Attachment 3:

Proposed Changes to Power and Transmission Risk Study, BP-20-E-BPA-05

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BP-20 Rate Proceeding

Initial Proposal

Power and Transmission Risk Study

BP-20-E-BPA-05

January 2019

POWER AND TRANSMISSION RISK STUDY
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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Bps	basis points
Btu	British thermal unit
CIP	Capital Improvement Plan
CIR	Capital Investment Review
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COB	California-Oregon border
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
CWIP	Construction Work in Progress
CY	calendar year (January through December)
DD	Dividend Distribution
DDC	Dividend Distribution Clause
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

EIM	Energy imbalance market
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
FERC	Federal Energy Regulatory Commission
FOIA	Freedom Of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FRP	Financial Reserves Policy
F&W	Fish & Wildlife
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
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
IRPL	Incremental Rate Pressure Limiter
IS	Southern Intertie
kcfs	thousand cubic feet per second
kW	kilowatt
kWh	kilowatthour
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)

LPP	Large Project Program
LTF	Long-term Firm
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenue
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	**N**ational Marine Fisheries Service (NMFS) **F**ederal Columbia River Power System (FCRPS) **B**iological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (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
NRU	Northwest Requirements Utilities
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
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

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
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
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 Service
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
VER	Variable Energy Resource
VERBS	Variable Energy Resource 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

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1. INTRODUCTION

BPA's business environment is replete with uncertainty that a rigorous ratemaking process must consider. The objectives of the Power and Transmission Risk Study (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 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: (1) a risk assessment step, in which the distributions (or profiles) of operating and non-operating risks are defined; and (2) a risk mitigation step, in which risk mitigation tools are assessed with respect to their ability to recover costs given the uncertainties assessed in step 1. The risk assessment estimates two elements: 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 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 risk that financial reserves and other liquidity may be insufficient to repay the Treasury, this Study also describes the implementation of BPA's Financial Reserves Policy (FRP), which was established in the Administrator's Record of Decision for BP-18 and refined in September 2018. *See* Appendix A (FRP); *see also,* Administrator's Final Record of Decision, BP-18-A-04; Administrator's Record of Decision, Financial Reserves Policy Phase-In Implementation (Sept. 2018) (*available at* https://www.bpa.gov/Finance/FinancialPublicProcesses/Financial-Reserves-Leverage/Pages/Financial-Reserves-Leverage-Policies.aspx). The FRP was established in order to maintain BPA's financial health. It establishes financial reserves target ranges for the business lines and agency, as well as rate actions to be taken when financial reserves are outside those target ranges.

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 the TPP Standard.
- 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).
- Implement BPA's Financial Reserves Policy in order to maintain prudent financial reserves levels and support BPA's financial objectives.
- Include in the risk mitigation package only those elements that can be relied upon.
- 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 calculation takes into account the thresholds and caps for the risk adjustment mechanisms, that is, the Cost Recovery Adjustment Clause (CRAC), the Reserves Distribution Clause (RDC), and the Financial Reserves Policy Surcharge (FRP Surcharge). These thresholds and caps are incorporated in the Power and Transmission General Rate Schedule Provisions (GRSPs) and will be used in later calculations outside the ratemaking process to determine whether a CRAC, RDC, or FRP Surcharge will be applied to certain power and transmission rates for FY 2020 or FY 2021. Power Rate Schedules and General Rate Schedule Provisions, BP-20-E-BPA-10-CC01 (Power GRSPs); Transmission, Ancillary, and Control Area Service Rate Schedules and GRSPs, BP-20-E-BPA-11-CC01 (Transmission GRSPs).

2.3 Financial Reserves and Liquidity

This Study evaluates the availability of financial reserves to meet BPA's obligations over the rate period when taking into account rates and risk mitigation tools. When this Study uses the term "financial reserves," it is referring to a specific subset of total financial reserves, known as "financial reserves available for risk," which consist of cash and investments held in the Bonneville Fund, *plus* any deferred borrowing, *less* any financial reserves not available for risk, *less* any outstanding balance on the Treasury Facility. These components are discussed below.

- Deferred borrowing consists of 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.
- Reserves not available for risk consist of funds held for specific purposes, such as deposits from customers and other entities.
- The Treasury Facility is an agreement between BPA and the US Treasury that makes a $750 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. The

Treasury Facility allows BPA to borrow to meet cash needs. Because of this, financial reserves could fall to a negative level, and BPA could still meet its cash obligations. Borrowing from the Treasury Facility generates cash, but also results in an outstanding balance against the Treasury Facility. When borrowing occurs, the effect on financial reserves is neutral; financial reserves are augmented by the cash but reduced by the outstanding balance. As the cash is expended, however, this relationship allows financial reserves to go negative.

This Study also differentiates between financial reserves attributable to Power Services (PS reserves) and financial reserves attributable to Transmission Services (TS reserves). Financial reserves are not held in PS- or TS-specific accounts. 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 "attribute" part of the Bonneville Fund balance to the power generation function and part to the transmission function. These funds do not belong to Power Services or Transmission Services; they belong to BPA.

2.4 BPA's Treasury Payment Probability (TPP) Standard

In the WP-93 rate proceeding, BPA adopted and implemented its 10-Year Financial Plan, which included a policy requiring that BPA set rates to achieve a high probability of meeting its payment obligations to the U.S. Treasury (Treasury). 1993 Final Rate Proposal Administrator's Record of Decision (ROD), WP-93-A-02, at 72. The specific standard set in the 10-Year Financial Plan was a 95 percent probability of making both of the annual Treasury payments in the two-year rate period on time and in full. This TPP standard was established as a rate period standard; that is, it focuses upon the probability that BPA can successfully make all of its payments to Treasury over the multi-year rate period rather than the probability for a single year. The TPP standard remains in effect in the most recent release of the Financial Plan, dated

February 2018. *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 Power Services (PS) and Transmission Services (TS). 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 Financial Reserves.* The amount of PS reserves and TS reserves at the start of FY 2019.
- *Planned Net Revenues for Risk (PNRR).* PNRR is the final component of the revenue requirement that may be added to annual expenses. PNRR may be added when the risk mitigation provided by starting financial reserves and other risk mitigation tools is insufficient to meet the TPP standard. PNRR may also be added in order to meet the needs of the FRP.
- *BPA's Treasury Facility.* For BP-20, the full $750 million in the Treasury Facility is considered to be available for the liquidity needs associated with PS; TS reserves are sufficient for the liquidity needed to mitigate TS financial risk.

- *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-20 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-18 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 December following a fiscal year in which PS or TS Accumulated Calibrated Net Revenue (~~ANR~~ACNR) falls below the Power or Transmission CRAC threshold. For the Initial Proposal, the PS threshold is set at the ~~ANR~~ ACNR equivalent of $0 in PS reserves in accordance with the FRP. Power GRSP II.O. The TS threshold is set at the ~~ANR~~ACNR equivalent of $0 in TS reserves in accordance with the FRP. Transmission GRSP II.G.
- *Reserves Distribution Clause.* The RDC allows the Administrator to repurpose financial reserves (that are above the level necessary for TPP and the FRP) as debt reduction, incremental capital investment, rate reduction through a Dividend Distribution (DD), distribution to customers, or any other business-line-specific purpose determined by the

Administrator. A DD is a downward adjustment to the applicable power or transmission rates. The adjustment is applied to rates charged for service beginning in December following a fiscal year in which PS or TS ~~ANR~~ACNR is above the RDC threshold. A financial reserves distribution may be made if (1) financial reserves attributed to a business line exceed the RDC threshold for that business line, and (2) BPA financial reserves exceed the BPA RDC threshold. Power GRSP II.P; Transmission GRSP II.H.

- *FRP Surcharge.* The FRP Surcharge is an upward adjustment to applicable power and transmission rates. The adjustment is applied to rates charged for service beginning in December following a fiscal year in which PS or TS ~~ANR~~ACNR falls below the business line lower threshold. For the Initial Proposal, the PS lower threshold is set at the ~~ANR~~ACNR equivalent of $300 million in PS reserves, in accordance with the FRP. The TS lower threshold is set at the ~~ANR~~ACNR equivalent of $94 million in TS reserves, in accordance with the FRP.

2.5 BPA's Financial Reserves Policy (FRP)

The FRP applies a consistent methodology to determine lower and upper financial reserves thresholds for each business line and an upper financial reserves threshold for BPA as a whole. *See* Appendix A (FRP). The FRP describes the actions BPA may take in response to financial reserves levels that either fall below a lower threshold or exceed an upper threshold. Relevant to this Study, the FRP is implemented through the CRAC, RDC, and FRP Surcharge rate mechanisms for PS and TS. This is described further in Sections 4.2 and 5.2.

The FRP was adopted in the BP-18 rate proceeding. Administrator's Final Record of Decision, BP-18-A-04, Appendix A. In 2018, BPA refined the FRP to specify the rate actions that would be taken when financial reserves attributable to a business line are below its lower threshold. Administrator's Record of Decision, Financial Reserves Policy Phase-In Implementation

(Sept. 2018) (*available at* https://www.bpa.gov/Finance/FinancialPublicProcesses/Financial-Reserves-Leverage/Pages/Financial-Reserves-Leverage-Policies.aspx.

2.6 Quantitative vs. 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 and financial reserves) for each of the two years in the rate period (FY 2020–2021) and for the year preceding the rate period (FY 2019). 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 CRACs and FRP Surcharges for Power and Transmission to manage financial risk. The CRACs and FRP Surcharges add additional risk mitigation to that provided by financial reserves and liquidity. When financial reserves plus the additional revenue earned through a business line's CRAC and FRP Surcharge 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 financial 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 qualitative risks usually fit into one of two general categories that make them unsuitable for quantitative 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.

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* §§ 2.4, 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 AURORA®, the Revenue Simulation Model (RevSim), the Non-Operating Risk Models (P-NORM and T-NORM), and ToolKit each run 3,200 iterations, or games. AURORA® estimates electricity prices, which serve as inputs to numerous other studies, including the Power portions of this Study. RevSim (see Section 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-20 rate period, FY 2020 and FY 2021. 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 Revenue Requirement Study Documentation, BP-20-E-BPA 09A, Table 13-2. 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 (RAM2020). 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 AURORA®. *See* Power Market Price Study and Documentation, BP-20-FS-BPA-04, § 2.3. RevSim also uses deterministic monthly load and resource data; revenues, expenses, and rates from RAM2020; and non-varying revenues and expenses from the Power Revenue Requirement Study, BP-20-E-BPA-02, and Section 2 of the Power Rates Study, BP-20-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 AURORA®. Where applicable, the results for that game also serve as input to RevSim. The prices from AURORA®, combined with the deterministic and variable values used in RevSim, constitute one net revenue game. Not every risk model will generate 3,200 games, and where necessary, a bootstrap approach (*i.e.,* resampling with replacement) is used to produce a full distribution of 3,200 games. Each of the 3,200 games in the joint distribution is uniquely identified, which allows for coordination between AURORA® prices and RevSim inventory levels.

Expenses associated with system augmentation purchases are estimated in RevSim using variable electricity prices calculated under 1937 "critical water" conditions. These results are used by RAM2020 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 RAM2020 when calculating rates and calculating net revenues provided for input into the ToolKit model.

The monthly flat electricity prices calculated by AURORA® under 80 water year conditions for all 3,200 games for each fiscal year are inputs into the risk model that calculates the average 4(h)(10)(C) credits included in the Power Revenue Requirement Study, BP-20-E-BPA-02. The 4(h)(10)(C) credits calculated by this 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-20-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 games 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 and incorporates the risk of Legacy Products (Formula Power Transmission) conversion.
- 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.
- 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.

The transmission products and services that are modeled for revenue uncertainty are individually modeled in Microsoft Excel®. A separate spreadsheet tab in RevRAM adds all individual revenue products to generate the total Transmission revenue forecast (excluding reimbursable revenues).

3.1.3 Non-Operating Risk Models

A Non-Operating Risk Model (NORM) is an analytical risk tool that quantifies the impacts of risks that are not modeled in the revenue simulation models (Section 3.1.2). Two NORMs are used in BP-20: P-NORM, which contains models of non-operating risks for PS; and T-NORM, which contains models of non-operating risks for TS. The NORMs follow BPA's traditional approach to modeling risks, which uses Monte Carlo simulation. In this technique, a model runs through a number of games (also known as 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 P-NORM or T-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 (NRTC) Adjustments

One of the inputs to the ToolKit (through P-NORM and 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. P-NORM and T-NORM each 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 financial reserves values in each game and thus calculate TPP.

The NRTC Adjustment is modeled probabilistically in P-NORM and T-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, 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 of Ithaca, New York. @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 and TS to meet BPA's TPP standard given the net revenue and financial reserve 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 Financial Reserves and CRAC and RDC settings) defined within the ToolKit file itself. The ToolKit reads in data from three external files. For Power, ToolKit reads in a file from RevSim and two files from P-NORM. For Transmission, ToolKit reads in a file from RevRAM and two files 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 financial reserves and liquidity attributable to each business line, and thus on TPP. The ToolKit registers a Treasury payment deferral when financial reserves and all sources of liquidity for a business line 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 for each business line 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 or several risk mitigation tools may be adjusted in the ToolKit until the standard is met. These options include (1) adding PNRR to the revenue requirement; (2) raising the CRAC and FRP Surcharge thresholds, which makes them more likely to trigger; and (3) increasing the cap on the annual revenue the CRAC can collect.

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 values from a wide variety of risk distributions.

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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 (Corps), and U.S. Bureau of Reclamation (Reclamation) 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 2019 and FY 2021.

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 (RAM2020). RevSim also determines, by simulation, PS operating net revenue risk for use in the ToolKit Model. *See* § 3.1.5.

4.1.1.1 Inputs to RevSim

Inputs to RevSim include risk data simulated by various risk models and market prices calculated by AURORA®. *See* Power Market Price Study, BP-20-E-BPA-04, § 2.1, regarding AURORA®. 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 Heavy Load Hour (HLH) and Light Load Hour (LLH) load and resource data are provided by the Power Loads and Resources Study, BP-20-E-BPA-03. A summary of these load and resource data in the form of monthly surplus/deficit energy for FY 2020–2021 is provided in the Power Loads and Resources Study Documentation, BP-20-E-BPA-03A, Table 10.1.1.

4.1.1.1.3 Miscellaneous Revenues

Miscellaneous revenues represent estimated revenues that are not subject to change through BPA's ratemaking process. See Power Rates Study, BP-20-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 RAM2020. 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 RAM2020 are input into RevSim to facilitate the calculation of changes in Load Shaping revenue. Demand billing determinants and rates from RAM2020 are input into RevSim to facilitate the calculation of changes in Demand revenue. *See* Power Rates Study Documentation, BP-20-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 2020–2021, 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. *See* Power Loads and Resources Study, BP-20-E-BPA-03, § 3.1.2.1.2.

For each of the 80 water years, monthly 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-20-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 the Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Table 1 for FY 2020 and Table 2 for FY 2021. Monthly values for Federal hydro HLH generation ratios for each of the 80 historical water years are provided in *id.*, Table 3 for FY 2020 and Table 4 for FY 2021.

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 *id.*, Tables 5–7 for FY 2020 and Tables 8–10 for FY 2021. These generation data are added to the values presented in *id.*, 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 2020–2021). 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 4.1.1.1.5.5 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 AURORA® and RevSim. See Power Market Price Study and Documentation, BP-20-E-BPA-04, Section 2.3.3.1, regarding the development of water year sequences for PNW hydro generation. BP-20 also incorporates updated spill operations, as detailed in the Power Loads and Resources Study, BP-20-E-BPA-03, Section 3.1.2.1, and the Power and Transmission Rate Policy Testimony, BP-20-E-BPA-19, Section 5.

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 WECC. *See* Power Market Price Study and Documentation, BP-20-E-BPA-04, § 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 AURORA®, 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 AURORA®, which simulates these data when calculating electricity prices. See *id.* at Section 2.3.6.1 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-20-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-20-E-BPA-03, Section 3.1.3.

The simulated monthly wind generation results are specified in terms of flat energy. Results shown in Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Figure 1 are the monthly flat energy output for all wind projects during FY 2020–2021 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-20-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 Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Tables 11–12 report information from which the value of wind generation during FY 2020–2021 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, 5th, 50th, and 95th percentile electricity prices estimated by AURORA® 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 $108 million during FY 2020 and $103 million during FY 2021. *See* Power Revenue Requirement Study Documentation, BP-20-E-BPA-02A, Table 3A, line 100. 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 Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Figures 2 and 3 indicate how FY 2020–2021 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 $71.0 million in FY 2020 and $65.6 million in FY 2021, 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 that PS has under contract on the Southern (AC and DC) Interties.

Results shown in Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Figures 4 and 5 reflect the probability distributions for transmission and ancillary service expenses during FY 2020–2021. 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 system-wide fish and wildlife mitigation activities to various purposes. 16 U.S.C. § 839b(h)(10)(C). 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 2020–2021 by first summing the costs of the operating impacts on the hydro system (*e.g.*, 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 2020–2021 by multiplying spot market electricity prices from AURORA® 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-20-E-BPA-03, Section 3.3. The Power Loads and Resources Documentation, BP-20-E-BPA-03A, shows the 4(h)(10)(C) credit power purchase amount for FY 2020 in Table 6.1.1 and for FY 2021 in Table 6.1.2.

The direct program expenses and capital costs for FY 2020–2021 do not vary by water volume or flow timing and are documented in the Power Revenue Requirement Study Documentation, BP-20-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, Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01.

Results shown in Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Figures 6 and 7 reflect the probability distributions for the 4(h)(10)(C) credit during FY 2020–2021. The average 4(h)(10)(C) credit for the 3,200 games is $86.45 million for FY 2020 and $87.69 million for FY 2021. These values are included in the revenue forecast component of the Power Rates Study, BP-20-E-BPA-01, as described in Section 9.4.1 of that study. 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 AURORA® Runs)

Results from two runs of the AURORA® 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-20-E-BPA-04, § 2.4. Both runs produce 3,200 games of monthly HLH and LLH prices for FY 2020–2021. Figures 4 and 5 of the Power Market Price Study and Documentation provide a summary of the average monthly HLH and LLH prices for each of these AURORA® runs.

Prices from the market price run are used by RevSim to develop secondary energy revenues, firm surplus energy revenues, and balancing power purchase expenses for FY 2020–2021. 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 RAM2020 to develop rates for FY 2020–2021. 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 Sections 4.1.1.2.1, 4.1.1.2.2, 4.1.1.2.3, and 4.1.1.2.4, below for a description of this process.

Prices from the critical water run are used to compute the system augmentation costs provided to RAM2020 for ratemaking 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 4.1.1.2.1 below for a description of this process.

4.1.1.2 RevSim Model Outputs

RevSim model outputs are provided to RAM2020, the ToolKit model, and the revenue forecast component of the Power Rates Study, BP-20-E-BPA-01, Chapter 9.

4.1.1.2.1 System Augmentation Costs and Firm Surplus Energy Revenues

For this rate period, there is no system augmentation. If there were, deterministic values for system augmentation costs would be provided for input into RAM2020 by multiplying the system augmentation amount (aMW) by the average AURORA® price from the critical water run. The source of the system augmentation amounts is the Power Loads and Resources Study, BP-20-E-BPA-03, Section 4.2. A summary of the system augmentation costs calculation in this Study is shown in Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, 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 RAM2020.

Firm surplus energy revenues are treated in a manner similar to system augmentation costs. The deterministic values for firm surplus energy revenues provided to RAM2020 are calculated by multiplying the firm surplus energy amount (aMW) by the average AURORA® price from the market price run. The source of the firm surplus energy amounts is the Power Loads and Resources Study, BP-20-E-BPA-03, Section 4.3. The inclusion of the firm surplus energy revenues in RAM2020 reduces rates, since it is a revenue credit. This inclusion in RAM2020 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 Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, 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 2020 and 77 aMW in FY 2021, 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-20-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-20-E-BPA-03, Section 3.1.4, regarding the treatment of SILS forward power purchases, and Power Loads and Resources Study Documentation, BP-20-E-BPA-03A, Tables 9.1.1, 9.1.2, and 9.1.3, 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 generation by 2.97 percent. *See* Power Loads and Resources Study, BP-20-E-BPA-03, § 3.1.5.This is applied to 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.

Electricity prices estimated by AURORA® 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 Extra-regional Marketing in RevSim

Given that BPA has access to extra-regional 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. Extra-regional sales include CAISO transactions as well as bilateral transactions at COB and NOB, where BPA realizes a premium for COB and NOB sales 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 Southern Interties; the amount of excess available firm transmission capacity on the Southern Interties that PS has under contract; and the cost of transmission losses for sales over the interties. The source of the available excess transmission capacity and the price spreads is AURORA®. *See* Power Market Price Study and Documentation, BP-20-E-BPA-04, § 2.3.

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 AURORA® 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 extra-regional sales incur incremental transaction costs that are not observed at Mid-C. For the BP-20 rate period, BPA is eliminating the α coefficient methodology (as described in BP-18-FS-BPA-05, Section 4.1.1.2.3) that was used to discount the value of extra-regional sales. Instead, BPA is applying a 2 million dollar reduction to the modeled value of extra-regional sales. This decrement represents the sum of all known costs (excluding transmission losses) BPA will incur in association with these sales. As noted above, additional transmission losses are assessed to each unit of energy RevSim markets to California to account for losses associated with moving energy to COB or NOB over the interties.

Modeling extra-regional sales adds $18.0 million in FY 2020 and $18.7 million in FY 2021 to the net secondary energy revenue credits, as compared to modeling sales being made only at Mid-C.

4.1.1.2.4 Modeling Capacity Sales in RevSim

Starting in BP-20, forward capacity sales are modeled in RevSim. Bonneville has sold firm capacity rights to a counterparty guaranteeing said counterparty the right to call on up to 200 MW of energy from BPA on very short notice. This agreement goes into effect in CY 2021, impacting the last 9 months of the BP-20 rate period. Over this time, according to the structure of the agreement, BPA must hold 200 MW in reserve to provide to the counterparty, should they call for it. In compensation for this, BPA receives a monthly capacity fee. If they do call on some of the 200 MW, the counterparty is responsible for reimbursing BPA for the value of that energy, indexed to Mid-C.

This capacity agreement impacts RevSim in the calculation of extra-regional sales and in the committed sales revenue category. For any given period, when RevSim checks whether there is surplus energy available to market at COB or NOB, the first 200 MW are held exempt from consideration – it is effectively on reserve, held in case the counterparty calls for it. RevSim subsequently sells this holdout at Mid-C, which adequately models either BPA providing the energy to the counterparty and said counterparty compensating BPA at Mid-C prices, or BPA holding the energy when the counterparty does not call for it and then BPA marketing the

200 MW itself at Mid-C. The capacity payment BPA receives is included in the committed sales revenue category.

4.1.1.2.5 Mean Net Secondary Revenue Computations

Secondary energy revenues and balancing power purchases expenses for FY 2020–2021 are provided to RAM2020. These revenues and expenses are based on the arithmetic mean 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 RAM2020, both measured in annual average megawatts, are also the arithmetic means of these quantities over the 3,200 games for each fiscal year.

In the Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Tables 18 and 19 provide monthly values for the secondary energy sales/revenues and total power purchases/expenses provided to RAM2020 for FY 2020–2021. Annual secondary energy sales/revenues and total power purchases/expenses for FY 2020–2021 are reported in Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Table 20. The secondary energy revenues are $270.0 million for FY 2020 and $276.7 million for FY 2021. The total power purchases expenses are $63.2 million for FY 2020 and $46.8 million for FY 2021.

4.1.1.2.6 Net Revenue

RevSim results are used in an iterative process with ToolKit and RAM2020 to calculate PNRR and, ultimately, rates that provide BPA with at least 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 RAM2020, which in turn depend on the level of PNRR assumed when RAM2020 is run. RevSim simulates intermediate sets of net revenue during this iterative process. The final set of PS net revenue from RevSim is the lowest set that yields at least a 95 percent TPP.

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 financial reserves levels. The ToolKit calculates TPP from these games, and then analysts change the amounts of PNRR to achieve TPP targets. For BP-20, no PNRR was needed to meet the TPP target.

A statistical summary of the annual net revenue for FY 2020–2021 simulated by RevSim using proposed rates is reported in Table 1. PS net revenue over the rate period averages $88.2 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, FRP Surcharge, and RDC.

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-20-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 2019, P-NORM models the maximum O&M expense as 1.25 percent greater than forecast and the minimum as 1.25 percent less than forecast. For FY 2020 and FY 2021, 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 2019, FY 2020, and FY 2021, the most likely is set to the base NEIL premium amount. For FY 2019, 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 2020 and FY 2021, 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.

See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

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; and
- Additional costs due to new system requirements.

For additional security costs, P-NORM assumes for FY 2019, FY 2020, and FY 2021 that there is a 2 percent probability that an event will occur in any given year that leads to a requirement for additional security at the Corps or 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 for FY 2019, FY 2020, and FY 2021, with a 2 percent probability that an event that requires additional annual expenditures of $2 million each for either the Corps or Reclamation will occur in FY 2019 through FY 2021.

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 2019, FY 2020, and FY 2021, this risk is modeled with a 2.5 percent probability that an event will occur in any given year 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, system-wide event. This risk is modeled for FY 2019, FY 2020, and FY 2021 with a 1 percent probability of an event occurring in any given year resulting in a $30 million expense. 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 2019, FY 2020, and FY 2021 with a 10 percent probability of a $5 million expense in any given year. This risk is modeled in the same way for both the Corps and Reclamation.

See Table 2 for the expected, 5th percentile, and 95th percentile values for these risks.

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 2019 through FY 2021 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-20-E-BPA-02A, Table 3A.

Low-Income and Tribal Weatherization expense variability is modeled using a PERT distribution for FY 2019 through FY 2021. 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*.

See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

4.1.2.1.4 Spokane Settlement

Within the BP-20 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). For FY 2020 and FY 2021, 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-20-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 2020 or in FY 2021.

See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

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 2019 through FY 2021 with PERT distributions. For FY 2019, the minimum is set to 99 percent of the revenue requirement amount; the most likely value is set to the revenue requirement amount; and the maximum is set to 100.5 percent of the revenue requirement amount. For FY 2020, the minimum, most likely, and maximum are set to 96 percent, 100 percent, and 102 percent of the revenue requirement amounts. For FY 2021, the minimum, most likely, and maximum are set to 96 percent, 100 percent, and 103 percent of the revenue requirement amounts.

The cost of Third-Party Transmission and Ancillary Services is modeled for FY 2019 through FY 2021 using a PERT distribution with minimum and most likely values set to the revenue requirement amount. For FY 2019, FY 2020, and FY 2021, the maximums are set to 102.5 percent, 110 percent, and 116 percent of the revenue requirement amount.

See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

4.1.2.1.6 Fish & Wildlife Expenses

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

4.1.2.1.6.1. 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 2019, variation is not modeled for fish and wildlife expenses. For FY 2020 and FY 2021, 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. See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

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

Uncertainty in the expenses for the USFWS Lower Snake River Hatcheries is not modeled for FY 2019. For FY 2020 and FY 2021, uncertainty 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.

See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

4.1.2.1.6.3. 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 2019, FY 2020, and FY 2021 are included in the Bureau's O&M budget, which is discussed in Section 4.1.2.1.2 above.

See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

4.1.2.1.6.4. 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 2019, FY 2020, and FY 2021 are included in the Corps' O&M budget, which is discussed in Section 4.1.2.1.2 above.

See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

4.1.2.1.7 Interest Expense Risk

P-NORM models the impact of interest rate uncertainty associated with new fixed rate debt issuances and new and existing variable rate debt during the forecast period and the resulting interest expense impact. The planned borrowings and existing variable rate debt (Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Table 21) 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. Additionally, the interest rates charged on variable rate debt adjust periodically. P-NORM models uncertainty in the interest rate BPA will eventually receive for these borrowings and in the resulting interest expense. The analysis does not model uncertainty in the amount borrowed, term length of the borrowing, or timing of the borrowing.

P-NORM uses a table of high, expected, and low interest rates for FY 2019, FY 2020, and FY 2021, across terms of 1 to 30 years. Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Table 22. These interest rates are converted into a percent of expected value by dividing the high, expected, and low interest rate by the expected interest rate. For example, if the rates for debt with a tenor of one year are 1.5 percent, 2.0 percent, and 3.0 percent for the low, expected, and high values, then the resulting percent of expected value would be calculated by dividing each of those values by 2.0 percent (the expected rate). Thus, the low rate's percent of expected value would be 75 percent (1.5 percent divided by 2.0 percent), and the high rate's percent of expected value would be 150 percent (3.0 percent divided by 2.0 percent). The expected rate's percent of expected value will always be 100 percent.

For each modeled year, a discrete probability distribution is used to determine whether the low, expected, or high values are used in that year. The probability of low, expected, or high is modeled at 25 percent, 50 percent, and 25 percent respectively. The draw from that distribution determines which set of interest rate adjustments are used for that year and game. The input interest rate for any fixed rate debt issued in that year is adjusted by the drawn set of interest rate adjustments (*i.e.,* low, expected, or high) based on the tenor of the debt. If the tenor of the debt is less than 1 year, then the 1-year adjustment is used. If the tenor of the debt is greater than 30 years, then the 30-year adjustment is used. The interest rate for variable rate debt is adjusted in the same manner as fixed rate debt, except that the interest rate is adjusted again in each year after issuance.

See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

4.1.2.1.8 CGS Refueling Outage Risk

In the spring of 2019, Energy Northwest will take CGS out of service for refueling and maintenance. The same will occur in the spring of 2021. 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 2019 and FY 2021. This revenue variability is a function of plant outage duration, monthly flat AURORA® market prices, and monthly flat CGS energy amounts from RevSim.

The outage duration for FY 2019 and FY 2021 was modeled with a minimum of 36 days, a maximum of 61 days, and a median of 40 days.

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 AURORA® prices (*see* Power Market Price Study and Documentation, BP-20-E-BPA-04, § 2.4) are then multiplied by the gamed generation deviations, resulting in a net revenue deviation.

See Table 2 for the expected, 5th percentile, and 95th percentile values for this risk.

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 2019, FY 2020, and FY 2021. 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 Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Figure 8.

4.1.3 Net-Revenue-to-Cash Adjustment

P-NORM calculates 3,200 NRTC adjustments in order to make the necessary changes to convert RevSim and P-NORM accrual results (net revenue results) into the equivalent cash flows so ToolKit can calculate financial reserves values in each game and thus calculate TPP. *See* § 3.1.4 (NRTC Adjustments).

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-FS-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 Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Table 23.

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, the FRP Surcharge, 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 Treasury for that fiscal year. BPA's TPP standard, described in Section 2.4 above, defines a way to measure this risk (TPP) and a standard that reflects BPA's tolerance for this risk (no more than a 5 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 financial reserves for within-year liquidity ("liquidity reserves") has been defined.

4.2.1 Thresholds for CRAC, RDC, and FRP Surcharge

The FRP applies a consistent methodology to determine lower and upper financial reserves thresholds for each business line and an upper financial reserves threshold for BPA as a whole. *See* Appendix A (FRP). The lower and upper thresholds are used to determine when rate actions will be taken to increase or decrease financial reserves. These rate actions are implemented through the FRP Surcharge and the RDC. The FRP also establishes a $0 threshold for each business line, below which an additional rate action must be taken. This rate action is implemented through the CRAC.

4.2.1.1 Power Services Lower Financial Reserves Threshold

The Lower Financial Reserves Threshold for Power is the greater of 60 days cash or what is necessary to meet the Treasury Payment Probability (TPP) Standard. For this Rate Case, no additional financial reserves are needed to meet the TPP Standard, so the threshold is set at 60 days cash. The calculations of Power operating expenses and translations into days cash dollar amounts are shown in Table 3.

4.2.1.2 Power Services Upper Financial Reserves Threshold

The Upper Financial Reserves Threshold for Power is the Lower Financial Reserves Threshold plus 60 days cash. The calculations of Power operating expenses and translations into days cash dollar amounts are shown in Table 3.

4.2.1.3 Agency Upper Financial Reserves Threshold

The Agency (BPA) Upper Financial Reserves Threshold is the sum of the Power and Transmission Lower Financial Reserves Thresholds plus 30 days Agency cash. The Agency days cash dollar amounts are shown in Table 4.

4.2.1.4 ~~ANR~~ACNR Values for CRAC, RDC, and FRP Surcharge Thresholds

The thresholds for triggering the CRAC, RDC, and FRP Surcharge for Power are an amount of Power Services' Calibrated Net Revenue (CNR) accumulated since the end of FY 2018. These Accumulated Calibrated Net Revenue (~~ANR~~ACNR) thresholds are set at levels equivalent to the financial reserves thresholds established in the FRP. The CRAC thresholds (*i.e.*, both the FY 2020 CRAC threshold and the FY 2021 one) are set at the ~~ANR~~ACNR equivalent of $0 in Power Financial Reserves. The RDC thresholds are set at the ~~ANR~~ACNR equivalent of the Power Upper Financial Reserves Threshold and Agency Upper Financial Reserves Threshold. The FRP Surcharge Threshold is set at the ~~ANR~~ACNR equivalent of the Power Lower Financial Reserves Threshold.

These thresholds are calculated for each year by taking the difference between average ~~ANR~~ACNR and average financial reserves across all 3,200 games in the ToolKit and adding that difference to the target Power threshold in terms of financial reserves. As an example, assume that a given fiscal year's CRAC threshold is $0, in terms of financial reserves. If the average ~~ANR~~ACNR at the start of that fiscal year is $200 million, and the average financial reserves at the start of that fiscal year is $50 million, then the difference is $150 million ($200 million - $50 million). That difference is added to the target CRAC threshold, in terms of financial reserves, for a CRAC threshold of $150 million, in terms of ~~ANR~~ACNR ($0 + $150 million = $150 million).

Calibrations are included in CNR in order to adjust for certain events that change the relationship between Net Revenue and financial reserves relative to the relationship assumed in the rate case. 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 and cash contract settlements, are described in Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Example 1: Calibrated Net Revenue Calculations ("Example 1").

The Power CRAC thresholds are shown in Table 5. The Power RDC thresholds are shown in Table 6. The Agency RDC thresholds are shown in Table 7. The Power FRP Surcharge thresholds are shown in Table 8.

4.2.2 Power Risk Mitigation Tools

4.2.2.1 Liquidity

Cash and cash equivalents provide liquidity, which means they are available to meet immediate and short-term obligations. For purposes of BP-20 rate period risk modeling, Power Services has two sources of liquidity: (1) PS reserves and (2) the Treasury Facility. These liquidity sources are described further in Section 2.3.

4.2.2.1.1 PS Reserves

PS reserves at the start of FY 2019 are $12.7 million. This value was calculated as *total* financial reserves (see Section 2.3) attributed to PS of $191.4 million less $178.7 million of financial reserves not for risk. *See* https://www.bpa.gov/Finance/FinancialInformation/FinancialOverview/FY2018/Q4%20FY%202018%20Quarterly%20Financial%20Package.pdf and Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Table 24.

4.2.2.1.2 The Treasury Facility

For the purpose of TPP modeling for the BP-20 rate period, all $750 million of the Treasury Facility is modeled to be available for PS risk.

4.2.2.1.3 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 ratemaking risk mitigation purposes.

4.2.2.1.4 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 within-year liquidity. Thus, $430 million of the $750 million Treasury Facility is considered to be available for year-to-year liquidity for TPP.

4.2.2.1.5 Liquidity Reserves Level

Because the Treasury Facility fully meets the $320 million within-year liquidity need, no PS reserves need to be set aside for within-year liquidity, *i.e.,* the Liquidity Reserves Level is $0. Therefore, all PS reserves are considered to be available for the year-to-year liquidity needed to support TPP.

4.2.2.2 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 required by BPA's Financial Plan, then the projected financial 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.

PNRR needed to meet the TPP standard is calculated in the ToolKit, described in Section 3.1.5. 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 (BP-20-E-BPA-02), 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.

No PNRR is needed to meet the TPP standard for this Study.

4.2.2.3 Risk Adjustment Mechanisms

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 relatively quickly to financial circumstances BPA may experience, i.e., before the next opportunity to adjust rates in a rate proceeding. BPA has included three risk adjustment mechanisms for Power in BP-20: the Power CRAC, Power RDC, and Power FRP Surcharge. *See* §§ 2.4, 4.2.2.3.1-3. The Power rates and products subject to these risk adjustment mechanisms are Load Following, Block, the Block portion of Slice/Block, power purchased at the PF Melded rate, power purchased at the Industrial Firm Power rate, and power purchased at the New Resource Firm Power rate. *See* Power GRSPs II.O–P.

4.2.2.3.1 Power Cost Recovery Adjustment Clause (CRAC)

As described in Section 2.4 and Power GRSP II.O, the CRAC for FY 2020 and FY 2021 is a potential annual upward adjustment in various power rates. The Power CRAC explained here could increase rates for FY 2020 based on financial results for FY 2019. It also could increase rates for FY 2021 based on the accumulation of financial results for FY 2019 and FY 2020 (taking into account any Power CRAC applying to FY 2020 rates). The CRAC implements the FRP requirement for a rate action to increase financial reserves in the event that business line financial reserves fall below $0. *See* Appendix A (FRP), §4.2.3.

The ~~ANR~~ACNR thresholds for triggering the CRAC are described in Section 4.2.1.4. If triggered, the Power CRAC will recover 100 percent of the first $100 million that ~~ANR~~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 ~~ANR~~ACNR equivalent of negative $100 million in financial reserves at the end of the fiscal year, $100 million will be collected in the next year. At the ~~ANR~~ACNR equivalent of negative

$150 million, $125 million will be collected ($100 million plus 50 percent of the next $50 million). The Power CRAC will only trigger if the amount to be collected by the CRAC is greater than or equal to $5 million.

Calculations for the CRAC that could apply to FY 2020 and FY 2021 rates will be made early in that Fiscal Year by comparing actual ~~ANR~~ACNR through the end of the prior Fiscal Year to the CRAC Threshold. If ~~ANR~~ACNR is below the CRAC threshold by more than $5 million, an upward rate adjustment will be calculated for December through September of the fiscal year. *See* Power GRSP II.O.

4.2.2.3.2 Power Reserves Distribution Clause (RDC)

The Power RDC implements the FRP requirement for a financial reserves distribution in the event that financial reserves are above upper financial reserves thresholds. *See* Appendix A (FRP), § 4.1.

The ~~ANR~~ACNR thresholds for triggering the RDC are described in Section 4.2.1.4. The Power RDC is triggered if both BPA ~~ANR~~ACNR *and* Power Services ~~ANR~~ACNR are above specified thresholds. Above-threshold financial reserves will be considered for providing a downward adjustment to the same Power rates and products subject to the Power CRAC or for being deployed to other high-value business line-specific purposes. The total distribution is capped at $500 million per fiscal year. The RDC will only trigger if the RDC distribution amount is greater than or equal to $5 million. *See* Power GRSP II.P.

4.2.2.3.3 Power Financial Reserves Policy (FRP) Surcharge

The Power FRP Surcharge is a potential annual upward adjustment in various power rates. *See* Power GRSP II.Q. The Power FRP Surcharge applies to the same power rates that are subject to the Power CRAC. The Power FRP Surcharge implements the FRP requirement for a rate action to increase financial reserves in the event that business line financial reserves are below the Lower Financial Reserves Threshold. *See* Appendix A (FRP), §§ 4.2.1, 4.2.2.

The ~~ANR~~ACNR thresholds for triggering the FRP Surcharge are described in Section 4.2.1.4. For BP-20, the Power FRP Surcharge amount is capped at $30 million. If PS's FRP Surcharge Amount calculation results in a value less than $5 million, then PS's FRP Surcharge Amount is deemed to be zero.

4.2.3 ToolKit

The ToolKit model is described in Section 3.1.5. The inputs to the ToolKit for Power are shown in Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Figure 9.

4.2.3.1 ToolKit Inputs and Assumptions for Power

4.2.3.1.1 RevSim Results

The ToolKit reads in risk distributions generated by RevSim that are created for the current year, FY 2019, and the rate period, FY 2020–2021. TPP is measured for only the two-year rate period, but the starting financial reserves for FY 2020 depends on events yet to unfold in FY 2019; these runs reflect that FY 2019 uncertainty. See Section 4.1.1 for more detail on operating risk models.

4.2.3.1.2 Non-Operating Risk Model

The ToolKit reads in P-NORM distributions that are created for FY 2019–2021 and that reflect the uncertainty around non-operating expenses. See Section 4.1.2 of this Study for more detail on P-NORM.

4.2.3.1.3 Treatment of Treasury Deferrals

In the event that ToolKit forecasts a Treasury principal payment deferral, 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 financial reserves. The same applies to subsequent fiscal years if the repayment cannot be completed in the first year after the deferral.

4.2.3.1.4 Starting PS Reserves

The FY 2019 starting PS reserves have a known value of $12.7 million. See Section 4.2.2.1.1 above for a description of PS reserves.

4.2.3.1.5 Starting ~~ANR~~ACNR

The FY 2019 starting ~~ANR~~ACNR value of $0 million follows from the definition of ~~ANR~~ACNR: ~~accumulated PS net revenue~~CNR accumulated since the end of FY 2018. Each of the 3,200 games starts with this value.

4.2.3.1.6 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* § 4.2.2.1.5 above.

4.2.3.1.7 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 4.2.2.1.3 above, and the remaining $430 million to support PS TPP.

4.2.3.1.8 Interest Rate Earned on Financial 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 0.69 percent in FY 2019, 0.80 percent in FY 2020, and 0.82 percent in FY 2021.

4.2.3.1.9 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 financial 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 financial reserves, in the TPP calculations the values embedded in the RevSim results for interest earned on financial 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 $2.0 million for FY 2019, $2.3 million for FY 2020, and $3.0 million for FY 2021. *See* Power Revenue Requirement Study Documentation, BP-20-E-BPA-02A, Table 5A.

4.2.3.1.10 The Cash Timing Adjustment

The cash timing adjustment is a number from the repayment study that approximates the impact on earned interest of (1) the non-linear shape of PS reserves throughout a fiscal year, as well as (2) the interest earned on financial reserves attributed to PS that are not available for risk and are not modeled in the ToolKit. The ToolKit calculates interest earned on financial reserves by making the simplifying assumption that financial reserves change linearly from the beginning of the year to the end. That is, the ToolKit takes the average of the starting financial reserves and the ending financial reserves and multiplies that figure by the interest rate for that year. However, 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 financial reserves attributed to PS that are not available for risk (see Section 4.2.2.1.1 above) or the interest earned from these. The cash timing adjustment accounts for these two consequences of the ToolKit's simplifying assumption. The cash timing adjustments for this Study are $0 for FY 2019, $1.1 million for FY 2020, and $1.8 million for FY 2021.

4.2.3.1.11 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 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 iteratively generated PNRR to meet the TPP standard, there are no cash adjustments for PNRR.

4.2.4 Quantitative Risk Mitigation Results

Summary statistics are shown in Table 9.

4.2.4.1 Ending PS Reserves

Known starting PS reserves for FY 2019 are $12.7 million. The expected values of ending financial reserves are $47 million for FY 2019, $88 million for FY 2020, and $154 million for FY 2021. Over 3,200 games, the range of ending FY 2021 financial reserves is from negative $216 million to positive $747 million. The rate adjustment mechanisms would produce a CRAC of $158 million or an RDC of $500 million (if Agency ~~ANR~~ACNR is also high enough) in these extreme cases if the FY 2022 rates include mechanisms comparable to those included in the FY 2020–2021 rates. The 50 percent confidence interval for ending financial reserves for FY 2021 is $29 million to $273 million. ToolKit summary statistics for financial reserves and liquidity are in Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Figure 10 and Table 25.

4.2.4.2 TPP

The two-year TPP is greater than 99.9 percent. In 3,200 games, there are no deferrals for FY 2019, FY 2020, or FY 2021.

4.2.4.3 CRAC, RDC, and FRP Surcharge

The Power CRAC triggers for FY 2020 in 29 percent of games. The average Power CRAC amount is $20 million for FY 2020 (measured as the average amount across all 3,200 games). The Power CRAC also triggers for FY 2021 in 26 percent of games. The average Power CRAC amount is $17 million for FY 2021.

The Power RDC does not trigger in any of the 3,200 games for FY 2020. The Power RDC triggers in 0.5 percent of games for FY 2021, yielding an average amount of $0.5 million (measured as the average amount across all 3,200 games).

The Power FRP Surcharge triggers for FY 2020 in 99 percent of games. The average Power FRP Surcharge amount is $29.5 million for FY 2020 (measured as the average amount across all 3,200 games). The Power FRP Surcharge also triggers for FY 2021 in 93 percent of games. The average Power FRP Surcharge amount is $27.5 million for FY 2021.

Power CRAC, RDC, and FRP Surcharge statistics are shown in Table 9. The thresholds and caps for the Power CRAC, Power RDC, and Power FRP Surcharge applicable to rates for FY 2020 and FY 2021 are shown in Tables 5, 6, and 8. The BPA RDC Thresholds are shown in Table 7.

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, then additional risk treatment might be necessary. The two categories of risk analyzed here are (1) financial risks to BPA or to Tier 1 costs arising from BPA's provision of service at Tier 2 rates; and (2) financial risks to BPA or to Tier 1 costs arising from BPA's provision of Resource Support Services.

4.3.1 Risks Associated with Tier 2 Rate Design

For the FY 2020–2021 rate period, there is currently one Tier 2 rate with expected sales at that rate: the Tier 2 Short-Term rate. *See* Power Rates Study, BP-20-E-BPA-01, § 3.2.2. BPA expects to meet its load obligations for Tier 2 in FY 2020 and FY 2021 using firm power from the FCRPS or a market purchase for a flat annual block of power. *See id.*, § 3.2.2.1. One of the objectives guiding risk mitigation for the FY 2020–2021 rate period is to prevent risks associated with Tier 2 from increasing costs for Tier 1 or requiring increased mitigation for Tier 1. *See supra* § 2.1.

4.3.1.1 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 actual load is lower than the forecast amount used to set its Above-Rate Period High Water Mark (Above-RHWM) Load.
- A customer's actual load is higher than the forecast amount used to set its Above-RHWM Load.
- A customer does not pay for its Tier 2 service.
- 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.

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

Prior to BP-20, BPA executed 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. BPA expects any purchases it makes for Tier 2 in BP-20 to also be standard WSPP Schedule C contracts.

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-20-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 megawatt hours 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.

4.3.1.1.2 Risk: A Customer's Actual Load is Lower than the Forecast Amount Used to Set its Above-RHWM Load

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, 2016, with some modifications by October 31, 2018, for FY 2020 and FY 2021.

Using the Above-RHWM Loads that were computed in the RHWM Process, which concluded in August 2018, and the customers' elections, BPA has determined each customer's Above-RHWM Load served at a Tier 2 rate for the BP-20 rate period.

If the customer's actual load is lower than the BPA forecast used to calculate the customer's Above-RHWM Load amounts, then 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 Tier 2 rates. This approach protects BPA and Tier 1 purchasers from financial impacts of this event. The customer's load reduction could 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.

4.3.1.1.3 Risk: A Customer's Actual Load is Higher than the Forecast Amount Used to Set its Above-RHWM Load

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.

4.3.1.1.4 Risk: A Customer Does Not Pay for its Tier 2 Service

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.

4.3.1.1.5 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 makes 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. If BPA makes a power purchase to serve load at Tier 2 rates in FY 2020 and FY 2021, then the cost of those purchases will be allocated to the Tier 2 cost pool. *See* Power Rates Study, BP-20-E-BPA-01, § 3.2.2.1. Therefore, there is no risk that power purchase costs for Tier 2 service will be higher than the cost allocated.

If BPA does not make a power purchase to serve load at Tier 2 rates, or there is a remaining Tier 2 obligation not met with power purchases, then BPA will serve such load with firm power from the FCRPS. This unpurchased amount of Tier 2 energy is priced at the Remarketing Value for purposes of cost allocation. The Remarketing Values for FY20 and FY21 will either be equal to: (1) the price for a flat annual power block of power, if BPA makes a transaction for such power between November 1, 2018 and June 1, 2019, to be delivered in a fiscal year in the upcoming Rate Period; or (2) the average Intercontinental Exchange (ICE) MID-C settlement prices from two separate 5-consecutive-business-day periods (the last full week in September 2018 and the last full week in March 2019), plus $0.50 per megawatthour. The $0.50 per megawatthour adder is used to convert the financial settlement prices to ICE to a physically delivered price. *See* Power Rates Study, BP-20-E-BPA-01, § 3.2.2.6.

The ICE Mid-C financial settlement prices, plus the adder for converting to physical delivery, represent the cost BPA could transact at in advance for Tier 2 energy. Such forward market prices inherently include a risk premium for locking in a power purchase well in advance of delivery. This risk premium in the Remarketing Value used for Tier 2 energy costs helps ensure that Tier 2 rates are not subsidized by Tier 1 rates.

4.3.2 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-20-E-BPA-01A, Table 3.11.

4.3.2.1 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 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 $3 million annually. *See* Power Rates Study Documentation, BP-20-E-BPA-01A, Tables 3.2 and 3.7. The magnitude of the risk of miscalculation of these RSS costs is not large enough to affect TPP calculations.

4.3.3 Qualitative Risk Assessment Results

4.3.3.1 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.

4.3.3.2 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 TPP standard given the risks detailed in this chapter.

Variability in Transmission revenues is modeled in RevRAM, as described in Section 5.1.1. Variability in Transmission expenses and Net-Revenue-to-Cash (NRTC) adjustments are modeled in T-NORM, as described in Section 5.1.2. 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 network integration (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 (formerly known as Global Insight), 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 $4.0 million for FY 2020 and $4.1 million for FY 2021.

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 Program Evaluation and Review Technique (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-20 rate period.

Risk is also modeled for service that is eligible to be renewed during the rate period. Historical data is 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 is 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 are 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 are 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 to 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 per 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 $7.3 million for FY 2020 and $7.5 million for FY 2021.

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 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.

The short-term PTP risk distribution resulting from the methodology outlined above results in standard deviations of $10.7 million for FY 2020 and $10.5 million for FY 2021.

5.1.1.4 Long-Term Southern Intertie Service Revenue Risk

Long-term capacity on the Southern Intertie (IS) 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 $1.2 million for FY 2020 and $1.0 million for FY 2021.

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, so BPA models the risks around the NP-15 minus Mid-C price spread and South of Path 15 (SP-15) minus Mid-C spread. 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. The short-term IS revenue risk distribution results in standard deviations of $0.5 million for FY 2020 and $0.6 million for FY 2021.

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 $0.3 million per year for Utility and DSI Delivery revenue, $1.3 million per year for fiber and wireless contract revenue, and $1.3 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, (SCD), 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 (RFR), Dispatchable Energy Resource Balancing Service (DERBS), Variable Energy Resource Balancing Service (VERBS), Energy & Generation Imbalance (EI/GI), and Operating Reserve – Spinning & Supplemental (OR). These sources of revenue are sorted into two categories based on their characteristics and their impact on TS net revenue: (1) variable revenue with fixed expense, and (2) variable revenue with variable expense.

TS will pay PS for providing reserves for the Generation Inputs services, offset by Transmission revenue recovery, during the rate period.

Generation Inputs services 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—create insignificant uncertainty in TS net revenue. Therefore, no uncertainty in net revenue from these services 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 2020 is $114 million and for FY 2021 is $14 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 10 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 item. *See* Transmission Revenue Requirement Study Documentation, BP-20-E-BPA-09A, Table 3-1.

5.1.2.1.1 Transmission Operations

T-NORM models variability in transmission operations expense using PERT distributions for FY 2019 and for each of the two fiscal years in the rate period, FY 2020 and FY 2021. For FY 2019, 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 2009–2018) compared to rate case projections. The minimum value is 14 percent lower, and the maximum value is 9 percent higher, than the expected level of expense in the revenue requirement.

See Table 10 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 2019 and for each of the two fiscal years in the rate period. For FY 2019, 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 2009–2018) compared to rate case projections. The minimum value is 17 percent lower, and the maximum value is 30 percent higher, than the expected level of expense in the revenue requirement.

See Table 10 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 2019 and for each of the two fiscal years in the rate period. For FY 2019, 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 2009–2018) compared to rate case projections. The minimum value is 23 percent lower, and the maximum value is 15 percent higher, than the expected level of expense in the revenue requirement.

See Table 10 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 (1) new fixed rate debt issuances, and (2) new and existing variable rate debt during the forecast period, and the resulting interest expense impact. The planned borrowings and existing variable rate debt (Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Table 26) 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 4.1.2.1.7.

See Table 10 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 2019 and for each of the two fiscal years in the rate period. For FY 2019, 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 2009–2018) compared to rate case projections. The minimum value is 18 percent lower and the maximum value is 70 percent higher than the expected level of expense in the revenue requirement.

See Table 10 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 net-revenue-to-cash (NRTC) adjustments for each game for FY 2019, FY 2020, and FY 2021. 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 Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Figure 11.

5.1.3 Net-Revenue-to-Cash Adjustment

T-NORM calculates 3,200 NRTC adjustments in order to make the necessary changes to convert RevRAM and T-NORM accrual results (net revenue results) into the equivalent cash flows so ToolKit can calculate financial reserves values in each game and thus calculate TPP. *See* § 3.1.4 (NRTC Adjustments).

The NRTC Adjustment is the same across all 3,200 games in T-NORM, based on the deterministic expected values for each fiscal year's cash adjustments and non-cash adjustments. The NRTC table is shown in Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Table 27.

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, the CRAC, the FRP Surcharge, 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 its fiscal year, to fully meet its obligation to the U.S. Treasury for that fiscal year. BPA's TPP standard, described in Section 2.4 above, defines a way to measure this risk (TPP) and a standard that reflects BPA's tolerance for this risk (no more than a 5 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 that year. In each recent rate proceeding, a need for financial reserves for within-year liquidity ("liquidity reserves") has been defined.

5.2.1 Thresholds for CRAC, RDC, and FRP Surcharge

The FRP applies a consistent methodology to determine lower and upper financial reserves thresholds for each business line and an upper financial reserves threshold for BPA as a whole. *See* Appendix A (FRP). The lower and upper thresholds are used to determine when rate actions will be taken to increase or decrease financial reserves. These rate actions are implemented through the FRP Surcharge and the RDC. The FRP also establishes a $0 threshold for each business line, below which an additional rate action must be taken. This rate action is implemented through the CRAC.

5.2.1.1 Transmission Services Lower Financial Reserves Threshold

The Lower Financial Reserves Threshold for Transmission is the greater of 60 days cash or what is necessary to meet the Treasury Payment Probability (TPP) Standard.

For this Rate Case, no additional financial reserves are needed to meet the TPP Standard, so the Lower Threshold for Transmission is set at 60 days cash. The calculations of Transmission operating expenses and translations into days cash dollar amounts are shown in Table 11.

5.2.1.2 Transmission Services Upper Financial Reserves Threshold

The Upper Financial Reserves Threshold for Transmission is the Lower Threshold plus 60 days cash. The calculations of Transmission operating expenses and translations into days cash dollar amounts are shown in Table 11.

5.2.1.3 Agency Upper Financial Reserves Threshold

The Agency (BPA) Upper Financial Reserves Threshold is the sum of the Power and Transmission Lower Financial reserves Thresholds plus 30 days Agency cash. The Agency days cash dollar amounts are shown in Table 4.

5.2.1.4 ~~ANR~~ACNR Values for CRAC, RDC, and FRP Surcharge Thresholds

The thresholds for triggering the CRAC, RDC, and FRP Surcharge for Transmission are an amount of Transmission Services~~'~~ Calibrated Net Revenue (CNR) accumulated since the end of FY 2018. These Accumulated Calibrated Net Revenue (~~ANR~~ACNR) thresholds are set at levels equivalent to the financial reserves thresholds established in the FRP. The CRAC thresholds for FY 2020 and FY 2021 are set at the ~~ANR~~ACNR equivalent of $0 in Transmission financial reserves. The RDC thresholds are set at the ~~ANR~~ACNR equivalent of the Transmission Upper

Financial Reserves Threshold. The FRP Surcharge Threshold is set at the ~~ANR~~ACNR equivalent of the Transmission Lower Financial Reserves Threshold.

These thresholds are calculated for each year by taking the difference between average ~~ANR~~ACNR and average financial reserves across all 3,200 games in the ToolKit and adding that difference to the target Transmission threshold in terms of financial reserves. As an example, assume that a given fiscal year's CRAC threshold is $0, in terms of financial reserves. If the average ~~ANR~~ACNR at the start of that fiscal year is $200 million and the average financial reserves at the start of that fiscal year are $50 million, then the difference is $150 million ($200 million - $50 million). That difference is added to the target CRAC threshold, in terms of financial reserves, for a CRAC threshold of $150 million, in terms of ~~ANR~~ACNR ($0 + $150 million = $150 million).

Calibrations are included in CNR in order to adjust for certain events that change the relationship between Net Revenue and financial reserves relative to the relationship assumed in the rate case. The method for calculating Transmission CNR is described in Transmission GRSP II.G. Examples of the application of this method, including actions that change Federal depreciation and cash contract settlements, are described in Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Example 1.

The Transmission CRAC thresholds are shown in Table 12. The Transmission RDC thresholds are shown in Table 13. The Agency RDC thresholds are shown in Table 7. The Transmission FRP Surcharge thresholds are shown in Table 14.

5.2.2 Transmission Risk Mitigation Tools

5.2.2.1 Liquidity

Cash and cash equivalents provide liquidity, which means they are available to meet immediate and short-term obligations. For purposes of BP-20 rate period risk modeling, Transmission Services has one source of liquidity: TS reserves. TS reserves are described further in Section 2.3.

5.2.2.1.1 TS Reserves

TS reserves at the start of FY 2019 are $537.9 million. This value was calculated as *total* financial reserves (see Section 2.3 above) attributed to TS of $648.4 million less $110.5 million of financial reserves not for risk.

See https://www.bpa.gov/Finance/FinancialInformation/FinancialOverview/FY2018/Q4%20FY%202018%20Quarterly%20Financial%20Package.pdf and Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Table 28.

5.2.2.1.2 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. ToolKit records a Treasury payment miss if TS reserves fall below the within-year liquidity need.

The TS within-year liquidity need of $100 million was determined in the BP-16 rate proceeding, and that amount continues to be used for ratemaking risk mitigation purposes.

5.2.2.2 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 required by BPA's Financial Plan, then the projected financial 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.

PNRR needed to meet the TPP standard is calculated in the ToolKit, described in Section 3.1.5. 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-20-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.

No PNRR is needed to meet the TPP standard for this Study.

5.2.2.3 Risk Adjustment Mechanisms

The Transmission CRAC was first adopted in the BP-18 rate proceeding. *See* Power and Transmission Risk Study, BP-18-FS-BPA-05. BPA has included three risk adjustment mechanisms for Transmission in BP-20: the Transmission CRAC, Transmission RDC, and Transmission FRP Surcharge. *See* §§ 2.4, 5.2.2.3.1-3.

The Transmission rates subject to these risk adjustment mechanisms are the Network Integration Rate (NT-20), the Point-to-Point Rate (PTP-20), the Formula Power Transmission Rate (FPT-20.1), the Southern Intertie Point-to-Point Rate (IS-20), the Scheduling, Control, and Dispatch Rate (ACS-20 Section II.A and Section IV.B), the Utility Delivery Rate (Transmission GRSPs II.A.1.b.), and the Montana Intertie Rate (IM-20). *See* Transmission GRSP II.G-I.

5.2.2.3.1 Transmission Cost Recovery Adjustment Clause (CRAC)

As described in Section 2.4 and Transmission GRSP II.G, the CRAC for FY 2020 and FY 2021 is a potential annual upward adjustment in various Transmission rates. The Transmission CRAC explained here could increase rates for FY 2020 based on financial results for FY 2019. It also could increase rates for FY 2021 based on the accumulation of financial results for FY 2019 and FY 2020 (taking into account any Transmission CRAC applying to FY 2020 rates). The CRAC implements the FRP requirement for a rate action to increase financial reserves in the event that business line financial reserves fall below $0. *See* Appendix A (FRP), §4.2.3.

The ~~ANR~~ACNR thresholds for triggering the CRAC are described in Section 5.2.1.4. If triggered, the Transmission CRAC will recover 100 percent of the amount that ~~ANR~~ACNR is below the threshold, up to a cap of $100 million. The Transmission CRAC will only trigger if the amount to be collected by the CRAC is greater than or equal to $5 million.

Calculations for the CRAC that could apply to FY 2020 and FY 2021 rates will be made early in that Fiscal Year by comparing actual ~~ANR~~ACNR through the end of the prior Fiscal Year to the CRAC Threshold. If ~~ANR~~ACNR is below the CRAC threshold by more than $5 million, an upward rate adjustment will be calculated for December through September of the fiscal year. *See* Transmission GRSP II.G.

5.2.2.3.2 Transmission Reserves Distribution Clause (RDC)

The Transmission RDC implements the FRP requirement for a financial reserves distribution in the event that financial reserves are above upper financial reserves thresholds. *See* Appendix A (FRP), § 4.1.

The ~~ANR~~ACNR thresholds for triggering the RDC are described in Section 5.2.1.4. The Transmission RDC is triggered if both BPA ~~ANR~~ACNR *and* Transmission Services ~~ANR~~ACNR are above specified thresholds. Above-threshold financial reserves will be considered for providing a downward adjustment to the same Transmission rates that are subject to the Transmission CRAC or for being deployed to other high-value business line-specific purposes. The total distribution is capped at $200 million per fiscal year. The RDC will only trigger if the RDC distribution amount is greater than or equal to $5 million. *See* Transmission GRSP II.H.

5.2.2.3.3 Transmission Financial Reserves Policy (FRP) Surcharge

The Transmission FRP Surcharge is a potential annual upward adjustment in various transmission rates. *See* Transmission GRSP II.I. The Transmission FRP Surcharge applies to the same Transmission rates that are subject to the Transmission CRAC. The Transmission FRP Surcharge implements the FRP requirement for a rate action to increase financial reserves in the event that business line financial reserves are below the Lower Financial reserves Threshold. *See* FRP, §§ 4.2.1, 4.2.2.

The ~~ANR~~ACNR thresholds for triggering the FRP Surcharge are described in Section 4.2.1. The Transmission FRP Surcharge amount is capped at $15 million. If TS's FRP Surcharge Amount calculation results in a value less than $5 million, then TS's FRP Surcharge Amount is deemed to be zero.

5.2.3 ToolKit

The ToolKit model is described in Section 3.1.5. The inputs to the ToolKit for Transmission are shown in Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Figure 12.

5.2.3.1 ToolKit Inputs and Assumptions for Transmission

5.2.3.1.1 RevRAM Results

The ToolKit reads in risk distributions generated by RevRAM that are created for the current year, FY 2019, and the rate period, FY 2020–2021. TPP is measured for only the two-year rate period, but the starting financial reserves for FY 2020 depends on events yet to unfold in FY 2019; these runs reflect that FY 2019 uncertainty. See Section 5.1.1 for more detail on RevRAM.

5.2.3.1.2 Non-Operating Risk Model

The ToolKit reads in T-NORM distributions that are created for FY 2019–2021 and reflect the uncertainty around non-operating expenses. See Section 5.1.2 for more detail on T-NORM.

5.2.3.1.3 Treatment of Treasury Deferrals

In the event that the ToolKit forecasts a Treasury principal payment deferral, 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 financial reserves. The same applies to subsequent fiscal years if the repayment cannot be completed in the first year after the deferral.

5.2.3.1.4 Starting TS Reserves

The FY 2019 starting TS reserves have a known value of $537.9 million. See Section 5.2.2.1.1 above for a description of TS reserves.

5.2.3.1.5 Starting ~~ANR~~ACNR

The FY 2019 starting ~~ANR~~ACNR value of $0 million follows from the definition of ~~ANR~~ACNR: ~~accumulated TS net revenue~~CNR accumulated since the end of FY 2018. Each of the 3,200 games starts with this value.

5.2.3.1.6 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* Section 5.2.2.1.2 above.

5.2.3.1.7 Interest Rate Earned on Financial Reserves

Interest earned on the cash component and the Treasury Specials component of TS reserves is assumed to be 0.69 percent in FY 2019, 0.80 percent in FY 2020, and 0.82 percent in FY 2021.

5.2.3.1.8 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 financial 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 financial reserves, in the TPP calculations the values embedded in the T-NORM results for interest earned on financial 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 $3.6 million for FY 2019, $5.5 million for FY 2020, and $5.6 million for FY 2021. Transmission Revenue Requirement Study Documentation, BP-20-E-BPA 09A, Table 5-3.

5.2.3.1.9 The Cash Timing Adjustment

The cash timing adjustment is a number from the repayment study that approximates the impact on earned interest of (1) the non-linear shape of TS reserves throughout a fiscal year, as well as (2) the interest earned on financial reserves attributed to TS that are not available for risk and not modeled in the ToolKit. The ToolKit calculates interest earned on financial reserves by making the simplifying assumption that financial reserves change linearly from the beginning of the year to the end. That is, the ToolKit takes the average of the starting financial reserves and the ending financial reserves and multiplies that figure by the interest rate for that year. However, 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 financial reserves attributed to TS that are not available for risk (see Section 5.2.2.1.1 above) or the interest earned from these. The cash timing adjustment accounts for these two consequences of the ToolKit's simplifying assumption. The cash timing adjustments for this Study are negative $1.2 million for FY 2019, $0.2 million for FY 2020, and $0.1 million for FY 2021.

5.2.3.1.10 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 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.

5.2.4 Quantitative Risk Mitigation Results

Summary statistics are shown in Table 15.

5.2.4.1 Ending TS reserves

Known starting TS reserves for FY 2019 are $537.9 million. The expected values of ending net financial reserves are $536 million for FY 2019, ~~$500~~$471 million for FY 2020, and ~~$450~~$403 million for FY 2021. Over 3,200 games, the range of ending FY 2021 net financial reserves is from ~~$143~~$111 million to ~~$672~~$614 million. The rate adjustment mechanisms would not produce a CRAC for FY 2022 in the game with the lowest resulting net financial reserves if the FY 2022 rates include mechanisms comparable to those included in the FY 2020–2021 rates. In the game with the highest resulting net financial reserves, an RDC of $200 million would occur (if Agency ~~ANR~~ACNR is also high enough) for FY 2022 if the FY 2022 rates include mechanisms comparable to those included in the FY 2020–2021 rates. The 50 percent confidence interval for ending net financial reserves for FY 2021 is ~~$397~~$356 million to ~~$516~~$463 million. ToolKit summary statistics for financial reserves and liquidity are in Power and Transmission Risk Study Documentation, BP-20-E-BPA-05A-CC01, Figure 13 and Table 29.

5.2.4.2 TPP

The two-year TPP is over 99.9 percent. In 3,200 games, there are no deferrals for FY 2019, FY 2020, or FY 2021.

5.2.4.3 CRAC, RDC, and FRP Surcharge

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

The Transmission RDC triggers for FY 2020 47 percent of the time, yielding an expected value of $37 million in distributions. For FY 2021, Transmission RDC triggers ~~48~~ 38 percent of the time, yielding an expected value of ~~$43~~$31 million in distributions in that year.

The Transmission FRP Surcharge does not trigger in any of the 3,200 games. Transmission CRAC, RDC, and FRP Surcharge statistics are shown in Table 15. The thresholds and caps for the Transmission CRAC, Transmission RDC, and Transmission FRP Surcharge applicable to rates for FY 2020 and FY 2021 are shown in Tables 12, 13, and 14. The BPA RDC Thresholds are shown in Table 7.

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TABLES

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Table 1: RevSim Net Revenue Statistics for FY 2020 and FY 2021 ($ in millions)

	FY 2020	FY 2021
Mean	$89,238	$87,198
Median	$86,977	$88,094
Standard Deviation	$104,646	$110,806
Min	($138,054)	($165,590)
Max	$520,617	$510,567

1%	($98,609)	($117,459)
5%	($74,870)	($91,240)
10%	($57,613)	($69,718)
15%	($30,213)	($40,218)
20%	($5,513)	($13,641)
25%	$14,628	$7,054
30%	$29,065	$26,083
35%	$44,524	$42,913
40%	$60,265	$57,457
45%	$73,197	$73,241
50%	$86,977	$88,094
55%	$102,267	$101,790
60%	$115,301	$114,637
65%	$129,131	$129,947
70%	$143,158	$143,730
75%	$160,332	$161,872
80%	$177,997	$181,255
85%	$197,475	$202,627
90%	$224,526	$234,086
95%	$269,798	$272,271
99%	$344,987	$351,254

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**	Forecast	**5th Percentile**	**Mean**	**95th Percentile**
1	4.1.2.1.1	CGS Operations and Maintenance (O&M)	2019	327.4	326.5	326.7	326.9
2			2020	266.6	258.9	266.7	275.2
3			2021	323.8	314.5	324.1	334.4
4	4.1.2.1.2	U.S. Army Corps of Engineers (Corps) and Bureau of Reclamation (Reclamation) O&M	2019	418.7	418.7	420.4	424.7
5			2020	406.2	406.2	407.9	412.2
6			2021	404.2	404.2	405.9	410.2
7	4.1.2.1.3	Conservation Expense	2019	77.5	73.4	76.9	79.9
8			2020	72.7	68.9	72.2	75.0
9			2021	72.9	69.0	72.3	75.1
10	4.1.2.1.4	Spokane Settlement	2019	23.0	23.0	23.0	23.0
11			2020	23.0	23.0	23.6	28.7
12			2021	23.0	23.0	24.1	28.7
13	4.1.2.1.5	Power Services Transmission Acquisition and Ancillary Services	2019	95.8	94.8	95.7	96.4
14			2020	92.0	90.0	91.8	93.3
15			2021	92.1	90.0	92.0	93.9
16	4.1.2.1.6	Fish & Wildlife Expenses	2019	289.4	277.2	281.3	285.5
17			2020	280.1	267.8	271.8	275.7
18			2021	280.5	267.8	271.8	275.8
19	4.1.2.1.7	Interest Expense Risk	2019	67.3	67.0	67.7	69.3
20			2020	284.5	283.6	286.5	293.5
21			2021	283.5	282.7	287.8	300.0
22	4.1.2.1.8	CGS Refueling Outage Risk	2019	N/A	-4.1	-0.8	0.7
23			2020	N/A	0.0	0.0	0.0
24			2021	N/A	-7.1	-1.6	0.8

Table 3: Power Days Cash and Financial Reserves Thresholds

($ in millions)

		A	B
1		FY 2020	FY 2021
2	Total Expenses	$2,606	$2,633
	Less		
3	Net Interest Expense	$285	$285
4	Depreciation	$320	$324
5	Amortization	$139	$141
6	Non-Federal Debt Service	$0	$0
7	Contracted Power Purchases	$79	$68
8	Sum of rows 3-7	$824	$818
9	Operating Expenses (row 2 less row 8)	$1,783	$1,816
10	Operating Expenses divided by 360 (row 9/360)	$5.0	$5.0
11	Rate period average (average of row 10 column A and B)	$5.0	
12	**Lower Financial Reserves Threshold (row 11 * 60)**	**$300**	
13	**30 days cash on hand (row 11 * 30)**	**$150**	
14	**Upper Financial Reserves Threshold (row 11 * 120)**	**$600**	

**Due to accounting changes Starting in FY 2019, Non-Federal Debt Service is no longer included in expenses*

Table 4: Agency Upper Financial Reserves Threshold

($ in millions)

1		BP-20 Thresholds
2	Power Lower Financial Reserves Threshold	$300
3	Transmission Lower Financial Reserves Threshold	$94
4	Power 30 days cash on hand	$150
5	Transmission 30 days cash on hand	$47
6	**Agency Upper Financial Reserves Threshold (sum of rows 2 through 5)**	**$591**

Table 5: Power CRAC Thresholds and Caps
[Dollars in millions]

~~ANR~~ACNR Calculated from CNR for Fiscal Year(s)	*CRAC Applied to Fiscal Year*	*Threshold Measured in ~~ANR~~ACNR*	*Threshold Measured in PS Reserves*	*Maximum CRAC Recovery Amount (Cap)*
2019	2020	$234	$0	$300
2019 + 2020	2021	$331	$0	$300

Table 6: Power RDC Thresholds and Caps
[Dollars in millions]

~~ANR~~ACNR Calculated from CNR for Fiscal year(s)	*RDC Applied to Fiscal Year*	*Threshold Measured in Power ~~ANR~~ACNR*	*Threshold Measured in PS Reserves*	*Maximum RDC Amount (Cap)*
2019	2020	$834	$600	$500
2019 + 2020	2021	$931	$600	$500

Table 7: BPA RDC Annual Threshold
[Dollars in millions]

~~ANR~~ACNR Calculated from CNR for Fiscal Year(s)	*RDC Applied to Fiscal Year*	*Threshold Measured in BPA ~~ANR~~ACNR*	*Threshold Measured in BPA Financial Reserves*
2019	2020	$253	$591
2019 + 2020	2021	~~$364~~$392	$591

Table 8: Power FRP Surcharge Thresholds
[Dollars in millions]

~~*ANR*~~*ACNR* *Calculated from CNR for Fiscal Year(s)*	*FRP Surcharge Applied to Fiscal Year*	*Threshold Measured in* ~~*ANR*~~*ACNR*	*Threshold Measured in PS Reserves*	*Base Surcharge*
2019	2020	$534	$300	$30
2019 + 2020	2021	$631	$300	$30

Table 9: Power Risk Mitigation Summary Statistics
[Dollars in millions]

	A	B	C	D
		FY 2019	FY 2020	FY 2021
1	Two-Year TPP		99.9%	
2	PNRR	$20	$0	$0
3	CRAC Frequency	0%	29%	26%
4	Expected Value (EV) CRAC Revenue	$0	$20	$17
5	RDC Frequency	0%	0%	0%
6	EV RDC Payout	$0	$0	$0
7	FRP Surcharge Frequency	0%	99%	93%
8	EV Surcharge Revenue	$0	$30	$28
9	Treasury Deferral Frequency	0%	0%	0%
10	EV Treasury Deferral	$0	$0	$0
11	EV End of Year Financial Reserves	$47	$88	$154
12	Financial Reserves, 5th percentile	($122)	($119)	($115)
13	Financial Reserves, 25th percentile	($20)	($10)	$29
14	Financial Reserves, 50th percentile	$47	$79	$147
15	Financial Reserves, 75th percentile	$116	$176	$273
16	Financial Reserves, 95th percentile	$218	$327	$441

Table 10: T-NORM Risk Summary

	A	B	C	D	E	F	G
	T-NORM Risk Summary ($000,000)						
	Study Section	**Risk Title**	**Fiscal Year**	Forecast	**5th Percentile**	**Mean**	**95th Percentile**
1	5.1.3.1.1	Transmission Operations	2019	163.9	144.5	154.5	166.7
2			2020	168.5	148.5	158.8	171.3
3			2021	163.9	144.4	154.5	166.6
4	5.1.3.1.2	Transmission Maintenance	2019	170.3	150.8	173.4	199.1
5			2020	173.1	153.3	176.3	202.4
6			2021	173.3	153.5	176.5	202.7
7	5.1.3.1.3	Agency Service G&A	2019	97.2	83.2	94.9	106.0
8			2020	92.5	79.2	90.3	100.9
9			2021	93.9	80.4	91.7	102.4
10	5.1.3.1.4	Interest on Long-Term Debt	2019	143.6	143.5	143.6	143.7
11			2020	148.8	148.3	149.5	152.2
12			2021	162.0	161.4	164.4	171.3
13	5.1.3.1.5	Transmission Engineering	2019	53.0	51.2	65.4	80.1
14			2020	44.1	42.7	54.5	66.7
15			2021	49.5	47.9	61.1	74.8

Table 11: Transmission Days Cash and Financial Reserves Thresholds

	($ in millions)	A	B
1		FY 2020	FY 2021
2	Total Expenses	$1,058	$1,080
	Less		
3	Net Interest Expense	$149	$162
4	Depreciation	$0	$0
5	Amortization	$346	$353
6	Non-Federal Debt Service	$0	$0
7	Contracted Power Purchases	$0	$0
8	Sum of rows 3-7	$494	$515
9	Operating Expenses (row 2 less row 8)	$563	$565
10	Operating Expenses divided by 360 (row 9/360)	$1.6	$1.6
11	Rate period average (average of row 10 column A and B)	$1.6	
12	**Lower Financial Reserves Threshold (row 11 * 60)**	**$94**	
13	**30 days cash on hand (row 11 * 30)**	**$47**	
14	**Upper Financial Reserves Threshold (row 11 * 120)**	**$188**	

**Due to accounting changes Starting in FY 2019, Non-Federal Debt Service is no longer included in expenses*

Table 12: Transmission CRAC Thresholds and Caps

[Dollars in millions]

***~~ANR~~ACNR* Calculated from CNR for Fiscal Year(s)**	***CRAC Applied to Fiscal Year***	***Threshold Measured in ~~ANR~~ACNR***	***Threshold Measured in TS Reserves***	***Maximum CRAC Amount (Cap)***
2019	2020	($573)	$0	$100
2019 + 2020	2021	~~($555)~~($526)	$0	$100

Table 13: Transmission RDC Thresholds and Caps
[Dollars in millions]

~~ANR~~ACNR Calculated from CNR for Fiscal Year(s)	RDC Applied to Fiscal Year	Threshold Measured in Transmission ~~ANR~~ACNR	Threshold Measured in TS Reserves	Maximum RDC Amount (Cap)
2019	2020	($384)	$188	$200
2019 + 2020	2021	~~($367)~~($338)	$188	$200

Table 14: Transmission FRP Surcharge Thresholds and Caps
[Dollars in millions]

~~ANR~~ACNR Calculated from CNR for Fiscal Year(s)	FRP Surcharge Applied to Fiscal Year	Threshold Measured in ~~ANR~~ACNR	Threshold Measured in TS Reserves	Base Surcharge
2019	2020	($479)	$94	$15
2019 + 2020	2021	~~($461)~~($432)	$94	$15

Table 15: Transmission Risk Mitigation Summary Statistics
[Dollars in millions]

	A	B	C	D
		FY 2019	FY 2020	FY 2021
1	Two-Year TPP		99.9%	
2	PNRR	$0	$0	$0
3	CRAC Frequency	0%	0%	0%
4	Expected Value (EV) CRAC Revenue	$0	$0	$0
5	RDC Frequency	0%	47%	~~48%~~38%
6	EV RDC Payout	$0	$37	~~$43~~$31
7	FRP Surcharge Frequency	0%	0%	0%
8	EV Surcharge Revenue	$0	$0	$0
9	Treasury Deferral Frequency	0%	0%	0%
10	EV Treasury Deferral	$0	$0	$0
11	EV End of Year Financial Reserves	$536	~~$500~~$471	~~$451~~$403
12	Financial Reserves, 5th percentile	$498	~~$382~~$353	~~$279~~$241
13	Financial Reserves, 25th percentile	$520	~~$472~~$443	~~$397~~$356
14	Financial Reserves, 50th percentile	$536	~~$512~~$483	~~$471~~$421
15	Financial Reserves, 75th percentile	$551	~~$539~~$510	~~$516~~$463
16	Financial Reserves, 95th percentile	$572	~~$574~~$545	~~$567~~$513

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APPENDIX A: FINANCIAL RESERVES POLICY

1. Background and Purpose

The Financial Reserves Policy (Policy) provides a consistent, transparent, and financially prudent method for determining BPA's target ranges for financial reserves available for risk (financial reserves). The Policy establishes upper and lower financial reserves thresholds for Power Services, Transmission Services, and the agency as a whole, which define the target ranges. The Policy also describes the actions BPA may take when financial reserves levels either fall below a lower threshold or exceed an upper threshold. The Policy supports BPA's requirement to establish the lowest possible rates consistent with sound business principles.

Prior to the Policy, BPA did not have a consistent way to establish financial reserves target ranges and upper and lower financial reserves thresholds for each business line and BPA. This is of particular importance because financial reserves levels and financial reserves policies and practices have a direct effect on BPA's credit rating, which is determined at the aggregate BPA level. BPA, however, sets rates to recover costs for each business line individually. The lack of a consistent policy across the business lines and for BPA as a whole allows for *ad hoc* financial reserves decisions and different treatment for each business line.

Establishing prudent financial reserves lower thresholds over time for the business lines helps to maintain BPA's credit rating, solvency, and rate stability, which is consistent with sound business principles. Establishing prudent financial reserves upper thresholds for the business lines and BPA as a whole ensures that financial reserves do not grow to unnecessarily high levels but rather are invested back into the business or distributed as rate reductions, both of which lower revenue requirement costs.

2. Scope of the Financial Reserves Policy

The Policy affects financial reserves available for risk (financial reserves) attributed to Power Services (Power) and Transmission Services (Transmission).

The Policy establishes lower and upper financial reserves thresholds for Power Services and Transmission Services, and upper financial reserves thresholds for the agency at the ends of fiscal years. The Policy also provides guidance on the actions BPA should take when financial reserves fall below established lower threshold levels or rise above established upper threshold levels at the ends of fiscal years.

The Policy does not preclude or hinder in any way the Administrator's authority to use financial reserves for purposes deemed necessary by the Administrator.

The Policy is intended to provide a consistent framework within which BPA can manage its financial reserves. To that end, the Policy will constitute precedent that BPA will adhere to in future rate cases absent a determination by the Administrator that the Policy must be modified to meet BPA's changing operating environment.

3. Financial Reserves Thresholds

3.1 Definitions

Financial reserves available for risk. Financial reserves available for risk (financial reserves) consist of cash, market-based special investments, and deferred borrowing, all of which are highly liquid and unobligated for BPA to use to mitigate financial risk, less any outstanding balance on the Treasury Facility.

Days Cash on Hand Metric. Days cash on hand is the number of days a business can continue to operate using its own cash on hand with no new revenue. Days cash on hand is a common industry liquidity metric measuring the relationship between the amount of cash a business holds and the amount of average daily expenses incurred in operating the business.

3.2 Business Line Financial Target Ranges

Financial reserves target ranges for each business line shall be calculated independently each rate period, and consist of upper and lower financial reserves thresholds, which define the upper and lower ends of the target ranges.

3.3 Lower Financial Reserves Thresholds

Lower financial reserves thresholds shall be calculated independently for Power and Transmission each rate period based on the greater of: (1) 60 days cash on hand, and (2) what is necessary to meet the Treasury Payment Probability (TPP) Standard. For each business line, if financial reserves fall below the lower threshold, a rate action shall trigger the following fiscal year to recover, in part or in whole, the shortfall.

3.4 Upper Financial Reserves Thresholds

Upper financial reserves thresholds shall be calculated independently for Power and Transmission each rate period and will be the financial reserves' equivalent of 60 days cash on hand above the lower financial reserves thresholds. The agency upper threshold is the sum of Power and Transmission's lower thresholds plus 30 days cash on hand for the agency.

3.4.1 Financial Reserves Distributions

If business line financial reserves and agency financial reserves are above their respective upper thresholds, the Administrator shall consider the above-threshold financial reserves for investment in other high-value business line-specific purposes including, but not limited to, debt retirement, incremental capital investment, or rate reduction.

3.5 Calculation of Lower and Upper Financial Reserves Thresholds

3.5.1 - Power Services		
Power lower financial reserves threshold	=	The greater of: (1) 60 days * (Power operating expenses / 365 days), and (2) the threshold needed to achieve a 95% TPP.
Power upper financial reserves threshold	=	Power lower financial reserves threshold plus 60 days * (Power operating expenses / 365 days)
Where:		
Power operating expenses	=	Power total expenses – (Power depreciation and amortization + Power net interest expense + Power non-federal debt service + Power purchases)

3.5.2 - Transmission Services		
Transmission lower financial reserves threshold	=	The greater of: (1) 60 days * (Transmission operating expenses / 365 days), and (2) the threshold needed to achieve a 95% TPP.
Transmission upper financial reserves threshold	=	Transmission lower financial reserves threshold plus 60 days * (Transmission operating expenses / 365 days)
Where:		
Transmission operating expenses	=	Transmission total expenses – (Transmission depreciation & amortization + Transmission net interest expense)

3.5.3 - Agency		
Agency upper financial reserves threshold	=	The sum of the Power lower financial reserves threshold and the Transmission lower financial reserves threshold plus 30 days cash on hand for the agency
Where:		
30 days cash on hand for the agency	=	30 days * (agency operating expenses / 365 days)
Agency operating expenses	=	Power operating expenses + Transmission operating expenses

4. Implementation

4.1 Overview

The Policy will be implemented each rate period through the Power and Transmission rate schedules and GRSPs. The lower and upper financial reserves thresholds for each business line will be recalculated each time BPA establishes new Power and Transmission rates. Lower and upper financial reserves thresholds will remain constant throughout each rate period. Lower and upper financial reserves thresholds will be computed using forecast rate period average operating expenses from the Power and Transmission revised revenue tests.

Implementation shall include parallel rate mechanisms for each business line each rate period that will trigger if financial reserves are below the lower financial reserves thresholds. Implementation shall also include parallel Financial Reserves Distributions for each business line each rate period that will trigger if financial reserves are above upper financial reserves thresholds.

4.2 Provisions for Increasing Financial Reserves

The methodologies for increasing financial reserves are described below. The specific rate mechanisms to achieve 4.2.1 through 4.2.3 will be determined in the applicable rate proceeding.

4.2.1 Except as provided in section 4.2.2, if financial reserves attributable to a business line are below its lower threshold, then the annual rate action will be the lower of the following two, unless a larger increase in reserves is necessary to achieve the TPP standard:

(1) $40 million per year in Power rates, if recovering Power financial reserves; $15 million per year in Transmission rates, if recovering Transmission financial reserves; or

(2) the amount needed to fully recover financial reserves up to the applicable business line lower threshold.

4.2.2 The $40 million per year rate action described above in section 4.2.1(1) is being phased in for Power until Fiscal Year (FY) 2022. In FY 2022 and thereafter, the $40 million per year rate action in section 4.2.1(1) will apply and this section 4.2.2 will be inapplicable. In FY 2020 and FY 2021, if financial reserves attributable to Power are below its lower threshold, then the annual rate action will be the lower of the following two, unless a larger increase in reserves is necessary to achieve the TPP standard:

(1) $30 million per year in Power rates; or

(2) the amount needed to fully recover financial reserves up to the Power lower threshold.

4.2.3 In addition to the rate action described above in sections 4.2.1 and 4.2.2, Bonneville will initially propose in each rate case a rate mechanism to increase each business line financial reserves in the event they fall below $0. Such rate mechanism will include the following parameters:

(1) When financial reserves are below $0 for Power Services, Bonneville will recover in each year of the rate period the first $100 million dollar-for-dollar. Bonneville will recover only fifty cents on the dollar for any amounts greater than $100 million. This provision will be limited to an annual cap of $300 million; and

(2) When financial reserves are below $0 for Transmission Services, Bonneville will recover in each year of the rate period the first $100 million dollar-for-dollar. This provision will be limited to an annual cap of $100 million.

Implementation of the methodology described above, including the timing of when the calculations in (1) and (2) will be performed, will be determined each rate period through the Power and Transmission rate schedules and GRSPs. Such implementation may include *de minimis* thresholds.

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