0
7	Treasury Deferral Frequency	0%	0%	0.1%
8	Expected Value Treasury Deferral	$0	$0	$0
9	Exp. Value End-of-Year Net Reserves	$53	$72	$106
10	Net Reserves, 5th percentile	($198)	($244)	($289)
11	Net Reserves, 25th percentile	($48)	($76)	($86)
12	Net Reserves, 50th percentile	$53	$62	$97
13	Net Reserves, 75th percentile	$159	$205	$279
14	Net Reserves, 95th percentile	$294	$418	$540

Table 4: Power CRAC Annual Thresholds and Caps
[Dollars in millions]

ACNR Calculated Near End of Fiscal Year	***CRAC Applied to Fiscal Year***	***Threshold Measured in ACNR*****	***Threshold Measured in Reserves for Risk*****	***Maximum CRAC Amount (Cap)****
2017	2018	$209.8	$0	$300
2018	2019	$172.5	$0	$300

* The Maximum CRAC Recovery Amount (Cap) may be modified by the NFB Adjustment (if triggered).

** The Thresholds will be modified in July 2017 as described in Power GRSP II.O

Table 5: Power RDC Thresholds and Caps

[Dollars in millions]

ACNR Calculated Near End of Fiscal Year	*RDC Applied to Fiscal Year*	*Threshold Measured in Power ACNR*	*Threshold Measured in Power Reserves for Risk*	*Maximum RDC Amount (Cap)*
2017	2018	$827.8	$618	$500
2018	2019	$790.5	$618	$500

Table 6: BPA RDC Annual Threshold

[Dollars in millions]

ACNR Calculated Near End of Fiscal Year	*RDC Applied to Fiscal Year*	*Threshold Measured in BPA ACNR*	*Threshold Measured in BPA Reserves for Risk*
2017	2018	$696.4	$816
2018	2019	$681.4	$816

Table 7: T-NORM Risk Summary

	A	B	C	D	E	F	G
	T-NORM Risk Summary ($000,000)						
	Study Section	**Risk Title**	**Fiscal Year**	**Pro Forma / Rev. Req.**	**5th Percentile**	**Mean**	**95th Percentile**
1	5.1.3.1.1	Transmission Operations	2017	167.5	158.1	169.6	182.8
2			2018	173.6	163.8	175.8	189.5
3			2019	170.9	161.3	173.0	186.5
4	5.1.3.1.2	Transmission Maintenance	2017	169.8	158.4	174.7	195.0
5			2018	176.9	165.0	182.0	203.1
6			2019	178.4	166.4	183.5	204.8
7	5.1.3.1.3	Agency Services General & Administrative	2017	90.7	78.2	89.2	99.0
8			2018	98.5	85.0	96.9	107.5
9			2019	100.6	86.8	99.0	109.8
10	5.1.3.1.4	Interest on Long-Term Debt Issued to the U.S. Treasury	2017	145.6	147.2	148.5	150.0
11			2018	103.3	105.3	108.3	111.9
12			2019	109.6	108.4	114.4	121.2
13	5.1.3.1.5	Transmission Engineering	2017	57.9	47.7	58.1	68.6
14			2018	58.7	48.4	58.9	69.5
15			2019	59.5	49.0	59.7	70.5

Table 8: Transmission Risk Mitigation Summary Statistics
[Dollars in millions]

	A	B	C	D
1	Two-Year TPP		99.99%	
		FY 2017	FY 2018	FY 2019
2	PNRR	$0.0	$0.0	$0.0
3	CRAC Frequency	0%	0%	0%
4	Expected Value CRAC Revenue	$0	$0	$0
5	RDC Frequency	0%	0.1%	3.6%
6	Expected Value RDC Payout	$0	$0.04	$2.5
7	Treasury Deferral Frequency	0%	0%	0%
8	Expected Value Treasury Deferral	$0	$0	$0
9	Exp. Value End-of-Year Net Reserves	$352	$346	$299
10	Net Reserves, 5th percentile	$287	$218	$218
11	Net Reserves, 25th percentile	$322	$266	$266
12	Net Reserves, 50th percentile	$346	$297	$297
13	Net Reserves, 75th percentile	$369	$328	$328
14	Net Reserves, 95th percentile	$405	$380	$380

Table 9: Transmission CRAC Annual Thresholds and Caps
[Dollars in millions]

ACNR Calculated Near End of Fiscal Year	*CRAC Applied to Fiscal Year*	*Threshold Measured in ACNR*	*Threshold Measured in Reserves for Risk*	*Maximum CRAC Amount (Cap)*
2017	2018	($230.4)	$99	$100
2018	2019	($208.1)	$99	$100

Table 10: Transmission RDC Thresholds and Caps
[Dollars in millions]

ACNR Calculated Near End of Fiscal Year	RDC Applied to Fiscal Year	Threshold Measured in ACNR	Threshold Measured in Reserves for Risk	Maximum RDC Amount (Cap)
2017	2018	($131.4)	$198	$200
2018	2019	($109.1)	$198	$200

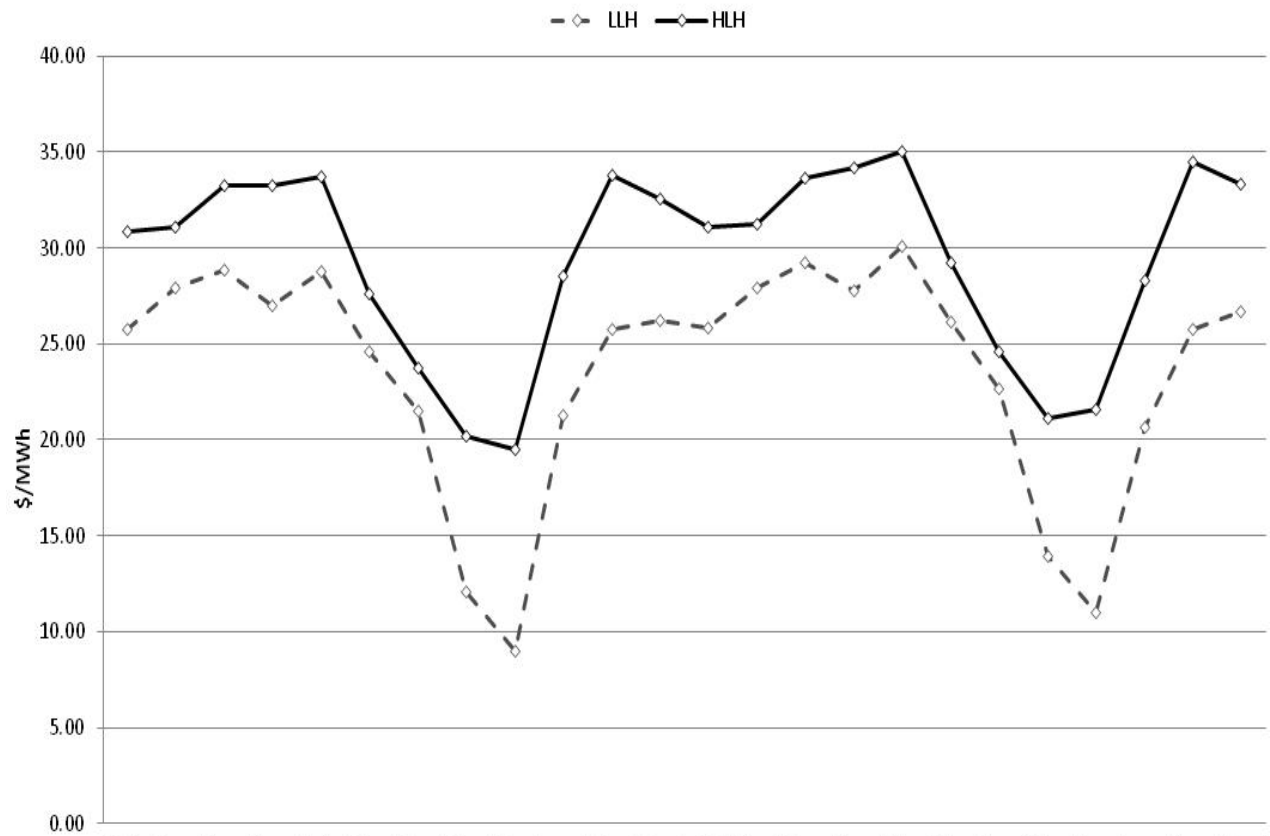
Table 11: Power Days' Cash and Financial Reserves Thresholds

		a	b
1		2018	2019
2	TOTAL EXPENSES	$2,941m	$2,796m
3	less		
4	NET INTEREST EXPENSE	$125m	$132m
5	DEPRECIATION	$143m	$143m
6	AMORTIZATION	$89m	$89m
7	NON-FEDERAL DEBT SERVICE	$646m	$410m
8	POWER PURCHASES	$99m	$99m
9	sum of rows 4-8	$1,102m	$873m
10	OPERATING EXPENSES (row 2 less row 9)	$1,839m	$1,923m
11	Operating Expenses divided by 365 (row 10/365)	$5m	$5m
12	rate period average (average of row 11 column A and B)	$5m	
13	Target Financial Reserves (row 12 value * 90)	$464m	$464m
14	30 days cash on hand (row 12 * 30)	$155m	$155m
15	Lower Financial Reserves Threshold (row 13 less row 14))	$309m	$309m
16	Upper Financial Reserves Threshold (row 13 plus row 14))	$618m	$618m

Table 12: Transmission Days' Cash and Financial Reserves Thresholds

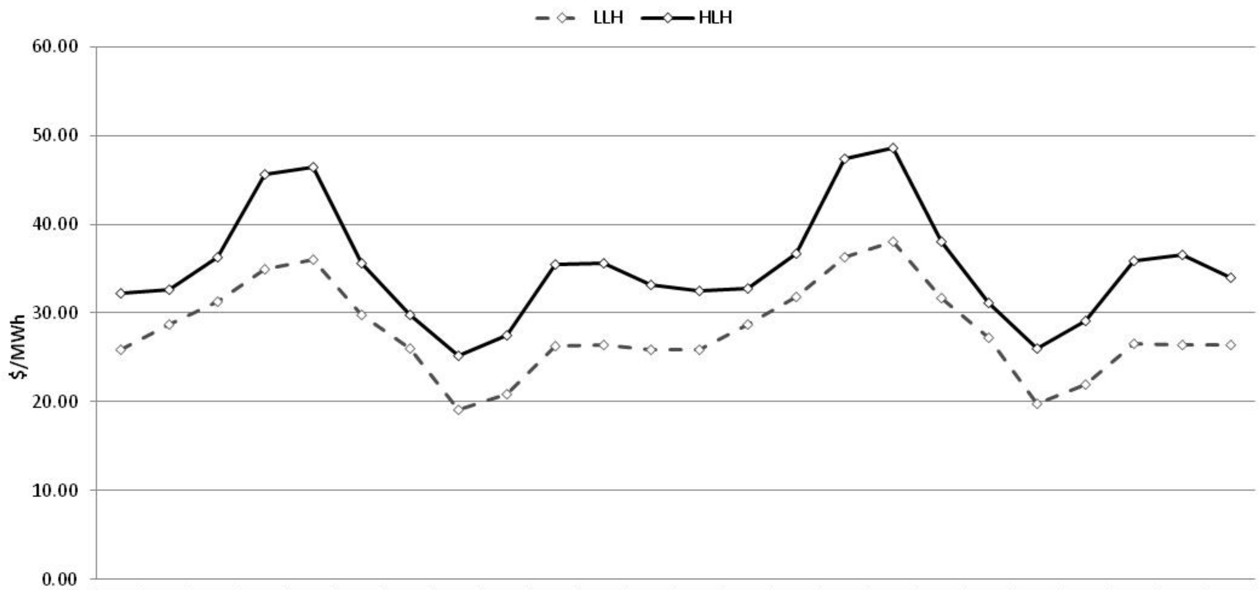
		a	b
1		2018	2019
2	TOTAL EXPENSES	$1,015m	$1,041m
3	less		
4	NET INTEREST EXPENSE	$145m	$158m
5	DEPRECIATION & AMORTIZATION	$269m	$281m
6	NON-FEDERAL DEBT SERVICE	$0m	$0m
7	POWER PURCHASES	$0m	$0m
8	sum of rows 4-7	$414m	$439m
9	OPERATING EXPENSES (row 2 less row 8)	$601m	$602m
10	Operating Expenses divided by 365 (row 9/365)	$1.6m	$1.6m
11	rate period average (average of row 10 column A and B)	$1.6m	
12	90 days cash on hand target financial reserves (row 11 column A * 90)	$148m	$148m
13	30 days cash on hand (row 11 column A * 30)	$49m	$49m
14	Lower Financial Reserves Threshold (row 12 less row 13)	$99m	$99m
15	Upper Financial Reserves Threshold (row 12 plus row 13)	$198m	$198m

Figure 1: Monthly Average Mid-C Prices for Market Price Run for FY 2018 and FY 2019



	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19
LLH	25.73	27.90	28.86	26.99	28.77	24.56	21.52	12.08	9.02	21.25	25.77	26.25	25.80	27.92	29.21	27.75	30.05	26.17	22.64	13.90	11.01	20.67	25.76	26.71
HLH	30.88	31.11	33.22	33.25	33.70	27.64	23.72	20.18	19.48	28.54	33.79	32.58	31.07	31.21	33.65	34.18	35.00	29.22	24.56	21.15	21.61	28.28	34.51	33.35

Figure 2: Monthly Average Mid-C Prices for Critical Water Run for FY 2018 and FY 2019



	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19
LLH	25.85	28.75	31.33	34.90	36.00	29.75	26.04	19.07	20.82	26.28	26.36	25.89	25.86	28.73	31.83	36.33	38.06	31.71	27.16	19.74	21.88	26.61	26.36	26.42
HLH	32.25	32.67	36.25	45.66	46.43	35.67	29.74	25.17	27.45	35.46	35.66	33.21	32.56	32.76	36.74	47.42	48.55	38.06	31.14	25.98	29.08	35.94	36.55	34.05

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BONNEVILLE POWER ADMINISTRATION
November 2016